Integrating non-dispatchable renewable energy into the South African grid. An energy balancing view.

L K du Plessis

10856501

Dissertation submitted in partial fulfilment of the requirements for the degree, *Master of Engineering* at the Potchefstroom Campus of the North-West University, South Africa

Supervisor: Prof P W Stoker

November 2012

Acknowledgements

Firstly I would like to thank our Creator and Heavenly Father for the opportunity and talents He has blessed me with in order for me to have participated in this Master's degree.

I want to thank my supervisor, Prof. Stoker, for the inspiration, guidance and contributions that he has had in this study.

I also would like to thank my wife for the inspiration she has been in my life. For kicking me out of bed at three o'clock in the mornings over weekends before the children got up. For entertaining and keeping the children busy as well as for the numerous cups of tea she served me with during my time of study.

At the same time I would like to apologise to my daughters Sulise, aged four, and Livia, aged two, for the fun times that we missed out on as a result of these studies. I love you very much and I will hopefully make it up to you.

Abstract

The integration of dispatchable renewable energies like biomass, geothermal and reservoir hydro technologies into an electrical network present no greater challenge than the integration of conventional power technologies for which are well understood by Eskom engineers. However, renewable energies that are based on resources that fluctuate throughout the day and from season to season, like wind and solar, introduce a number of challenges that Eskom engineers have not dealt with before.

It is current practice for Eskom's generation to follow the load in order to balance the demand and supply. Through Eskom's load dispatching desk at National Control, generator outputs are adjusted on an hourly basis with balancing reserves making up only a small fraction of the total generation.

Through the Integrated Resource Plan for Electricity of 2010, the Department of Energy has set some targets towards integrating renewable energy, including wind and solar generation, into the South African electricity market consequently introducing variability on the supply side.

With demand that varies continually, maintaining a steady balance between supply and demand is already a challenging task. When the supply also becomes variable and less certain with the introduction of non-dispatchable renewable energy, the task becomes even more challenging.

The aim of this research study is to determine whether the resources that previously helped to balance the variability in demand will still be adequate to balance variability in both demand and supply. The study will only concentrate on variable or non-dispatchable renewable energies as will be added to the South African electrical network according to the first two rounds of the Department of Energy's Renewable Energy Independent Power Producer Procurement Programme.

This research study only looks into the balancing challenge and does not go into an analysis of voltage stability or network adequacy, both of which warrant in depth analysis.

Keywords:

- Dispatchable
- Non-dispatchable
- Renewable energy
- Demand and supply
- Balancing reserves
- Operating reserves
- Generator ramp rates
- Integrated Resource Plan for Electricity of 2010
- Wind turbine generators
- Electricity market
- Independent Power Producer Procurement Programme
- REBID programme
- Grid code
- Embedded generators

Table of Contents

List of Tables

List of Figures

Nomenclature

AC	Alternating Current
AEP	Annual Energy Production
AGC	Automatic Generation Control
BPC	Botswana Power Corporation
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
CSP	Concentrated Solar Power
DC	Direct Current
DMP	Demand Market Participation
EDM	Eléctricidade de Moçambique
EDP	Economic Dispatch Principle
EL1	Emergency Level 1
EU	European Union
GW	Gigawatt
HV	High Voltage
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
ILS	Interruptible Load Shedding
IPP	Independent Power Producer
IPS	Interconnected Power System
IR	Instantaneous Reserves
IRP	Integrated Resource Plan
kV	kilovolt
LEC	Lesotho Energy Corporation
LFC	Load Frequency Characteristics

LFI	Low Frequency Incident
MCR	Maximum Continuous Rating
MV	Medium Voltage
MW	Megawatt
NWA	Numerical Wind Atlas
OCGT	Open Cycle Gas Turbine
OECD	Organisation for Economic Co-operation and Development
PSO	Public Service Obligation
PV	Photo Voltaic
RDE	Royal Danish Embassy
RE	Renewable Energy
REBID	Renewable Energy Bids
REFIT	Renewable Energy Feed-In Tariff
RFP	Request for Qualification and Proposals
SAPP	Southern African Power Pool
SAWEP	South African Wind Energy Programme
SCADA	Supervisory Control and Data Acquisition
SEB	Swaziland Electricity Board
SO	System Operator
TEMSE	Transmission Engineering Management System Evolution
TSO	Transmission System Operator
TWh	Terawatt hour
UFLS	Under Frequency Load Shedding
WASA	Wind Atlas of South Africa

Chapter 1

This chapter introduces the dissertation, focussing on the research problem, the objectives and the outline of the research.

Chapter 1 : Introduction

1.1 Introduction

Electrical energy cannot be stored economically in large quantities and consequently it must be used as it is generated. It is crucial that the amount of electrical energy needed at any point in time should be matched by the amount generated. With the demand that varies continually, maintaining a steady balance between supply and demand is already a challenging task. When the supply also becomes variable and less certain with the introduction of non-dispatchable renewable energy, the task becomes even more challenging.

This chapter gives an overview of the South African electrical network. It introduces the reader to the Integrated Resource Plan for Electricity of 2010 and the targets it contains towards integrating renewable energy into the South African electrical network. It introduces the reader to the Department of Energy's Renewable Energy Independent Power Producer Procurement Programme and identifies a number of challenges that the System Operator at Eskom will face when integrating renewable energy into the South African electrical network. This chapter also gives the research objectives and an outline of the dissertation.

1.2 The South African electrical network

Eskom is South Africa's primary supplier of electrical energy and is entirely owned by the South African government. According to Eskom's latest annual report, it supplies approximately 95% of South Africa's electrical energy and more than 40% of Africa's electrical energy. It sells electrical energy directly to about 3000 industrial customers, 1000 mining customers, 50 000 commercial customers and 84 000 agricultural customers. It also supplies electrical energy to more than 4.7 million residential customers. For Eskom's financial year ending 31 March 2012 the total amount of electrical energy generated amounted to 241.4 TWh with the national peak load during that time being approximately 37 GW (Eskom Holdings SOC Limited, 2012).

The South African electrical network is presently divided into seven geographical regions, each with a transmission and a distribution network including re-distributors (e.g. municipalities). As a net exporter of energy, Eskom's network is interconnected with five neighbouring countries as follows; Namibia at 400 kV and 220 kV, Botswana at 400 kV and 132 kV, Swaziland at 400 kV and 132 kV, Mozambique at 400 kV and 275 kV, and Lesotho at 132 kV. Energy import into South Africa to the amount of 1700 MW is from Mozambique only, via two 533 kV DC lines.

Transmission voltage levels are 765 kV, 400 kV, 275 kV and 220 kV while 132 kV, 88 kV, 66 kV, 33 kV, 22 kV, 11 kV and 6.6 kV form part of the sub-transmission and distribution networks. Transmission, sub-transmission and distribution networks are predominantly overhead lines. The medium voltage (MV) distribution networks within urban areas however, are 11 kV buried cables while the rural networks are predominately 22 kV overhead lines. The total length of Eskom's overhead lines adds up to 388 335 km while the total length of buried cable adds up to 11 415 km. The total transformer capacity for Transmission and Distribution is 132 995 MVA and 104 185 MVA respectively (Eskom Holdings SOC Limited, 2012).

Most of the country's base generation is thermal and is situated in Mpumalanga and Limpopo Provinces with two 955 MW of nuclear units situated in the Western Cape Province. The peaking stations consist of pumped storage of four 250 MW units at Drakensberg in the KwaZulu-Natal Province and two 200 MW units at Palmiet in the Western Cape Province. Soon to be added in the KwaZulu-Natal Province are four 325 MW units at Ingula in close proximity to the Drakensberg units. The southern and western coastline comprises gas and liquid fuel turbines with a net output of 2426 MW.

Eskom's current generation mix is as indicated in Table 1 (Eskom Holdings SOC Limited, 2012).

Table 1: Eskom's current generation mix (Eskom Holdings SOC Limited, 2012)

Type	Number	Nominal Capacity
Coal-fired	13 stations	37 715 MW
Gas/liquid fuel turbine	4 stations	2426 MW
Hydroelectric	6 stations	661 MW
Pumped storage	2 stations	1400 MW
Nuclear	1 station	1910 MW
Wind energy	1 station	3 MW
Total	**27 stations**	**44 115 MW**

An overview of the South African electrical network is shown in Figure 1.

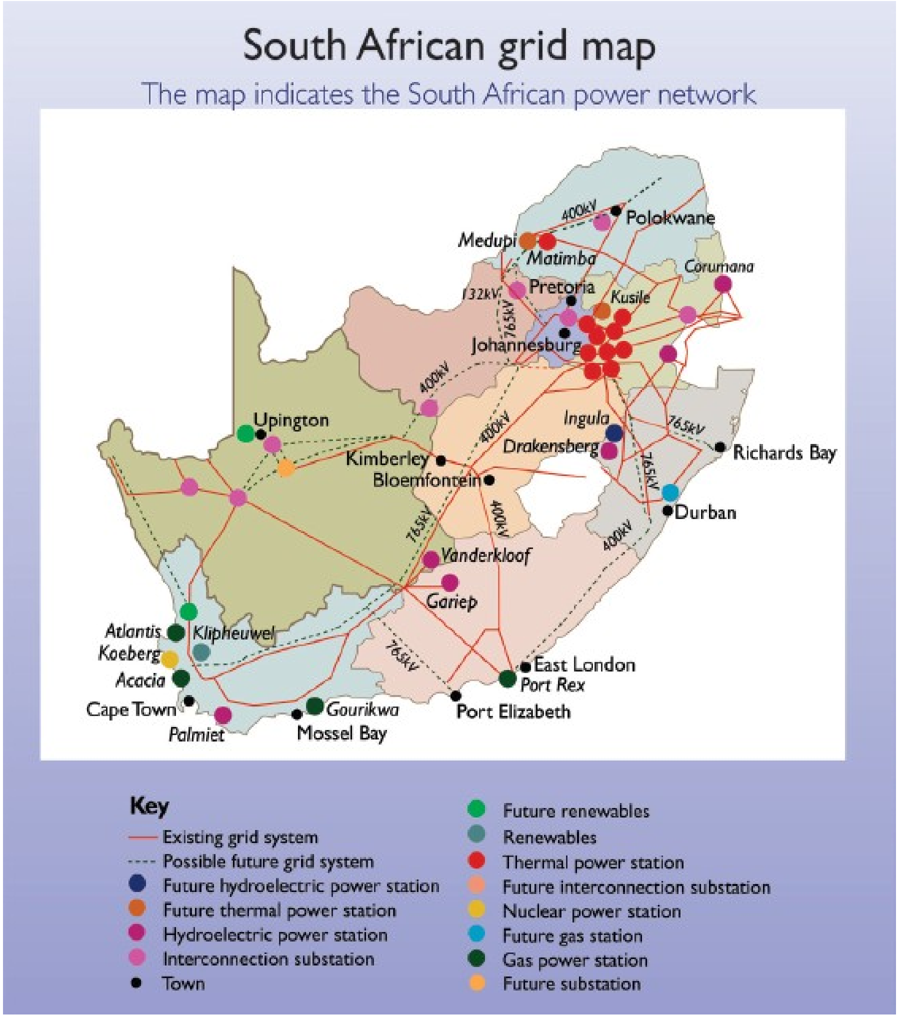

Figure 1: Eskom's power grid (Eskom Holdings SOC Limited, 2012)

1.3 Introducing renewable energy into the South African network

According to the White Paper on Renewable Energy (Department of Minerals and Energy, 2003), the South African government targets 10 TWh to be generated annually from renewable sources by the year 2013. This equates to an average output of 1142 MW from renewable resources throughout the year.

Eskom supports the 10 TWh Government target, as one of Eskom's strategic imperatives is to reduce its carbon footprint. Also, Eskom views renewable energy to play a critical role in achieving both growth in the supply of electrical energy and diversification from reliance on coal. In its support, Eskom is finalising plans for a wind farm at Sere near Koekenaap in the Western Cape Province, due for completion in December 2013. Eskom is also finalising plans for a pilot concentrating solar thermal power plant near Upington in the Northern Cape Province, due to start construction in December 2015. Together, these will add 200 MW of power to the grid when completed (Eskom Holdings SOC Limited, 2012).

1.4 IRP 2010

The process of formulating a suitable renewable resources development strategy culminated during 2010 in the Integrated Resource Plan for Electricity. This plan was subjected to public scrutiny and proposals from all sectors of the South African energy generation industry. Subsequently, at a Cabinet meeting held during March 2011, Cabinet approved the Integrated Resource Plan for Electricity (2010 – 2030) as the basis for South African power generation for the next 20 years. The plan, which has been promulgated by the Department of Energy is geared towards a low carbon future and is aligned with the country's long-term mitigation scenarios which allow greenhouse gas emissions to peak, plateau and decline in line with national government's aspiration.

Between 2011 and 2030, 42% of the new build programme excluding the current committed Eskom build programme will be from renewable energy sources. It is anticipated that the percentage of energy generated from CO_2 free sources (including nuclear energy) will be approximately 30% by the year 2030.

The layout of the new-build technology mix as published in the final Integrated Resource Plan (IRP) 2010 is according to Table 2 (Department of Energy - Republic of South Africa, 2011).

Table 2: IRP 2010: New-build technology mix (Department of Energy - Republic of South Africa, 2011)

Energy source	Energy generator	New capacity to be build (MW)	Percentage break-down (%)
Hydrocarbon (41.9%)	Coal	16 383	29.0
	OCGT (diesel)	4930	8.7
	CCGT (gas)	2370	4.2
Renewable energy (38.1%)	Wind	9200	16.3
	Solar PV	8400	14.9
	Solar CSP	1200	2.1
	Imported hydro	2659	4.6
	Landfill, small hydro	125	0.2
Nuclear (17.0%)	New-build	9600	17.0
Pumped storage (2.4%)	After Ingula PS	1332	2.4
Co-generation (0.7%)	Own build	390	0.7
Total		**56 539 MW**	**100%**

1.5 RSA renewable energy applications for the REBID programme

The Department of Energy (DoE) formally launched the Renewable Energy Independent Power Producer (RE IPP) Procurement Programme on 3 August 2011.

Through the DoE’s Request for Proposal (RFP), developers were invited to submit proposals for the financing, construction, operation and maintenance of any onshore wind, solar thermal, solar photovoltaic, biomass, biogas, landfill gas, or small hydro technologies. The RFP calls for 3725 MW of RE technologies to be in commercial operation between mid-2014 and the end of 2016. The order of magnitude for renewable energy capacities allocated by the Department of Energy to the various technologies is as per Table 3 (Department of Energy - Republic of South Africa, 2011).

Table 3: Allocated capacity across selected renewable energy technologies for development before 2016 (Department of Energy - Republic of South Africa, 2011)

RE technology	**Allocated capacity**	
	(MW)	**(%)**
Onshore wind	1850	49.7
Solar CSP	200	5.4
Solar PV	1450	38.9
Biomass	12.5	0.3
Biogas	12.5	0.3
Landfill Gas	25	0.7
Small Scale Hydro	75	2.0
Small scale IPP	100	2.7
Total	**3725 MW**	**100%**

The REBID programme is structured as a competitive bid tender, subject to the price not being higher than the tariff cap per technology set by Government. Although earlier information was that the 2009 Renewable Energy Feed-In Tariff (REFIT) would act as an upper limit on price, the actual caps are as indicated in Table 4 (Ash *et al.*, 2011).

The electrical energy generated through the renewable resources will be on a take-or-pay basis implying that when these resources are available to generate Eskom will be obliged to include them as part of the generation mix or otherwise pay for those specified quantities if not taken (NERSA, 2011).

Eskom's latest annual report indicated that the average cost of electrical energy for the year ending 31 March 2012, was 41.3 cents per kWh (Eskom Holdings SOC Limited, 2012). This is low in comparison with the renewable energy tariffs that will range between 80 cents per kWh and 285 cents per kWh.

Table 4: Tariff caps for the different RE technologies (Ash *et al.*, 2011)

RE technology	Tariff cap (R/MWh)
Onshore wind	1150
Solar CSP	2850
Solar PV	2850
Biomass	1070
Biogas	800
Landfill Gas	840
Small Scale Hydro	1030
Small scale IPP	1030

The programme is a rolling procurement process, which will end once all capacities per technology have been achieved. It is intended to have five bidding windows with closing dates of 4 November 2011, 5 March 2012, 20 August 2012, 4 March 2013 and 13 August 2013 respectively. If the target MW for any particular technology has been reached during any particular window, the subsequent windows will not be opened for that technology.

The initial market response to this programme was positive, with more than 270 bidder applications reported to have been received. As part of the REBID process, bidders had to first show how their project would deliver social and economic development for South Africans. Only those with acceptable social and economic plans could advance to have their projects judged on feasibility and price (Kernan, 2012).

It is estimated that by the end of the five window bid process, the Independent Power Producer (IPP) programme will attract project proposals to the value of R100 billion over its lifetime (Department of Energy - Republic of South Africa, 2012).

1.5.1 First round of bid submissions

The first round for bid submissions of the DoE's RE IPP Procurement Programme closed on 4 November 2011. A total of 53 bids were received with a total capacity of 2100 MW. Unfortunately a large number of bids did not comply with the bid criteria. Wind (1050 MW) and solar (1008 MW) technologies made up most of the total capacity. Small scale hydro accounted only for 42 MW. The DoE announced that 28 bids were successful and a total of 1416 MW were allocated to the 28 bidders as per Table 5 below. With this achievement, Window 1 surpassed the targeted 1000 MW, which was to be reached by the end of 2012 (Department of Energy - Republic of South Africa, 2012).

Table 5: Round 1 successful bids (Department of Energy - Republic of South Africa, 2012)

Technology	Number of bids	Total MW allocated
Solar PV	18	632
Solar CSP	2	150
Wind	8	634
Total	**28**	**1416 MW**

A total capacity of 2209 MW was still available for the subsequent procurement rounds excluding the 100 MW, which was set aside for small projects targeting RE projects between 1 MW and 5 MW in size.

1.5.2 Second round of bid submissions

The second round for bid submissions of the DoE’s RE IPP Procurement Programme closed on 5 March 2012. The capacity allocation was limited to 1275 MW for this round. A total of 79 bids were received totalling more than 3200 MW. The DoE announced on 21 May 2012 that nineteen bids were successful and a total of 1043 MW were allocated to the nineteen bidders as per Table 6 (Department of Energy - Republic of South Africa, 2012).

Table 6: Round 2 successful bids (Department of Energy - Republic of South Africa, 2012)

Technology	Number of bids	Total MW allocated
Solar PV	9	417
Solar CSP	1	50
Wind	7	562
Small Hydro	2	14
Total	**19**	**1043 MW**

A total capacity of 1266 MW is still available for the subsequent procurement rounds, again excluding the 100 MW, which was set aside for small projects.

The current status of the RE IPP programme is summarised in Table 7.

Table 7: Current status of the RE IPP programme

Technology	Tariff cap (R/MWh)	Total programme allocation (MW)	Round 1 allocation (MW)	Round 2 allocation (MW)
Onshore Wind	1150	1850	634	562
Solar PV	2850	1450	632	417
Solar CSP	2850	200	150	50
Biomass	1070	12.5	0	0
Biogas	800	12.5	0	0
Landfill Gas	840	25	0	0
Small Hydro	1030	75	0	14
Small scale RE	1030	100	0	0
Total		**3725**	**1416**	**1043**

1.6 Identification of the research problem

The integration of dispatchable renewable energies like biomass, geothermal and reservoir hydro technologies present no greater challenge than the integration of conventional power technologies. However, variable or non-dispatchable RE technologies making use of wind and solar that are based on resources that fluctuate throughout the day and from season to season, introduce a number of challenges to the operators of any electrical utility. Integrating these types of RE technologies into electrical grids requires additional effort. The higher the penetration levels of these types of renewable energies become relative to the overall installed generation capacity, the more challenging it becomes. It is important to note that power systems from around the world all differ. One utility might easily cope with 10% of variable renewables while to another 10% of variable renewables might be virtually impossible to handle.

From the list of renewable energy technologies to be developed before 2016 shown in Table 3, the majority of the capacity allocated by the DoE was allocated to onshore wind and solar photo voltaic (PV) technologies, which are the kind of RE technologies requiring special effort to integrate into an electrical network.

According to the International Energy Agency, power output from solar PV plants is never less than 20% of its rated capacity during daylight. One of the main contributing factors towards this phenomenon is the fact that solar PV plants can produce electrical energy even under cloud cover (International Energy Agency, 2011). This provides a measure of certainty when it comes to electrical energy generation from solar PV. It is unlikely however, that wind forecasts will ever be fully accurate and for this reason the remainder of this research will focus on wind generation.

Unpredictability of wind generation

Relatively small variations in frequency can cause damage to electrical equipment. It is thus of high priority for any Transmission System Operator (TSO) to continuously balance supply and demand in order to maintain the frequency within the statutory limits.

Although the fluctuations are greater in the case of wind power, by nature wind and solar energy are stochastic with the consequence that power output from these generators cannot be scheduled in advance with great accuracy. These generators are non-dispatchable implying that under normal operating conditions the generator makes the primary dispatch decision for the generating unit or facility.

In the case of wind generation, while generating and at wind speeds of between 5 meters per second and 15 meters per second, a single unpredicted meter per second increase or decrease could cause the wind turbines to feed a significantly altered amount of electrical energy, plus or minus, into the system. If these RE sources are not controlled correctly this can lead to grid instability and even failure.

Self-reliance of Eskom

Most European utilities making use of non-dispatchable generation technologies rely heavily on interconnections with their neighboring utilities. For Eskom this is not an option. As mentioned earlier, Eskom supplies 95% of South Africa's electrical energy and more than 40% of Africa's electrical energy.

From an electrical network point of view, the Southern African Power Pool (SAPP) Interconnected Power System (IPS) is formed by Eskom, Nampower, Botswana Power Corporation (BPC), Eléctricidade de Moçambique (EDM), Swaziland Electricity Board (SEB) and Lesotho Energy Corporation (LEC) and operates as one control area. As the dominant energy supplier of the SAPP IPS, Eskom does not have the luxury to rely on its interconnections with these utilities from neighboring countries for balancing the electrical energy.

Types of demand

Figure 2 shows the typical daily profile of South Africa's electrical energy demand. A fairly predictable curve that peaks at breakfast and supper times can be seen. During late evenings and early mornings demand for electrical energy is relatively low but never below a certain 'base.' The two peak periods in the daily system load profile, i.e. the morning and evening peaks, occurs at different times of the day during winter and summer months. In winter, identified as May to August, the morning peak occurs from 06:00 to 09:00 and the evening peak occurs from 17:00 to 20:00. In summer, covering the remainder of the year outside winter, the morning peak occurs from 09:00 to 12:00 and the evening peak from 18:00 to 21:00 (Smith *et al.*, 2012).

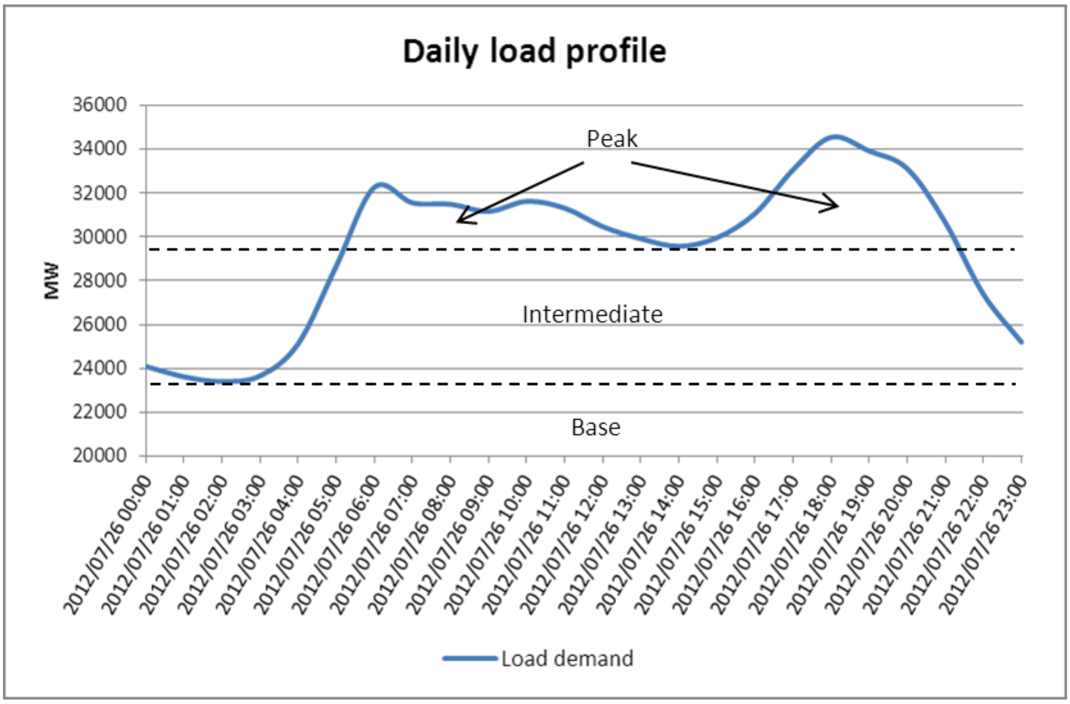

Figure 2: Typical daily load profile

Figure 2 also illustrates the three different types of demand, viz. base, intermediate and peak load. Every utility must have base load power plants, intermediate power plants, and peak power plants to operate reliably and efficiently.

Base load power plants produce continuous, reliable and efficient power at low cost. It is normal for them to take a long time to start up and they are relatively inefficient at less than full output. Base load plants run at all times throughout the year except during repairs or when they are scheduled for maintenance. According to Cordaro, the rule of thumb for a typical power system is to have base load power of 35% to 40% of the maximum load during the year (Cordaro, 2008).

Demand spikes are handled by intermediate or peak power plants, which normally are smaller and more responsive to changes in demand. Peak load power plants provide power during periods of peak demand. They are highly responsive to changes in demand and can be started up in a short space of time. In comparison with base load plants, peaking plants are very expensive to operate relative to the amount of electrical energy they produce and the cost of fuel to power them. Due to their size, however, they are less expensive and easier to build. Peaking plants are most often natural gas combustion turbine plants, but some do run on light oil.

Intermediate load plants are supposed to fill the gap between base load and peaking plants. According to Cordaro, from a cost and flexibility point of view, they typically operate between 30% and 60% of the time. Intermediate plants are larger than peaking plants and consequently their construction costs are higher. They, however, run more efficiently than peaking plants.

In most countries, as is also the case in South Africa, base load power stations consist out of nuclear and coal. When it comes to peaking plants, South Africa makes use of its hydro stations and pumped storage schemes. The OCGTs and gas units are part of Eskom's emergency resources whereas in other countries those types of generation form part of the peaking resources. It is standard practice for Eskom's thermal coal stations to ramp up and down and to also contribute towards spinning reserves. Eskom's coal fired power stations consequently act as both base load stations as well as intermediate power plants.

Load following of generators

The total load of the Eskom network gets forecasted very accurately, which enables Eskom's TSO to adjust generation output on the hour to follow the load with great accuracy. Until now, balancing reserves has only been a small fraction of the total amount of generation and has been achieved mainly by means of primary and secondary frequency control. (A discussion of primary and secondary frequency control follows in paragraph 2.2). Accurate load forecasting, good reserves management and adequate performance of these balancing reserves have so far enabled Eskom to control the frequency within the statutory limits with relative ease. Through introducing non-dispatchable RE into the generation mix, Eskom's TSO will not be able to simply just follow the load as has been the case in the past.

Energy dumping

The reduced load conditions during night times are not ideal and from a System Operator's point of view a flat load profile is preferred. During these reduced load periods there is excess generating capacity available on the system. The problem is exacerbated by the fact that thermal generation has a minimum practical output for stable operation, which may be higher than the available system load under certain circumstances. To smooth out the load profile and to help alleviate this problem Eskom makes use of its pumped storage schemes. Reversible pump/turbines use electrical energy to pump water from a lower to an upper reservoir during off-peak conditions throughout the night. During peak demand, water runs back into the lower reservoir through the turbines, generating electrical energy as required.

Although South Africa's coal fired power stations have been designed to run as base load stations and cannot in general quickly be brought back to service once off line, some of the units have a capability known as two-shifting to help with the much needed energy dumping. Two-shifting is where units, which can, are taken off load and are brought back on load within a short space of time, typically within eight hours. This is achieved by special measures to maintain temperatures in the boiler and turbine. There have been times recently however, where due to technical problems Eskom's normal two-shifting units were not able to two-shift. During these times Eskom's System Operator was forced to reduce its electrical energy imports from Mozambique, which is the cheapest energy available on the system. Because electrical energy generated through RE sources will be on a take-or-pay basis and because normal base load stations take rather long to return to service once off-line, adding wind generation during minimum loading conditions might force Eskom to reduce its imports from Mozambique on a regular basis.

In view of the above, it follows that it is necessary and timely to research how the integration of non-dispatchable RE generation, from the first two rounds of the DoE's RE IPP Procurement Programme, into the South African electrical network will affect the use of Eskom's current generating resources. It should be determined whether the resources that previously helped to balance the variability in demand will still be adequate to balance variability now in both demand *and* supply.

1.7 Research objectives

The resources that previously helped the power system to cope with variability in demand now need to be assessed to determine whether they will still be adequate to cater for variability in both demand and supply.

The objectives of the research are to:

- Determine whether Eskom's current regulating reserve requirements will be adequate to also cater for the integration of variable RE generation into the South African electrical network according to the capacities allocated by the DoE in the first two rounds of the RE IPP Procurement Programme;
- Determine whether geographically spreading the wind farms will have a smoothing effect as compared to wind farms that are clustered closely together;

- Determine whether the contribution from RE generation would have provided significant benefit during the past at times when Eskom was running short on generation, and
- Determine whether the RE generation would have contributed to unwanted energy during times when Eskom was running with surplus generation.

1.8 Dissertation outline

Chapter 2 represents the literature study and investigates how Eskom controls the frequency during normal and abnormal conditions. It also looks at Eskom's 2012 instantaneous reserve studies for present requirements for both winter and summer conditions. Lastly, it looks at a case study for how Denmark approached wind integration into their electrical network.

Chapter 3 discusses the wind data that will be used to convert wind speeds into corresponding hypothetical electrical power outputs according to the installed capacities of the proposed wind farms from bidders who successfully bid in round 1 and round 2 of the RE IPP Procurement Programme. Historical Eskom generator output data to be used, sourced from Eskom's Phoenix database at National Control, will also be discussed.

Chapter 4 discusses the historical Eskom data for the months of December 2011 and July 2012. Actual historical Eskom generation data, historical utilisation of emergency resources and low frequency events that occurred on the network are investigated and analysed. In chapter 4 the wind speed data, presented in chapter 3, is analysed in terms of the equivalent electrical power output.

Chapter 5 investigates the potential wind generation in conjunction with historical Eskom generation data. The effect the wind generation would have had on Eskom's actual generation resources had wind been a part of the generation mix are analysed in this chapter.

Chapter 6 concludes the research and gives some recommendations.

Chapter 2

This chapter investigates how Eskom controls the frequency under normal and abnormal conditions. It looks at Eskom's current instantaneous reserve requirements and studies the approach Denmark followed for integrating wind energy into their network.

Chapter 2 : Literature Review

2.1 Introduction

Chapter 2 represents the literature study. Due to the fact that non-dispatchable generation sources will become part of Eskom's generation mix, supply will become variable and less certain. Consequently frequency control will become more challenging.

This chapter investigates how Eskom controls the frequency during normal and abnormal conditions. It also looks at Eskom's 2012 instantaneous reserve studies for present requirements for both winter and summer conditions. Lastly, it looks at how Denmark integrated wind generation into the Danish electrical network.

2.2 Eskom's control of system frequency under normal and abnormal conditions

2.2.1 Introduction

Operating reserve is essential when it comes to system operations and control. Whenever there is a disturbance on the network that has an effect on the frequency, one of the important functions of operating reserves is to provide adequate generation support to restore the frequency back to within the acceptable range (Chang-Chien *et al.*, 2007).

According to the South African Grid Code (2008), "Operating reserves are required to secure capacity that will be available for reliable and secure balancing of supply and demand within ten minutes and without any energy restrictions. Operating reserves shall consist of instantaneous reserve, regulating reserve and ten minute reserve."

2.2.2 Operating reserves

Frequency control goes hand in hand with the availability of operating reserves and Eskom's operating reserves are made up of instantaneous reserves, regulating reserves and 10-minute reserves as per the South African Grid Code requirements.

Primary frequency control is the automatic adjustment of a generator output in response to deviations in the system frequency, by means of the local governor control system of the turbine. Generating reserves in this category are known as instantaneous reserves.

Secondary frequency control is performed via automatic or manual control of generator outputs to provide a balance between the supply and demand in a control area. Generating reserves in this category are known as regulating reserves.

Generating capacity (synchronised or not) or consumer load that can respond within 10 minutes when called upon is known as 10-minute reserves. The purpose of this reserve is to restore instantaneous and regulating reserves to the required level after an incident. A requirement for 10-minute reserves is that it must be available for at least two hours.

In addition to instantaneous reserves, regulating reserves and 10-minute reserves there are also emergency reserves and supplemental reserves, but they are not part of Eskom's operating reserves.

2.2.3 Generator ramp rates

The automatic control of Eskom's generator outputs is performed by the Automatic Generation Control (AGC) system at Eskom's National Control Centre.

For a thermal generating unit to qualify for AGC the unit must demonstrate to the Ancillary Services department within Eskom that the resource is capable of performing regulation. According to Eskom's procedure SPC46-7, *"Certification and performance monitoring of generation reserves"*, one of the qualifying criteria for such a unit is to have a ramp rate that exceeds 10 MW per minute in each direction for a 600 MW unit and 1.67% of MCR per minute for other sized units (Dean, 2009).

The response rates for hydro generators are much faster and depending on the availability of water these generators can be used for both base load and peak load generation. According to Eskom's procedure SPC46-14, *"Operation of Drakensberg pumped storage scheme"*, the time it takes for a unit at Drakensberg from standstill to full load of 250 MW is three minutes, giving it an upwards ramp rate of 83.3 MW per minute. These units are able to go from pumping to full generating output in a period of seven minutes, which results in a load difference of 500 MW (Dean, 2008).

2.2.4 Definition of normal and abnormal conditions

According to Eskom's procedure SOPPC0008, *"Control of system frequency under normal and abnormal conditions"*, normal conditions are defined as (Ntusi, 2011):

a) The immediate demand can be met with the available scheduled resources and a minimum operating reserve of 600 MW is available at all times, excluding utilising any emergency resources; and
b) The frequency is not less than 49.8 Hz for longer than 10 minutes; and
c) The frequency is within the range of 49.5 Hz to 50.5 Hz; and
d) The interconnection is intact; and
e) There is no security and safety contravention.

If any of the above mentioned conditions are not met, the system is considered to be in an abnormal condition.

2.2.5 Contracted load dispatch schedules

The contracted load dispatch schedule is the hourly-integrated schedule as determined by the Generation Scheduler through the Generation Scheduling Process. The main objective of Eskom's Generation Scheduling Process is to optimally plan generation usage in such a manner that it will ensure the safety of plant and personnel, system integrity and continuity of supply (Binneman, 2012). Units are scheduled according the Economic Dispatch Principle (EDP), which states that the cheapest unit will run first. The schedule should adhere to all reserve requirements as specified in Eskom's procedure SPC 46-2 *"Short term energy reserve procedure".* These requirements are (Ntusi, 2011):

- Sufficient instantaneous reserve is required so that in normal conditions the largest single contingency (i.e. a Koeberg unit) will not result in a frequency lower than 49.5 Hz, and the most credible multiple contingency will not result in a frequency below 49.0 Hz. In addition, sufficient instantaneous reserve is required on generators so as to avoid the high frequency limit of 50.5 Hz being exceeded.
- Regulating reserve has to cater for the normal expected deviation of generation from instantaneous demand and the deviation of instantaneous demand from the hourly integrated demand (i.e. the peak within the peak hour). Regulating reserve should also cater for the largest 10-minute change in demand under normal conditions.

- The minimum requirement for 10-minute reserve to be contracted day-ahead is based on the need for the generation loss of the largest unit (a Koeberg unit) to be replaced by the regulation plus 10-minute reserve.
  In addition, the optimum amount of 10-minute reserve may be calculated from the optimum scheduled operating reserve. The required operating reserve is normally re-calculated annually or whenever substantial changes occur in plant outage rates or emergency resource availability. The 10-minute reserve requirement is then the optimum scheduled operating reserve less the instantaneous reserve less the regulation reserve.

To ensure smooth running of the system the generation schedule for the next day is submitted to the control room loading desk before 14:00 the day before the schedule implementation.

2.2.6 Dispatch under normal conditions

Under normal conditions load dispatch is performed according to the contracted load dispatch schedule. Supply is balanced with the demand and the frequency is maintained within 49.85 Hz to 50.15 Hz by means of primary and secondary frequency control.

The controller keeps to the load dispatch schedule as far as possible and to help the controller making decisions, a loading order of units sorted in energy price order is available on TEMSE. (TEMSE is the SCADA system used at Eskom National Control and is an acronym for Transmission Energy Management System Evolution). The 10-minute reserve resources are included in this list. Operating reserve levels should be maintained as specified in Eskom's procedure SPC 46-2 *"Short term energy reserve procedure".*

The controller must ensure as far as possible that the regulating up and down reserves do not drop below the current minimum requirements of 600 MW. If either instantaneous or regulating reserves drop below the required levels, on-line units can be re-contracted to restore these reserves or cold reserve units (hydro or pumped storage) dispatched. If the real-time spinning reserve drops below 600 MW then sufficient off-line 10-minute resources should be called up to return the reserves to the required levels according to the energy price merit order. The off-line 10-minute reserves may include pumped storage or hydro plant.

2.2.7 Operation during abnormal conditions

When an abnormal condition has occurred as defined in 2.2.4, immediate corrective actions must be taken until the system frequency has returned to within the dead band of 49.85 Hz to 50.15 Hz and the condition is back to normal. The corrective actions include both supply and demand side options. Where possible, warnings must be issued on expected utilisation of any emergency resources.

The order in which emergency resources are used changes from time to time based on contractual arrangements, changes in prices or resource availability. The emergency resource deployment merit order is issued by the generation scheduler each time a change occurs.

2.2.7.1 Emergency Level 1 warning and supplementary reserve call up

If the controller finds that the expected real-time operating reserve over the coming peak is likely to fall to or below zero, and time remains to call up supplementary reserve, sufficient reserve should be called up for capacity to meet the peak load. If a shortage is still expected then an Emergency Level 1 (EL1) warning must be issued giving the time during which the shortfall is expected. (EL1 is extra capacity from generating units over and above their maximum continuous ratings, still within the unit’s safe operating limits).

2.2.7.2 Emergency Level 1 in force

After calling up all available 10-minute reserves and supplemental reserves and the spinning reserve is likely to fall to or below zero in the next ten minutes, and the load is still increasing, then EL1 must immediately be declared at sufficient stations specified in the emergency reserve deployment merit order to maintain the frequency at 49.85 Hz to 50.15 Hz throughout the peak. The controller should, when applicable, stagger the call-up of each station to ensure that the frequency does not exceed 50.15 Hz. The stations requested to go to EL1 should as far as possible be chosen in the order of EL1 prices submitted by the power stations, starting with the cheapest station. This order may change to assist in maintaining a reliable network.

2.2.7.3 Shedding of interruptible load and use of other emergency resources

Eskom has granted BHP Billiton an electricity tariff at their Bayside, Hillside and Mozal Aluminium smelters that is linked to the price of aluminium and the R/$ exchange rate. Their tariff can be lower or higher than the normal electricity tariff, depending on the R/$ exchange rate. To compensate for this concession and when needed, Eskom is allowed to interrupt load at the Bayside, Hillside and Mozal smelters according to agreed terms and conditions (Sebela, 2011).

One of the benefits is that the interruptible load can quickly be brought into effect.

Interruptible load may be shed as follows (Sebela, 2011):

a) If EL1 is in force and the frequency falls steadily below 49.8 Hz and the load is still increasing or generation is decreasing, sufficient interruptible load must be shed until the frequency is within the acceptable limits of normal operation (49.85 Hz to 50.15 Hz). The controller should, when applicable, stagger the shedding of each load to ensure that the frequency does not exceed these limits.
b) If the frequency falls rapidly below 49.5 Hz and does not recover within one minute; and no hydro or pumped storage units are about to synchronise, sufficient interruptible load must be shed until the frequency is within the acceptable limits.

To avoid using interruptible loads, the frequency must not be allowed to slide. The order of emergency resources shall be dispatched by National Control according to the current Emergency Resource Deployment Merit Order.

The Emergency Response Deployment Merit Order also provides for transmission related emergencies, such as incipient voltage collapse or line overloads.

2.2.7.4 Manual load shedding and SAPP emergency

If all emergency resources have already been utilised and the frequency continues to slide below 49.5 Hz, then load curtailment and manual load shedding may be utilised. Sufficient shedding is performed so as to allow the system frequency to return to within the dead-band.

A SAPP Emergency must be declared before load shedding commences.

2.2.7.5 Automatic under-frequency operation

Some automatic under-frequency operations may occur based on the severity and duration of under-frequency conditions. These operations include the suspension of AGC, auto-start of pumped storage, auto-start of gas turbines, activation of automatic under-frequency load shedding schemes and the tripping of interconnected tie-lines.

2.3 Eskom 2012 instantaneous reserve studies

2.3.1 Introduction

Instantaneous reserves, which form part of the operating reserves, are needed to arrest the frequency at acceptable limits following a contingency, such as a unit trip or a sudden surge in load. The requirements on instantaneous reserves are to be fully activated within ten seconds and to be maintained for at least ten minutes (National Energy Regulator of South Africa, 2008).

2.3.2 System Operator Grid Code requirements

The South African Grid Code requirement on the System Operator is to keep the frequency above 49.5 Hz following a credible single contingency and above 49.0 Hz following credible multiple contingencies. A credible single contingency is regarded as losing a Koeberg unit at full load while credible multiple contingencies is regarded as losing 1800 MW of generation. This is representative of losing three typical coal fired generating units or the loss of the Cahora Bassa in-feed (National Energy Regulator of South Africa, 2008).

2.3.3 Objective and methodology of studies

The purpose of Eskom's instantaneous reserve studies was to assess the instantaneous reserve (IR) requirements for the Eskom power system for 2012 covering both the winter peak and summer off-peak periods representing worst case scenarios on both extremes. The aim was also to recommend the optimum frequency threshold and time delay settings for demand market participation (DMP) and to evaluate the impact of increasing DMP while reducing IR (Mtolo & Edwards, 2012).

Eskom introduced DMP in 2003 due to the fact that it no longer had excess generation capacity. DMP gives customers the opportunity to bid any flexible demand onto the Eskom power pool to be used when the system is in an abnormal condition. In reality these customers bid their load reduction onto the pool and not their generation capacity. High-resolution measurement equipment is then used to verify that customers did indeed react as per the contractual requirements (Surtees, 2005).

The instantaneous reserve studies were performed utilising the existing generation mix within Eskom as specified in Table 1. A full model of the Eskom transmission network was used with all the generator governors modelled in detail. The load was modelled as being frequency responsive with load frequency characteristics (LFC) of 3% and 4% assumed for winter and summer, respectively based on historical performance. DMP and under-frequency load shedding (UFLS) were included in the system model whereas the impact of imports from neighbouring countries such as Zimbabwe and Botswana was not considered.

The frequency performance was studied for the loss of a Koeberg unit at full load as well as for the loss the HVDC in-feed at Apollo convertor station.

The under-frequency performance for various values of IR, DMP load with frequency threshold and time delay settings were considered with the intention of maintaining the system frequency above 49.5 Hz as stipulated in the Grid Code (National Energy Regulator of South Africa, 2008). The effect on UFLS (i.e. 1st stage set to 49.2 Hz after 0.3 seconds delay) was taken into account specifically to cater for large incidents that result in low system frequencies i.e. below 49.2 Hz.

The IR performance was measured against (1) as stipulated in the certification and performance monitoring of generation reserves report (Dean, 2009):

$$AMS = 0.5 \times (Maximum\ Response + Sustained\ Response) \quad \text{[MW]} \qquad (1)$$

Where,

AMS = Average of maximum sustained power [MW]

Maximum Response = maximum sent-out loading over the first 10 seconds after the start of the incident minus the initial loading level [MW]

Sustained Response = average response during the period starting 10 seconds after the start of the incident and ending 10 minutes after the start of the incident, or when the frequency rises above 49.85 Hz, whichever occurs first. The start of the incident is regarded as the time when the frequency falls below 49.75 Hz for longer than 4 seconds. [MW]

Figure 3 shows a typical governor and frequency response following a loss in generation. The overall system performance quantified in terms of the turning and settling frequency.

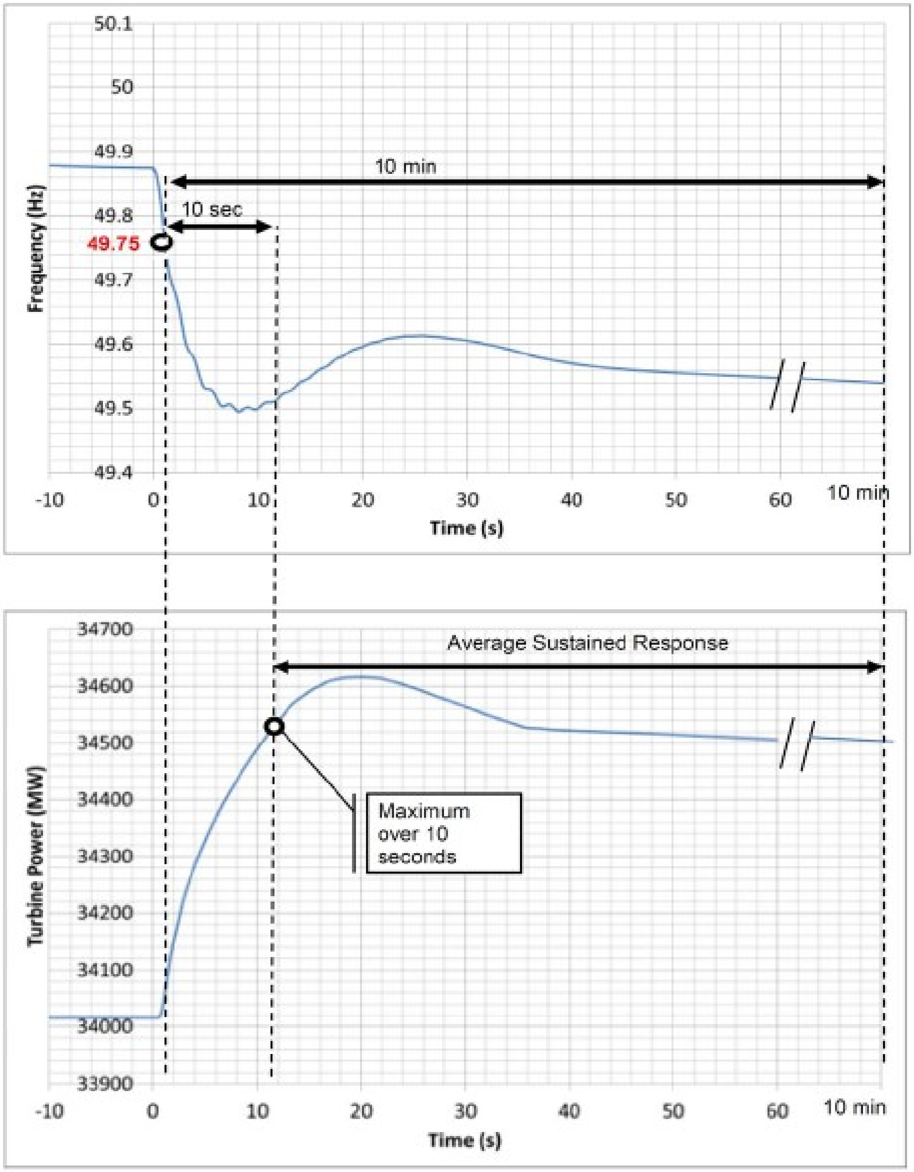

Figure 3: Typical frequency and governor response (Mtolo & Edwards, 2012)

Table 8 details the base cases used for the winter peak and summer minimum studies. The DMP for these studies were selected as 120 MW with current settings of 49.65 Hz with a 4 second time delay as per the current settings and performance.

Table 8: Base case details for winter peak and summer minimum scenarios

	Winter Peak	Summer Minimum
Total load	34 790 MW	21 089 MW
Total generation	35 539 MW	21 447 MW
Instantaneous Reserves	600 MW	700 MW
DMP (49.65 Hz, 4 seconds)	120 MW	120 MW

The impact that the DMP settings have on the network frequency performance was evaluated as per details shown in Table 9.

Table 9: DMP- combinations for winter peak

Scenario	Details
Loss of a Koeberg unit at full load	Load shedding of 300 MW of DMP at 49.65 Hz after 4 s delay
	Load shedding of 120 MW of DMP at 49.65 Hz after 1 s delay
	Load shedding of 300 MW of DMP at 49.65 Hz after 1 s delay
	Load shedding of 120 MW of DMP at 49.75 Hz after 4 s delay
	Load shedding of 300 MW of DMP at 49.75 Hz after 4 s delay
	Load shedding of 120 MW of DMP at 49.75 Hz after 1 s delay
	Load shedding of 300 MW of DMP at 49.75 Hz after 1 s delay

The effect on the system frequency performance with reduced amounts of IR in combination with variations in DMP was evaluated as per details shown in Table 10.

Table 10: IR and DMP- combinations for winter peak and summer minimum

Contingency	IR (MW)	DMP (MW)
Loss of a Koeberg unit at full load during winter	600	0
	500	400
	300	600
	80	800
Loss of a Koeberg unit at full load during summer	770	0
	700	120
	600	300
	500	400
	400	500
	200	700
	100	800

Table 11 shows the details for the multiple unit scenarios that were studied and analysed with an IR of 600 MW. The DMP amounts and timer settings were varied to gauge the effect on the overall frequency performance.

Table 11: Scenarios for multiple unit trips

Scenario	Details
Loss of HVDC (Apollo)	Load shedding of 120 MW of DMP at 49.65 Hz after 4 s delay
	Load shedding of 300 MW of DMP at 49.65 Hz after 4 s delay
	Load shedding of 120 MW of DMP at 49.65 Hz after 1 s delay
	Load shedding of 300 MW of DMP at 49.65 Hz after 1 s delay
	Load shedding of 120 MW of DMP at 49.75 Hz after 4 s delay
	Load shedding of 300 MW of DMP at 49.75 Hz after 4 s delay
	Load shedding of 120 MW of DMP at 49.75 Hz after 1 s delay
	Load shedding of 300 MW of DMP at 49.75 Hz after 1 s delay

The effect of reduced IR with variations in DMP for multiple unit trips was evaluated as per details shown in Table 12. In this case the DMP settings were kept to 49.65 Hz with a time delay of one second.

Table 12: IR and DMP- combinations for winter peak

Contingency	IR (MW)	DMP (MW)
Loss of HVDC (Apollo)	600	0
	500	400
	300	600
	80	800

2.3.4 Conclusions for Eskom's 2012 instantaneous reserve studies

The following recommendations and conclusions were made based on the findings of Eskom's instantaneous reserve studies for 2012 (Mtolo & Edwards, 2012):

- The instantaneous reserve requirements were determined to be a minimum of 600 MW and 700 MW for winter and summer respectively, taking into account a realistic amount of DMP to maintain the system frequency above 49.5 Hz for the largest single unit contingency.
- Frequency performance during the largest single unit contingency is improved with increased amounts of DMP and reduced time delay settings where the governors' response does not meet the minimum recommended requirements. It was therefore recommended that the time delay settings for DMP relays be reduced to one second.
- During multiple unit contingencies or large deficit trips, above a total of 1400 MW, the system frequency decline is fast and activates the first UFLS stages. DMP settings in this case do not play a significant role in the turning frequency, but do marginally contribute to improved settling frequencies for the case where the recommended governing is maintained.
- The effects of reduced IR on frequency performance for both single and multiple unit contingencies were evaluated. In the case of the most onerous single contingency, a reduction in IR leads to a disproportionate increase in DMP requirements to maintain the turning frequency above the 49.5 Hz threshold. In the case of a loss of more than 1400 MW, the UFLS scheme plays a significant role in arresting the frequency decline and different IR-DMP combinations were shown not to lead to large variations in the overall frequency performance for the cases considered.

2.4 Wind energy – the case of Denmark

2.4.1 Introduction

Denmark has a well-developed electrical energy industry, which has evolved from sixteen primary generating stations in the mid-1980s to thousands of embedded generators including CHP (combined heat and power) and WTGs (wind turbine generators). The majority of Denmark's electrical energy is generated from fossil fuel plants within Denmark. During wet years, a significant component of Denmark's electrical energy is also sourced from Nordic hydropower. Denmark's total maximum system demand is roughly 6500 MW, with a valley load of about 3500 MW. Generation is categorised into three main types; large scale CHP stations with a total capacity of 7200 MW, small scale CHP with a total capacity of 2500 MW and Wind with a total capacity of 3800 MW. This puts Denmark's total installed capacity at 13.5 GW

(Lund, 2011). That means that even without the installed capacity of the wind generators, Denmark has a surplus capacity of 3200 MW to give them a reserve margin of 49.23%.

2.4.2 Overview of the Danish electrical network

Denmark is split into two main transmission areas, western and eastern Denmark. The Danish network is interconnected with Sweden, Germany and Norway, all of which have much larger power systems. These interconnections play a major role in the Danish network since Denmark has no electrical energy storage within its electrical system. Power can flow in any direction, limited only by the capacity of the interconnectors.

The interconnection to Sweden consists of two 400 kV cable connections, two 132 kV cable connections and two 250 kV DC connections with a total capacity of about 2440 MW. The interconnection to Germany is one 400 kV DC, one 400 kV, two 220 kV and one 150 kV AC connections with a total transmission capacity of 2100 MW. The interconnection to Norway consists of two 250 kV and one 350 kV interconnections with a total transmission capacity of 1040 MW (Lund, 2011).

The total transmission capacity through the interconnectors is determined by congestion in the surrounding grids and is normally 1500 MW in the southbound direction and approximately 950 MW in the northbound direction. When Germany increases demand, Norway and Sweden provide supply through Denmark and when Germany has excess generation, Norway and Sweden absorb the generation. Also, through Denmark's interconnection to the north, the hydroelectric system of Norway and Sweden are able to balance the intermittent variations in Denmark's wind power, effectively acting as Denmark's electrical energy storage system. To the south, Denmark interconnects with the 600 GW European Union (EU) system, which is more or less a hundred times larger than the Denmark system.

The transfer capacities of the interconnection are shown via the purple arrows in Figure 4.

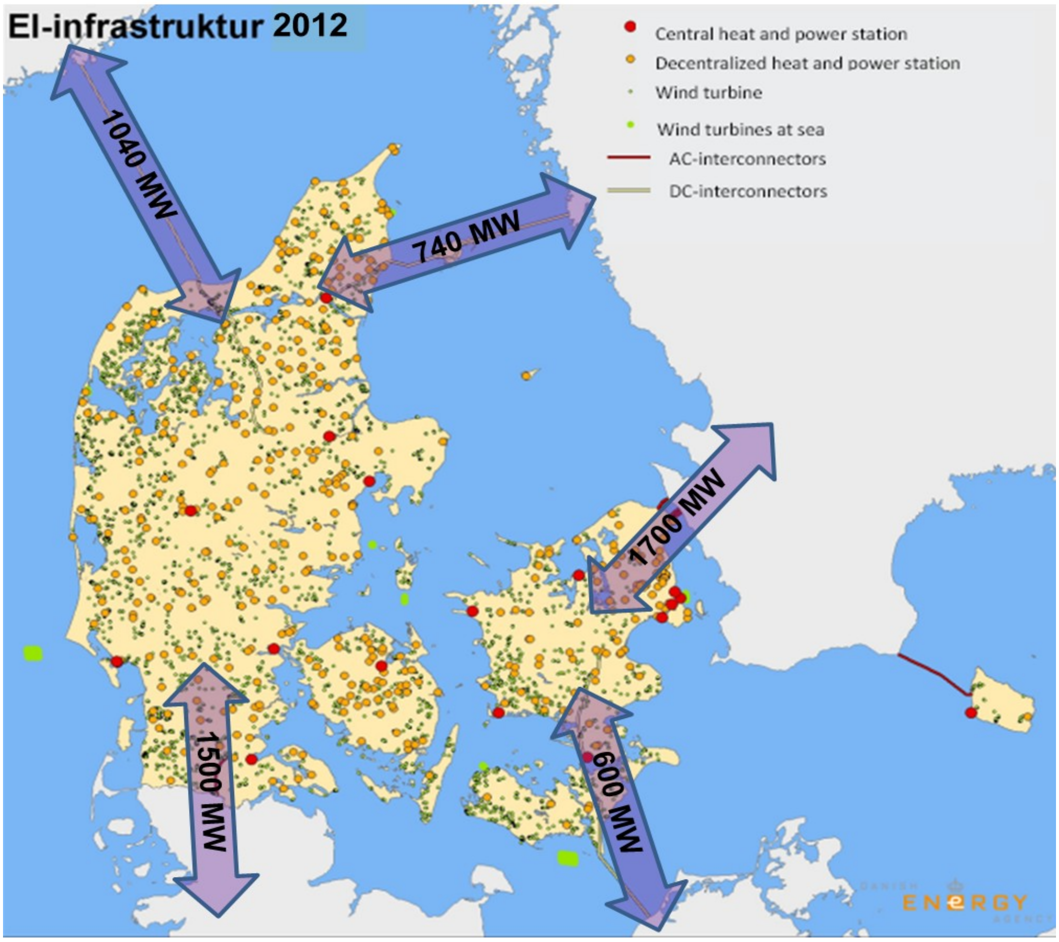

Figure 4: Overview of the Danish power system (Eskom, 2012)

The Danish transmission network is based on high levels of embedded local generation. The red dots on the map of Figure 4 indicate the location of Denmark's sixteen primary CHP stations (totalling approximately 7.2 GW), most of which have been up-graded since 1980. Heat from CHP stations is utilised in the local district heating networks for space and water heating while they generate electrical energy, which makes them thermodynamically very efficient. The brown dots are roughly 600, relatively new, village- scale power plants (having a combined power capacity in the order of 2.5 GW). The green dots represent in excess of 5500 wind turbines (with a total capacity of approximately 4 GW). Of these, roughly 2840 MW of wind capacity are in western Denmark and 960 MW are in eastern Denmark (Lund, 2011).

Transmission and sub-transmission voltages are 400 kV, 150 kV, 132 kV, 60 kV and 50 kV. Due to historical reasons western Denmark's sub-transmission voltage are 150 kV and 60 kV while eastern Denmark utilises 132 kV, 50 kV and 30 kV. The transmission and sub-transmission network is predominately overhead. The 400 kV network will remain overhead conductor, but legislation requires that the 132 kV network is converted to underground cable. MV distribution is mainly 10 kV and is underground cable, with only a very small portion of the MV network overhead conductor. All LV distribution is 400 V three phase underground cables (Lund, 2011).

Denmark has 58 distribution companies with SEAS-NVE operating in eastern Denmark. SEAS-NVE is Denmark's largest consumer-owned energy company and operates as Regional Transmission Operator acting on behalf of the TSO. SEAS-NVE just like most distribution companies in Denmark is responsible for MV and LV (400 V) distribution in smaller towns. However, in bigger towns and cities such as Copenhagen, the distribution company supplies bulk electrical energy to municipal distributors.

2.4.3 Danish wind power

The Danish government's long-term policy goal of being independent from fossil fuels by the year 2050 has contributed to Denmark's fleet of generators being transformed by the addition of many distributed generators. A lot of these distributed generators are wind turbines and it can safely be said that Denmark was the world's first large scale user of wind power. Between 1988 and 2003, the wind generators that Denmark built totalled 3160 MW of wind power capacity with the capacity expansion taking off prominently in the year 1996 (Center for Politiske Studier, 2009). The growth in installed wind power capacity and the percentage of electrical energy supplied by wind in Denmark is shown in Figure 5.

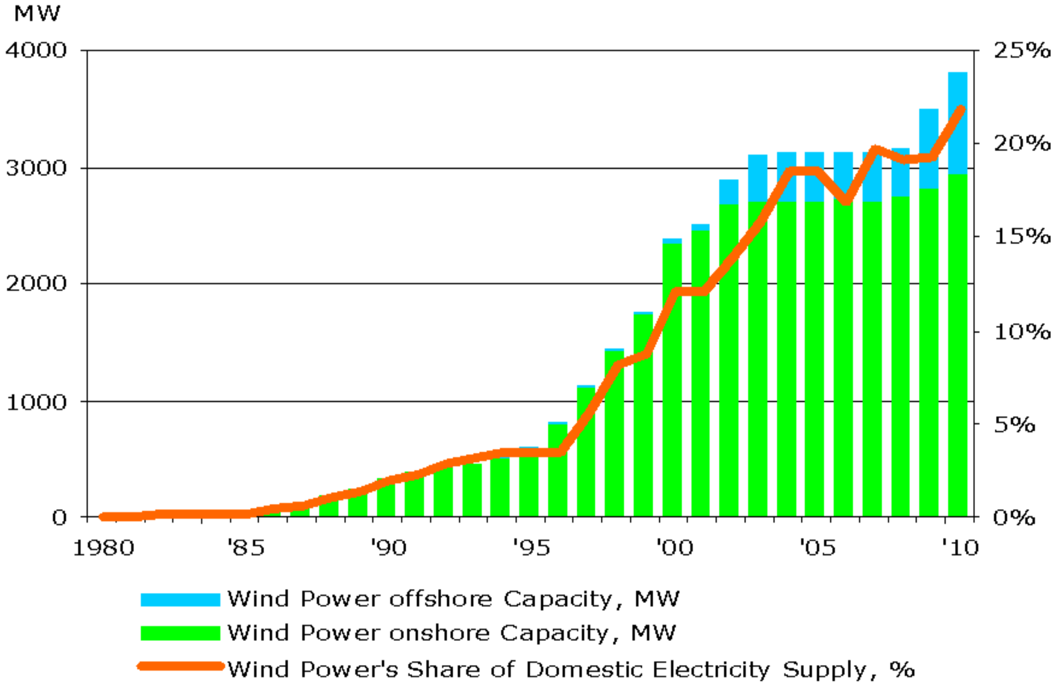

Figure 5: Danish wind power evolution (Danish Energy Agency, 2010)

The target that was set for wind power deployment for the period 2008-2012 required the installation of 1150 MW of new capacity. It was divided between 800 MW of new off-shore wind capacity and 350 MW of new on-shore wind capacity. For the short term target of 800 MW off-shore wind, only the 400 MW Anholt wind farm, planned for December 2012, was not yet commissioned at the time of writing.

Electrical energy generated through wind varies from year to year. About 7.8 TWh was generated from wind in 2010 whereas in 2009 only 6.7 TWh was wind generated (Danish Energy Agency, 2011). Although Demark *generates* about 19% of its demand through wind turbines, it’s not to say that wind power *contributes* 19% of the Nation’s demand for electrical energy. Truth is that a large amount of wind power is exported the same time it is generated. Whenever there are large amounts of wind generated electrical energy within the Danish system, there are invariably large outflows of electrical energy through the interconnectors usually to the North.

Figure 6 shows the wind power output and the net electrical energy flow on the interconnectors to the north for January 2007, which is similar for any “windy” winter month since the year 2000.

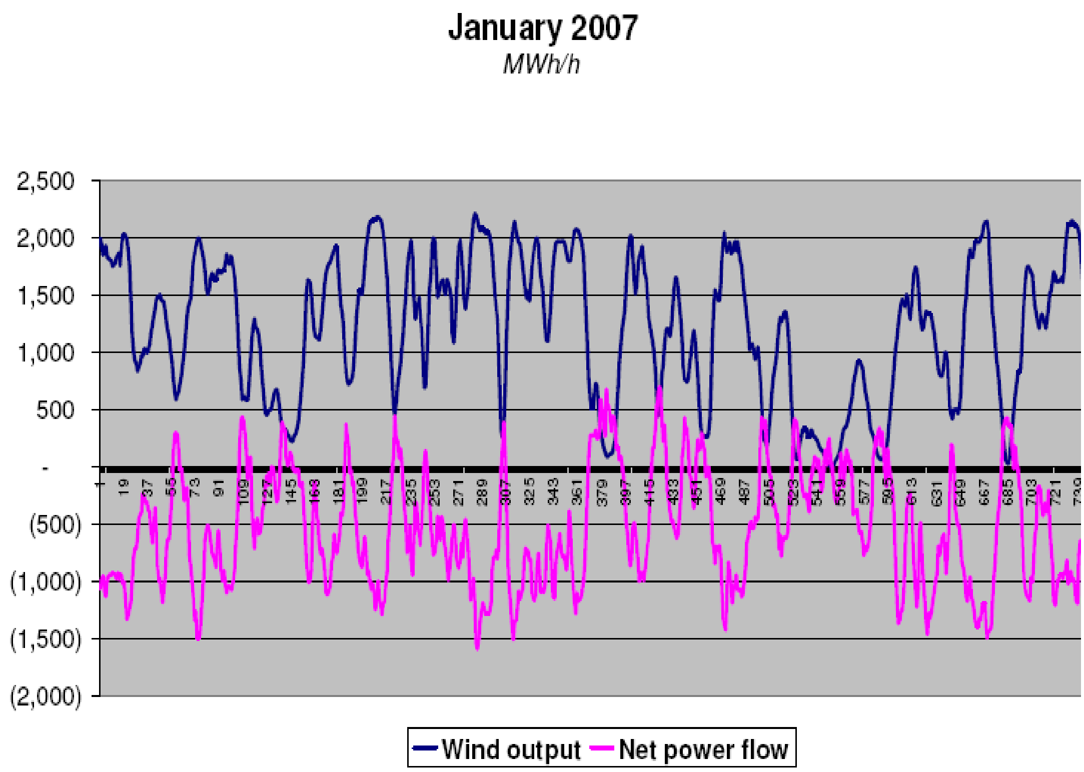

Figure 6: Western Denmark wind output and net flow of electrical energy for January 2007 (Center for Politiske Studier, 2009)

On average there is much less wind during summer periods. Figure 7 shows the wind power output and the net flow on the interconnectors to the north for July 2007. It can be seen that most wind power generated within Western Denmark is consumed within Demark itself with the power being exported whenever wind power exceeds around 500 MW.

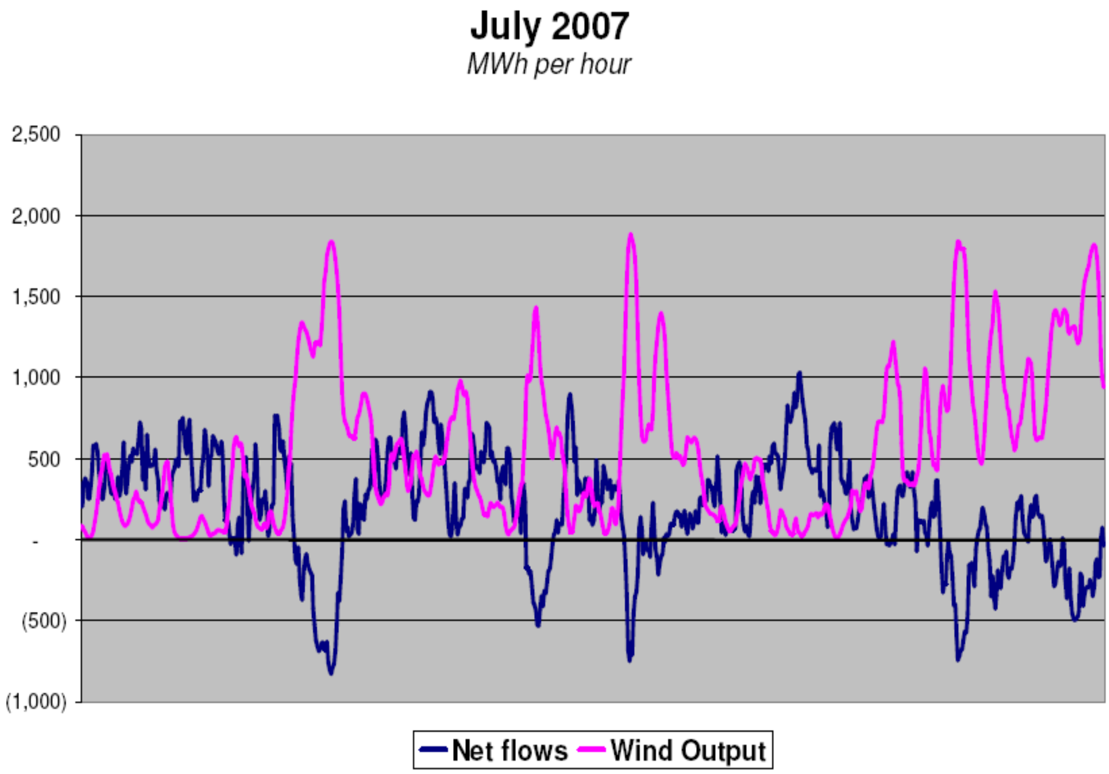

Figure 7: Western Denmark wind output and net flow of electrical energy for July 2007 (Center for Politiske Studier, 2009)

According to the Center for Politiske Studier, West Denmark is the most "wind-intensive" electrical system in the world with approximately 0.9 kW of installed wind power capacity per inhabitant. Germany, with its more than 24 GW of wind power has 0.29 kW per inhabitant with Spain about 0.43 kW per inhabitant. The USA with the world's largest fleet of wind turbines, totalling in excess of 25 GW early 2009, has a wind power capacity of only 0.08 kW per inhabitant (Center for Politiske Studier, 2009).

The capacity factor of Denmark's wind turbine fleet ranges between 20% and 25% per year compared to 16% to 20% per year for Germany. For the USA the wind turbines capacity factor is around 30% (Center for Politiske Studier, 2009).

2.4.4 Reserves management in the Danish power system

To efficiently integrate wind energy into a power system, it is important for the power system to be flexible with regards to available reserve power at any given time. In Denmark reserve management is a market based system with some reserve management done by contract.

Hydro power provides a very flexible balancing resource. Trade between regions provides access to this flexible resource that enables relatively inexpensive short-term balancing of deviations. This benefits the less flexible thermal technologies in the market as well as enabling higher penetration levels of variable generation as it increases flexibility in the system and results in lower prices for electrical energy in the Nordic system.

West Denmark's demand for electrical energy varies between the summer minimum of 1400 MW and the winter maximum of 3700 MW. The regulating reserve that was needed for balancing the intermittent wind generation during 2007 is indicated in Figure 8. It can be seen that it varied between the extremes of -1000 MW and 1500 MW. Relative to the demand, quite a large percentage of balancing reserve was needed.

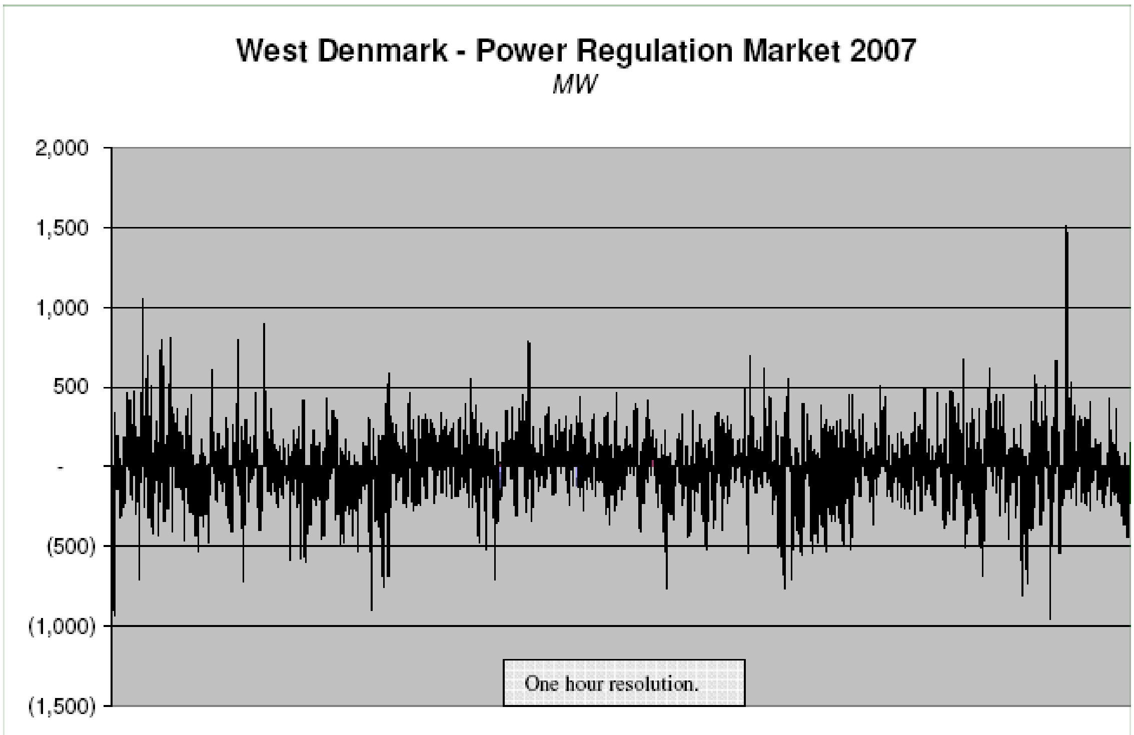

Figure 8: West Denmark regulating reserve usage for the year 2007 (Center for Politiske Studier, 2009)

The reserve power was mainly supplied through the interconnectors and the majority of this was obtained by means of the DC interconnections with Norway and Northern Sweden.

Figure 9 shows the electrical energy production and consumption of West Denmark for January 2007. This was an above average windy month resulting in West Denmark exporting electrical energy basically throughout this winter month. It can clearly be seen how wind generation effects the importing and exporting of power across the interconnectors and how the wind generation substitutes the fossil power. When there is little wind the fossil power compensates and this is appended by imports.

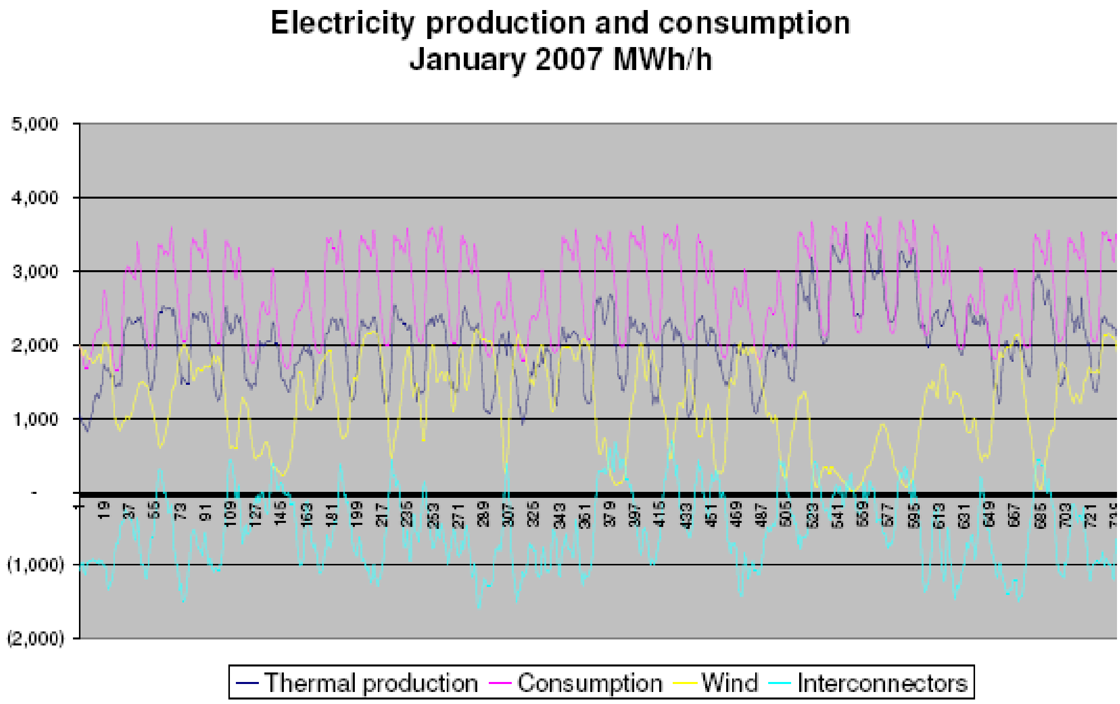

Figure 9: Electrical energy production and consumption for January 2007 (Center for Politiske Studier, 2009)

Figure 10 shows the electrical energy production and consumption of West Denmark for the summer month of July 2007. During this time a significant amount of West Denmark's electrical energy is sourced from Nordic hydropower. The reason for this is that there are plenty of water resources in the Nordic area due to the melted snow and the demand for heat in Denmark is relatively low avoiding the need to run CHP plants within Denmark. It is still clear from Figure 10 that West Denmark exports electrical energy at times when there is plenty of wind.

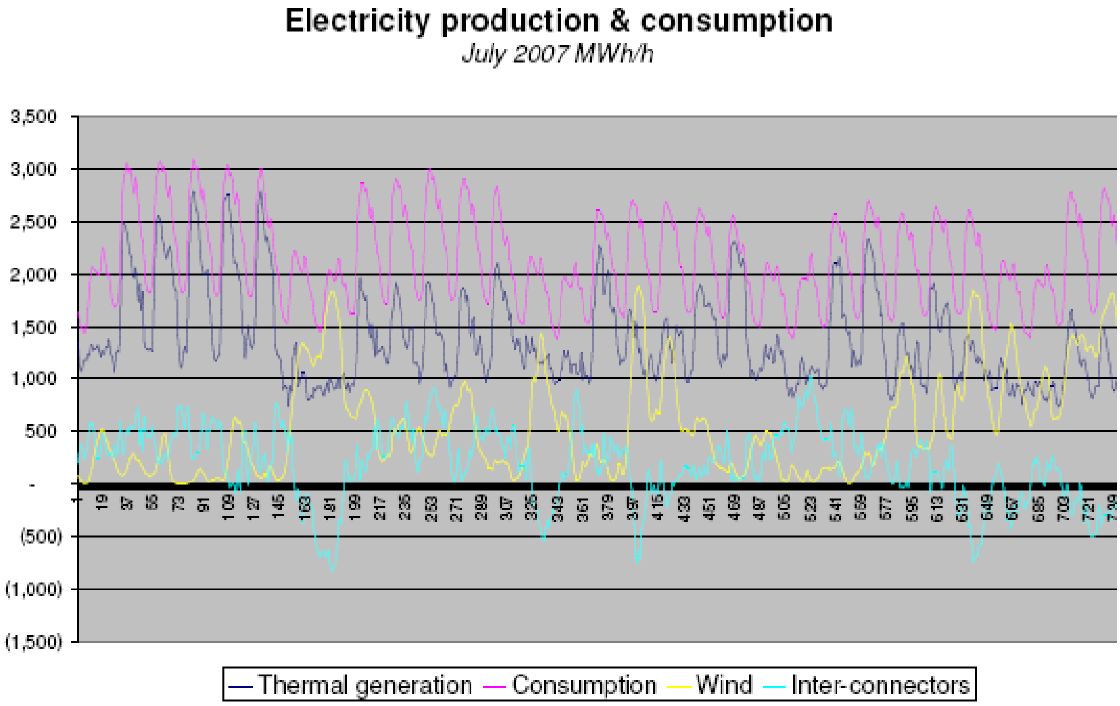

Figure 10: Electrical energy production and consumption for July 2007 (Center for Politiske Studier, 2009)

During 2007, West Denmark exported electrical energy the moment the total wind generation exceeded 300 MW on average (Center for Politiske Studier, 2009).

2.4.4.1 Ancillary services

Ancillary services ensure access to resources that are needed to maintain a balance between demand and supply for stable and reliable power system operation.

In Denmark ancillary services are procured from power generators and electrical energy consumers as well as from neighbouring countries. The ancillary requirements for the two Danish synchronous areas are (Energinet.dk, 2010):

- Primary reserve,
- Secondary reserve,
- Frequency-controlled normal operation reserve,
- Frequency-controlled disturbance reserve,
- Manual reserve, and
- Short-circuit power, reactive reserves and voltage control.

Energinet.dk buys two types of primary reserves, i.e. upward regulation (in case of under-frequency) and downward regulation power (in case of over-frequency). The normal operation reserve must be supplied at a frequency deviation of up to +/-100 mHz, which means a range of 49.9 Hz to 50.1 Hz.

Contrast with Eskom reserves

In Eskom the reserves are on contractual basis and the ancillary requirements are (Ea Energy Analyses, 2011):

- Instantaneous reserve,
- Regulating reserve,
- 10-minute reserve,
- Supplementary reserve,
- Emergency reserve,
- Constrained generation and voltage control,
- Islanding and
- Black start

Eskom's normal operation reserve must be supplied at a frequency deviation of up to +/-150 mHz to give a frequency range of 49.85 Hz to 50.15 Hz.

2.4.5 Danish markets

Denmark participates in the Nordic electricity market called NordPool. Trade between the Nordic countries is driven by the differences in the generation technologies in each country, including hydro, wind, nuclear, fossil fuels and biomass. Each technology has its strengths and weaknesses, which can be offset by trade. The Nordic power system is dominated by hydro power and for this reason trade between countries is mutually beneficial due to annual fluctuations in precipitation. In wet years, there is generally a flow of electrical energy from the north to the south whilst in dry years this flow is reduced or even reversed. There is a correlation between precipitation levels, the cost of electrical energy on the NordPool market and the exchange of electrical energy over interconnectors. This stimulates cross-border trade in the Nordic region.

The NordPool market is made up of a more volatile future and forward market, spot market, intraday market, balancing market, regulating market and bilateral trade. About 75% of all electrical energy exchange is on the spot market. Balancing the system on a daily basis is achieved by use of the spot market, intraday market, regulating market and balancing markets. In addition, trade through import and export, regulation of other generating units and/or curtailing wind power generation as necessary are also used to balance the system. However, since wind power has a lower marginal cost, its curtailment is implemented as a last resort, and then only when the network stability is compromised.

In order to participate on the energy market, potential players are required to register with the Market Operator. Bilateral agreements between generators and consumers are allowed. However, these are purely financial agreements since the power is still traded physically in the spot market before the contract is settled. This is done in order that the system can be balanced by the System Operator through the spot market and because the spot price is the basis for the actual contract. The contracts operate in this way: if a consumer and a generator enter into an agreement for delivery of electrical energy at a set price over a certain period (this is referred to as the strike price), both the consumer and the generator must place bids on the spot market. If the actual price paid in the spot market by the consumer is higher than the strike price, the generator pays the purchaser the difference in cost. Conversely, if the price paid on the spot market is lower than the strike price, the consumer pays the generator the difference. Financial contracts, although uncommon in the Nordic system, help market participants manage risks and are essential in the absence of long-term physical contractual markets.

All market players submit bids on the day-ahead market, or spot market, by 12:00 the day before the first production hour. The spot market is a physical market where prices are determined by balancing supply and demand. The spot market is divided into one hour periods of production and consumption. Once generation bids on the spot market are balanced with demand, the system is then in balance for the following operational day. Price formation on the spot market is determined by marginal pricing and reflects the market price of bringing the last kWh (the one that balances supply and demand) to market for each hour. This creates a merit order for dispatching generating units according to their short term marginal costs. This gives the system operator the insight to use the cheapest and best suited regulation units in an organised way. In addition, having a market pool enables developers to schedule maintenance of wind turbines as needed without incurring penalties, only with loss of revenue. This flexibility is also made possible by the strong cross-border interconnections rendering fluctuations in wind generation a minor concern for Denmark. Each TSO within the market ensures that day ahead planned power transit will not exceed system capacity and orders curtailment of immediate generating units if needed.

In addition to the market for normal operation, the TSO invites bids for ancillary services and regulating reserves through two models. In the first model, the participant may choose to have a specified volume of reserves at a specified period of time available as and when the TSO requires; in which case an activation of the reserve entitles the participant to an availability payment above and beyond the energy payment. The other option is to enter the market whenever the participant sees fit. On activation, the participant is only paid for the energy used. Both models involve entering of bids, activation and settlement of energy payment and imbalances pursuant to this regulation.

By having a detailed knowledge of production, consumption and exchange in advance provides the basis for good grid security calculations, which allow for the grid to be operated closer to the limit, thereby optimising available resources. Practically, when imbalances between demand and production are detected, a market participant with the cheapest bid in the market is activated to increase or decrease generation or consumption until the system is in balance. Generators and consumers that provide regulating power receive the marginal cost of regulating power in the operational hour they were activated. The balancing cost compensated is determined by the market price at the time regulation was provided. Market participants that fail to deliver power compensate the responsible parties that were used for regulation. Based on the frequency and severity of failure to provide the agreed power, the participants may be quarantined from the market for a period of two to thirty days at the discretion of the Market Operator. However, this has not happened to date.

SAPP market

In the SAPP market, trade is largely based on bilateral contracts. Prices have been very low and as such have very little relevance for future prices; particularly for new cross-border sources of supply. This is due to the historical and commercial context under which the contracts were concluded, as well as the development of the regional demand/supply balance over the last few years. In order to balance the system within SAPP, a principle followed is for a member to manually declare an emergency day-ahead, based on a forecasted deficit in their system to market players with potential surplus. In cases of surplus, power is offered to other members that may experience shortages. Power that cannot be traded is dissolved by the interconnected system through communication between System Operators. Prices for power above contracted levels are based on the time-of-use structure. This means that this energy is more expensive during peak periods and the rate is based on an energy source with the highest marginal cost.

2.4.6 Danish electricity tariffs

According to the Organisation for Economic Co-operation and Development (OECD), Denmark is rated amongst the countries with the most strenuous tax burdens on its people (Organisation for Economic Co-orperation and Development, 2011). The price of household electrical energy is not excluded from these taxes and Denmark's household electricity tariffs are amongst the highest in the world. In fact, Denmark's household consumed electrical energy is the most expensive in the EU. On the other hand, electrical energy consumed by the industry is only taxed to a small extent. As a means of comparison in November 2011 the price for household consumed electrical energy was €0.3078 / kWh in comparison with €0.1091 / kWh for industrial consumed electrical energy (Europe's Energy Portal, 2011).

A great portion of the electricity taxes paid by the consumers are used for research and to subsidise the feed-in-tariff system. The feed-in-tariff system is what makes it attractive for all parties to invest in wind generation and is the main reason for the booming Danish wind industry. Power generated through wind is thus subsidised by Government. The level of subsidy is under constant review and depends on political targets set by Government on the one hand and volatile market prices on the other.

A historical trend for the price of electrical energy for West Denmark is shown in Figure 11. Although a persistent increase in the price of electrical energy is noticeable through the years it clearly increased above average during 2003 and 2006 representing the lack of abundant water resources in Scandinavia during those years. On the other hand, the effect of the wet years of 2004 and 2007 is also clearly noticeable with a decline in the price of electrical energy. The hefty increase in 2008 is ascribed to the globally high fossil fuel price of that particular year.

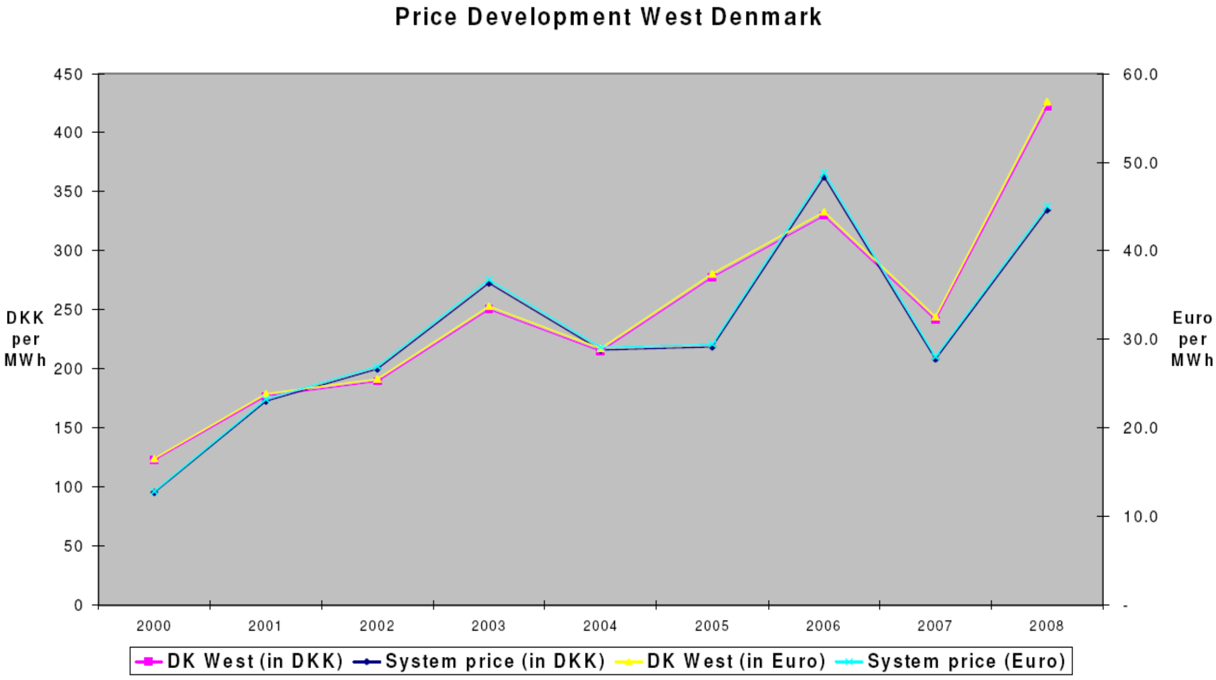

Figure 11: Historical price of electrical energy for West Denmark (Center for Politiske Studier, 2009)

The subsidies to renewable energy generators started in 2001. The subsidies are paid through the TSOs in terms of the Public Service Obligation (PSO) and are sourced from taxes and charges paid by domestic consumers. Subsidies toward wind generation are designed to enable wind farm investors to achieve a payback period of ten years for inland wind farms and fourteen years for offshore wind farms.

The spot market price is dependent on many factors. In 2007 the average market price in West Denmark between times when wind output varied between 0 and 100% was about €13.5 / MWh (Center for Politiske Studier, 2009). There were however almost 100 hours during 2007 when the spot market price for electrical energy was zero. This normally happens at times when there is excess wind and when thermal generators are generating at minimum load, still obliged to supply heat. Under Danish law the TSO is not allowed to curtail wind generation. This in effect causes subsidised energy to be exported to neighbouring countries. According to the OECD (2009) the probable value of subsidies that were exported between the years of 2000 and 2008 amount to €916 million.

2.4.7 Further expansion of wind power in Denmark

Denmark strives for an environmentally-friendly electrical energy production and consistently embarks on research, development and demonstration of new technologies in wind, solar and bio-mass. The country is striving for more than 50% of total system energy from wind power by 2020. In order to meet the target, a total of 4600 MW was identified in 23 sites of 200 MW, of which seven have been prioritised, although there is no binding obligation from the politicians.

Although the Danes were initially not bothered by the introduction of wind generators they have since proved to have some resistance against the addition of more wind generators. The Danes are generally pro wind turbines, but “not in my back yard”. People are starting to protest against having wind turbines in their areas purely based on aesthetics. Due to this the focus for expansion is now more on off-shore wind farms.

As indicated earlier, the Danish government’s long-term policy goal is to be independent from fossil fuels by the year 2050. The target that was set for wind power deployment for the period 2008-2012, required the installation of 1150 MW of new capacity. It was divided between 800 MW of new off-shore wind capacity and 350 MW of new on-shore wind capacity.

The short-term target of 800 MW off-shore wind capacity is bound to be achieved through the commissioning of three large off-shore wind farms; Horns Rev II (209 MW, commissioned in September 2009), Rødsand II (207 MW, commissioned in October 2010) and Anholt (400 MW still planned for December 2012).

The Danish contribution for the European Union 2020 policy goals is a target of 30% renewable energy consumption including the transport sector. Currently gross consumption of renewable energy is approximately 20%. The goal is that wind will supply 50% of domestic electrical energy demand. This will require the generation of approximately 11 TWh from 4 GW of installed wind power capacity.

Future expansion has been studied by Denmark’s Energinet.dk through the Ecogrid group. The study concluded that drastic re-engineering of the whole system will be needed if trends continue with regards to the capacity expansion of wind generation. Figure 12 shows the power that will be needed for reserve management should the introduction of additional wind power remain uncurtailed. From the chart it is clear that a very flexible residual power reserve will be needed to achieve system balance.

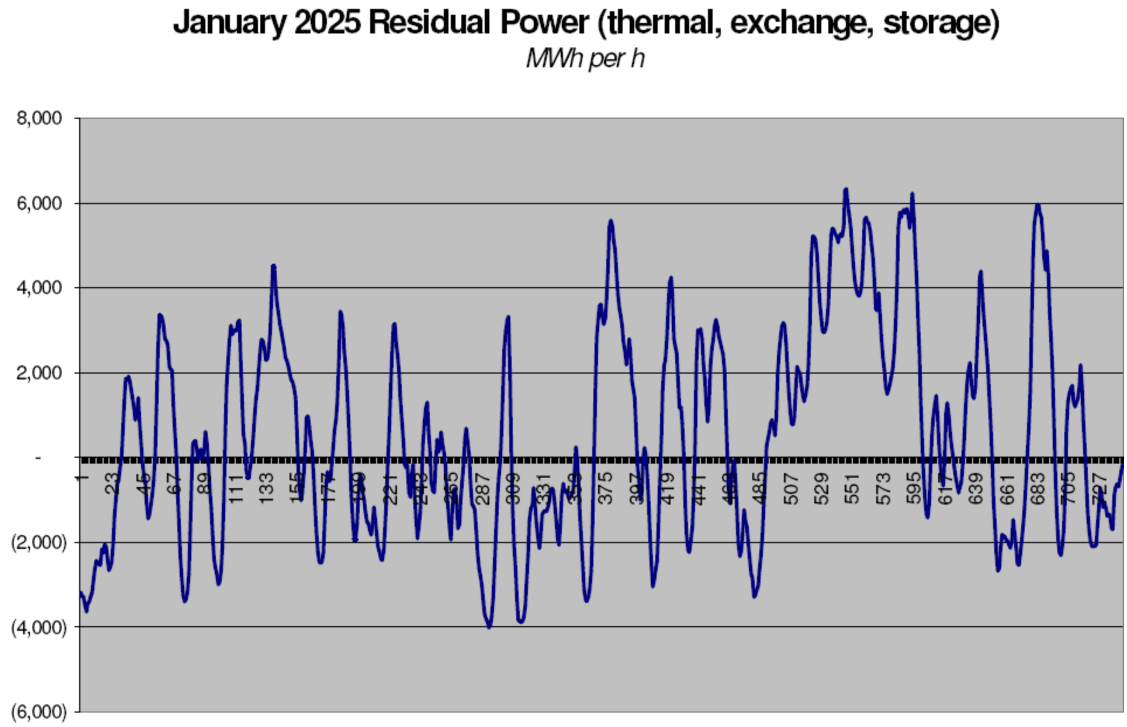

Figure 12: Probable residual power usage for January 2025 (Center for Politiske Studier, 2009)

2.5 Conclusion

Eskom's philosophy for the control of the frequency during normal and abnormal conditions was discussed in detail. Furthermore, Eskom's 2012 instantaneous reserve requirements were discussed in detail and this was contrasted with how Denmark has integrated wind generation into their electrical network.

Chapter 3

This chapter discusses the WASA project and the wind data to be used to convert wind speeds into corresponding power outputs according to the locations of the fifteen proposed wind farms from the bid submissions of round 1 and round 2 of the RE IPP programme.

Chapter 3 Empirical Investigation

3.1 Introduction

This chapter discusses the Wind Atlas of South Africa project and the wind data that will be used to convert wind speeds into associated electrical power outputs according to the locations of the fifteen wind farms and their capacities as were allocated by the DoE in round 1 and round 2 of the RE IPP programme. Historical Eskom generator output data to be used, sourced from Eskom's Phoenix database at National Control, will also be discussed.

3.2 Wind data

The gathering of historical wind data in South Africa has not been a priority previously and if data were collected it was basically at heights of levels close to ground. These wind measurements would essentially not be of any worth for wind power planning purposes due to the fact that most wind turbines are located on top of masts with lengths in excess of 60 meters. In order to address this shortcoming in available data the Wind Atlas of South Africa (WASA) project was initiated and ten wind measurement stations have been installed covering the areas of the Northern, Western and Eastern Cape Provinces. These stations are now taking measurements at heights of up to 62 meters above ground level. These measurements are for verification purposes of the Wind Atlas that is presently in the process of development and is available online in the public domain in the form of 10-minute integrated data. The data can be downloaded free of charge at http://wasadata.csir.co.za/wasa1/WASAData.

For the purpose of this investigation wind data from the ten wind measurement stations of the WASA project will be used. Each of the 15 proposed wind farms who successfully bid in round 1 and round 2 of the RE IPP programme as well as Eskom's future Sere wind farm will be coupled with measured wind data from its nearest WASA wind measurement station. An associated electrical power output for each wind farm will be derived from its wind data. The total of the electrical power outputs from the 16 wind farms will then be superimposed on the actual historical Eskom generation in order to determine what the effect would be had wind generation been part of the generation mix.

3.2.1 About WASA

Phase 1 of the South African Wind Energy Programme (SAWEP) was implemented between February 2008 and December 2010 (South African Wind Energy Programme, 2012). From one of the outcomes of phase 1, a need developed to establish the means required to enable authorities, investors, power sector and industry to investigate the viability of wind generation in South Africa. A methodology for mapping the wind resources on a national and regional level, as well as tools for estimating the annual energy production (AEP) of proposed wind farms throughout South Africa were required. In order to meet these objectives the WASA project was launched.

The WASA project with the main aim to develop a Numerical Wind Atlas (NWA) for South Africa commenced on 30 June 2009. In the WASA modelling domain, wind climate data will be available every 5 km x 5 km corresponding to approximately 15 000 virtual masts. The project was implemented as a twinning arrangement between South African partners and the Royal Danish Embassy (RDE). It has the South African National Energy Research Institute (SANERI) as coordinator with other South African partners consisting of (About Wind Atlas for South Africa, 2012):

- Climate System Analysis Group, University of Cape Town (UCT CSAG),
- Council for Scientific and Industrial Research (CSIR), and
- South African Weather Service (SAWS).

3.2.2 WASA measurement stations

Ten literal wind measurement stations covering areas of the Northern, Western and Eastern Cape Provinces started collecting data at height levels of up to 62 meters above ground level. Site information of the ten genuine masts is given in Table 13 with a map of their geographical locations as indicated in Figure 13.

Table 13: WASA mast information

Site	Latitude (Decimal Degrees)	Longitude (Decimal Degrees)	Closest Town	Data Start date
WM01	-28.601882	16.664410	Alexander Bay	2010/06/23
WM02	-31.524939	19.360747	Calvinia	2010/06/30
WM03	-31.730507	18.419916	Vredendal	2010/06/24
WM04	-32.846328	18.109217	Vredenburg	2010/05/18
WM05	-34.611915	19.692446	Napier	2010/05/20
WM06	-32.556798	20.691243	Sutherland	2010/09/17
WM07	-32.966723	22.556670	Beaufort West	2010/05/28
WM08	-34.109965	24.514360	Humansdorp	2010/08/04
WM09	-31.252540	25.028380	Noupoort	2010/09/01
WM10	-32.090650	28.135950	Butterworth	2010/08/05

The station situated at Vredenburg was the first station in commission and started to collect data from 18 May 2010. The station situated in Sutherland was the last of the stations to be commissioned and started to collect data from 17 September 2010. It is anticipated that the ten measurement stations will collect data for a period of four years. These measurements will help to verify and improve the models used that will ultimately result in a NWA for South Africa (About Wind Atlas for South Africa, 2012).

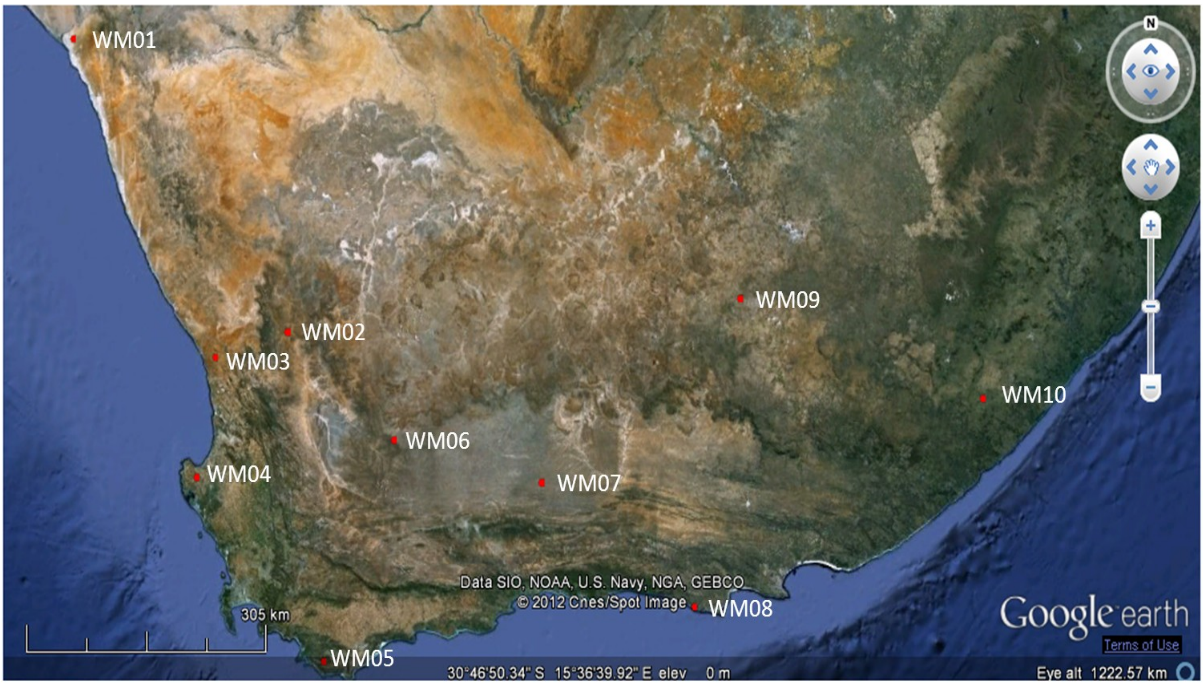

Figure 13: Locations for the 10 wind measurement stations of the WASA project

3.2.3 Instruments used in the WASA project

Instruments are mounted on masts at different height levels and the data is sampled at 2 second intervals. Every 10 minutes, the average, minimum, maximum and standard deviation statistics of the measurements are calculated and recorded together with time information (CSIR, 2010).

The mast arrangement used at the wind measurement sites can be seen in Figure 14.

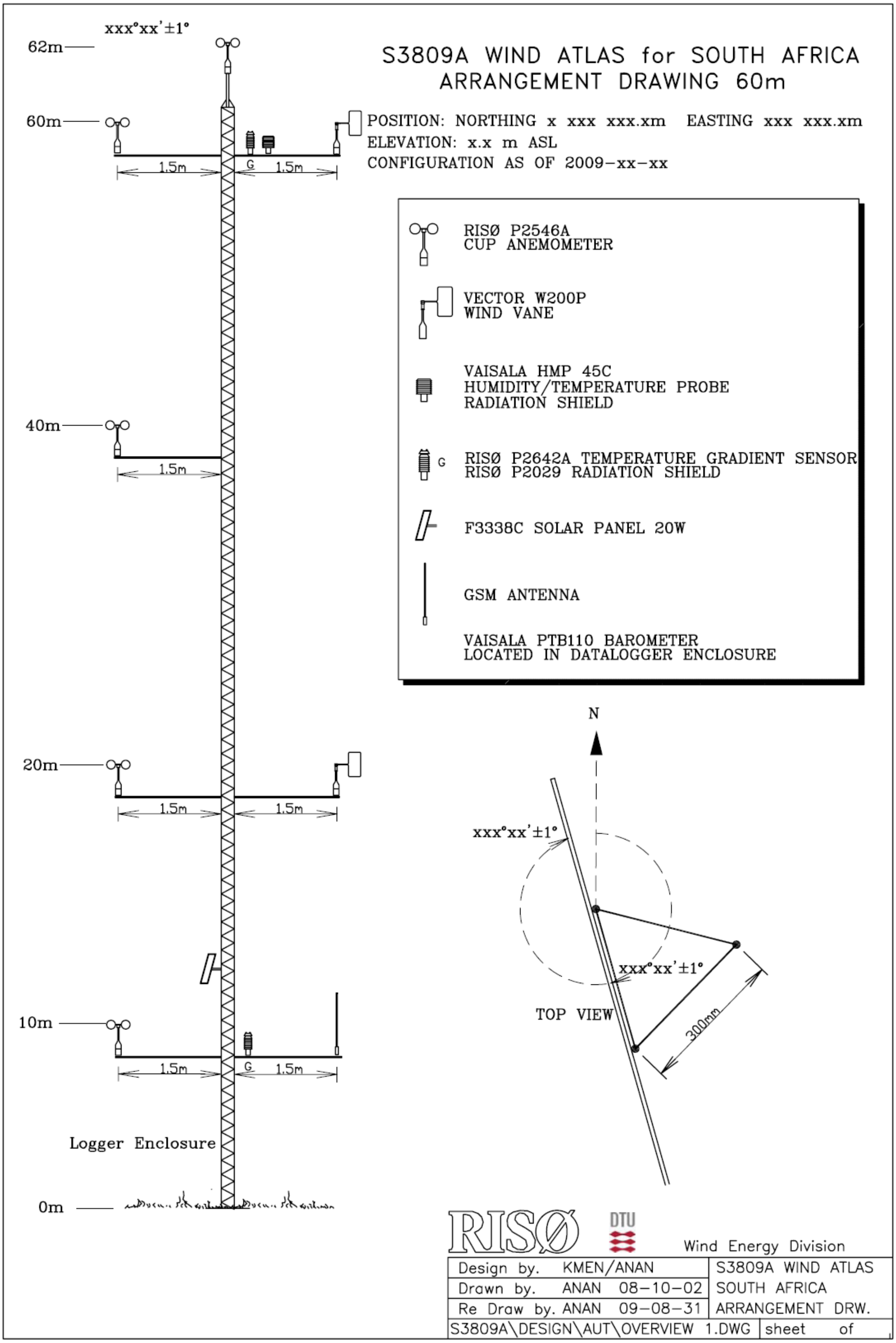

Figure 14: Mast arrangements of the wind measurement sites (CSIR, 2010)

The instruments used in the project are as follows (CSIR, 2010):

Cup Anemometers

Model: P2546A

Manufacturer: WindSensor, Denmark

Heights: 10 m, 20 m, 40 m, 60 m, 62 m

Calibrated by: Svend Ole Hansen ApS, Denmark

Potentiometer wind vanes

Model: W200P

Manufacturer: Vector Instruments, United Kingdom

Heights: 20 m, 60 m

Temperature and Relative Humidity Probes

Model: HMP45C

Manufacturer: Campbell Scientific Ltd, United Kingdom

Height: 60 m

Calibrated by: Vaisala Oyj, Finland

Temperature difference sensors

Model: P2642A Pt 500

Manufacturer: Risø, Denmark

Heights: 60 m, 10 m

Calibrated by: Risø, Denmark

Barometers

Model: PTB110

Manufacturer: Vaisala, Finland

Height: 6 m

Calibrated by: Vaisala Oyj, Finland

Data loggers/ CompactFlash Module

Model: CR1000 / CFM100

Manufacturer: Campbell Scientific, Inc, United Kingdom

Height: 6 m

Calibrated by: Campbell Scientific Ltd, United Kingdom

3.3 Wind farm information

Round 1 and round 2 of the RE IPP programme resulted in 15 successful bids representing 15 wind farms with a total capacity of 1196 MW.

Information with regards to the locations of the wind farms, the capacity allocated to them, the number of wind turbine generators at each farm and the WASA mast that will be used for the wind speed measurements is given in Table 14. Also included in the table is information on Eskom's Sere wind farm that is due for completion in December 2013.

Table 14: Wind farm information

Site	Latitude (Decimal Degrees)	Longitude (Decimal Degrees)	Nearest WASA mast	Distance to nearest WASA mast (km)	Capacity (MW)	Number of turbines	Total area swept (m^2)
WF01	33.26774	19.04122	WM04	98.8	135.2	45	286 290
WF02	31.70431	23.17592	WM07	152.0	72.7	24	152 688
WF03	31.47876	26.44539	WM09	137.0	97.0	32	203 584
WF04	34.22679	19.38084	WM05	51.4	26.2	8	50 896
WF05	33.96222	25.24444	WM08	69.4	26.2	8	50 896
WF06	34.14656	24.71723	WM08	19.1	77.6	25	159 050
WF07	34.00030	24.83860	WM08	32.3	133.9	44	279 928
WF08	33.09583	18.40056	WM04	38.8	65.4	21	133 602
WF09	32.81176	25.90558	WM09	192.0	135.0	45	286 290
WF10	32.74625	25.93167	WM09	186.0	137.9	45	286 290
WF11	34.08445	24.49889	WM08	3.2	94.8	31	197 222
WF12	32.83480	18.00153	WM04	10.2	90.8	30	190 860
WF13	33.33387	26.46914	WM08	201.0	23.4	7	44 534
WF14	33.68475	25.60471	WM08	111.0	59.8	19	120 878
WF15	32.58947	27.34198	WM10	93.0	20.6	6	38 172
Sere	31.52703	18.12447	WM03	36.0	100.0	33	209 946

A map with the geographical locations of the 15 wind farms from round 1 and round 2 as well as Eskom's Sere wind farm is shown in Figure 15. The mast positions from the WASA project are indicated in red with the locations of the wind farms indicated in green.

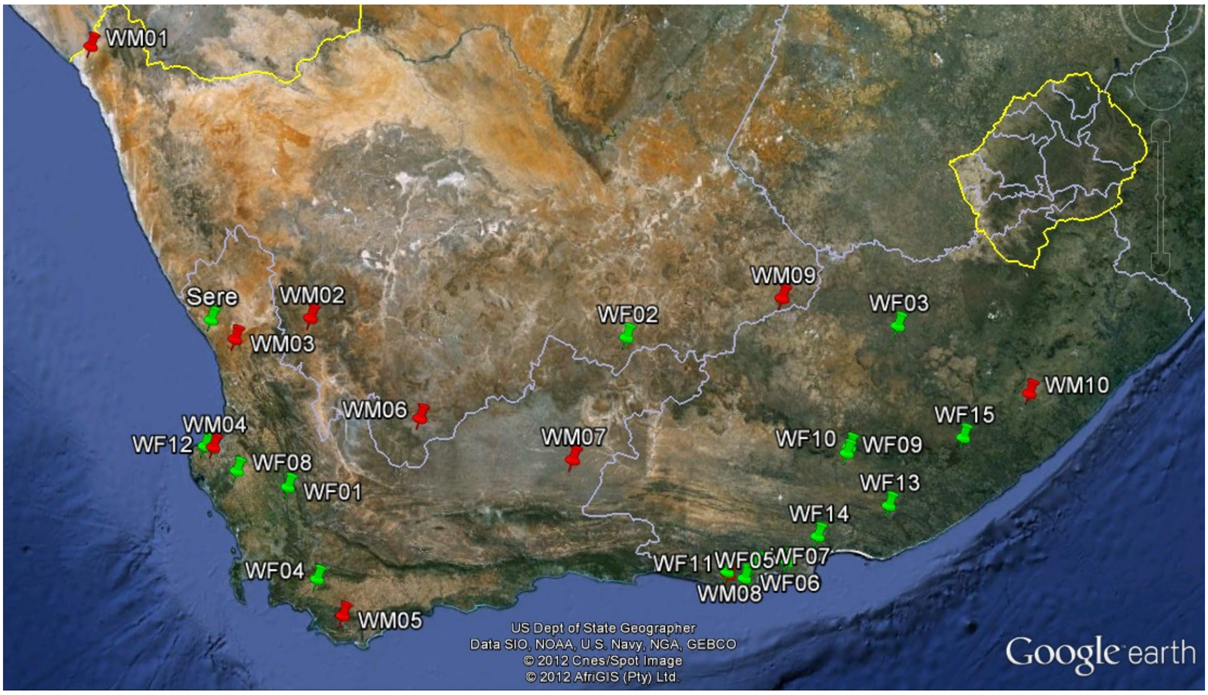

Figure 15: Locations of the 15 proposed wind farms from rounds 1 and 2 of the RE IPP programme

3.3.1 *Wind turbine characteristics*

Typical wind turbine generator characteristics will be used. For the purpose of the study it is assumed that all wind farms consist of multiple 3 MW units, each with the following characteristics:

- Nominal revolutions: 16 rpm
- Tower mast height: 62 m
- Rotor diameter: 90 m
- Area swept: 6362 m^2
- Air density: 1.225 kg/m^3
- Power coefficient: 40%
- Generator efficiency: 100%
- Gearbox efficiency: 100%

3.4 Historical Eskom generation output data

Historical load data for the Eskom network was obtained from actual historical Eskom generation output data. This data was sourced from Eskom's Phoenix database at National Control. Data with regards to the use of Eskom's emergency resources will be obtained from Eskom's Transmission Morning Report. The Transmission Morning Report is a report that is published at 06:00 daily by National Control and is available on Eskom's intranet. This report contains, amongst other, information about all incidents that happened the day before on Eskom's transmission network.

3.5 Period of concern

The historical periods that are of interest for the purpose of this study, are the months of December 2011 and July 2012. These two months are of interest, because they represent the most recent summer minimum and winter maximum load conditions experienced on the Eskom network as well as having the most complete set of associated wind data available.

The summer minimum load conditions are used by Eskom to do maintenance on its generating units in order to have as much generating capacity available for the winter peak loading conditions. In recent years, this has meant that Eskom operated with a very small reserve margin during the summer months.

During winter maximum loading conditions, the maximum available percentage of Eskom's generation resources are utilised to meet the demand. Due to a general shortage of generation experienced on the Eskom network in recent years, all of Eskom's generation resources are often not enough to meet the projected demand and reserve requirements. When Eskom is not able to meet the demand with the resources available it is regarded as being an abnormal condition. During such times Eskom will control the frequency as discussed in paragraph 2.2.7.

3.6 Data quality

3.6.1 Wind data allocations

From Table 14 it is noted that only seven out of the ten wind measurement stations from the WASA project will be used to source data to the wind farms, effectively reducing the variability in the number of wind farms from sixteen to seven. Wind measurement stations 1, 2 and 6 will not be used, simply because the wind farms nearest to these three stations have measurement stations that are closer to them.

Between wind masts 4, 8 and 9 a total of 1077 MW worth of wind farms are represented making up 83% of the total capacity.

Wind mast 4 represents three wind farms totalling 291.4 MW to make up 22.5% of the total capacity of the wind farms. The average distance of these three wind farms to wind mast 4 is 49.3 km. Two of the three wind farms are relatively close to the wind mast with distances of 10.2 km and 38.8 km respectively. The farthermost wind farm is 98.8 km away from wind mast 4.

Wind mast 8 represents six wind farms totalling 416 MW to make up 32.1% of the total capacity of the wind farms. The average distance of these six wind farms to wind mast 8 is 72.7 km. Four of the wind farms are situated between 3.2 km and 69.4 km from the wind mast. The two farthermost wind farms are 111 km and 201 km away from the wind mast.

Wind mast 9 represents three wind farms totalling 370 MW to make up 28.5% of the total capacity of the wind farms. The average distance of these three wind farms to wind mast 9 is 171.7 km.

3.6.2 Completeness of data

For the December 2011 data, recorded data for wind mast 9 is only available from 12:40 PM of day 22 onwards. The rest of December's data is complete for all remaining wind measuring stations.

For the July 2012 data, between 11:20 AM of day 13 and 03:00 PM of day 15, no data recorded is available for wind mast 9. For wind mast 10, recorded data is only available onwards from 01:10 PM of day 11. The rest of July's data is complete for all remaining wind measuring stations.

The actual historical Eskom generation data is complete for both December 2011 and July 2012. The information with regards to the utilisation of Eskom's emergency resources is also complete.

3.7 Conclusion

Measured data at the wind measuring stations from the WASA project is true, accurate and mostly complete for the time of concern at height levels of up to 62 meters above ground level.

The fact that data from only seven out of ten wind measurement stations of the WASA project will be used effectively reduces the statistical variability of the number of wind farms from sixteen to seven. However, the total capacity from all the wind farms combined remains the same.

Actual wind speed data from the wind measurement stations of the WASA project can be seen to represent true and realistic measured wind speed data for the total capacity of all the wind farms combined.

Chapter 4

This chapter gives the results and findings from the data collected in the empirical investigation discussed in Chapter 3.

Chapter 4 Results and Findings

4.1 Introduction

This chapter discusses the historical Eskom data for the months of December 2011 and July 2012. Actual historical Eskom generation data, historical utilisation of emergency resources and low frequency events that occurred on the network are analysed. In this chapter the wind speed data, as discussed in chapter 3, gets converted into electrical power output data.

4.2 Historical Eskom data

4.2.1 Total demand during December 2011

The maximum integrated hourly load demand on the Eskom network for December 2011 was for the hour ending 19:00 on the 5th and amounted to 32 349 MW. This demand was met through the use of 27 074 MW of electrical energy from coal, 1813 MW of electrical energy from nuclear, 1111 MW of electrical energy from pumped storage, 384 MW of electrical energy from hydro, 1504 MW of electrical energy from imported hydro and 461 MW of electrical energy from independent power producers. The minimum integrated hourly load demand was for the hour ending 03:00 on the 26th and amounted to 19 557 MW.

A load profile for December 2011 is shown in Figure 16.

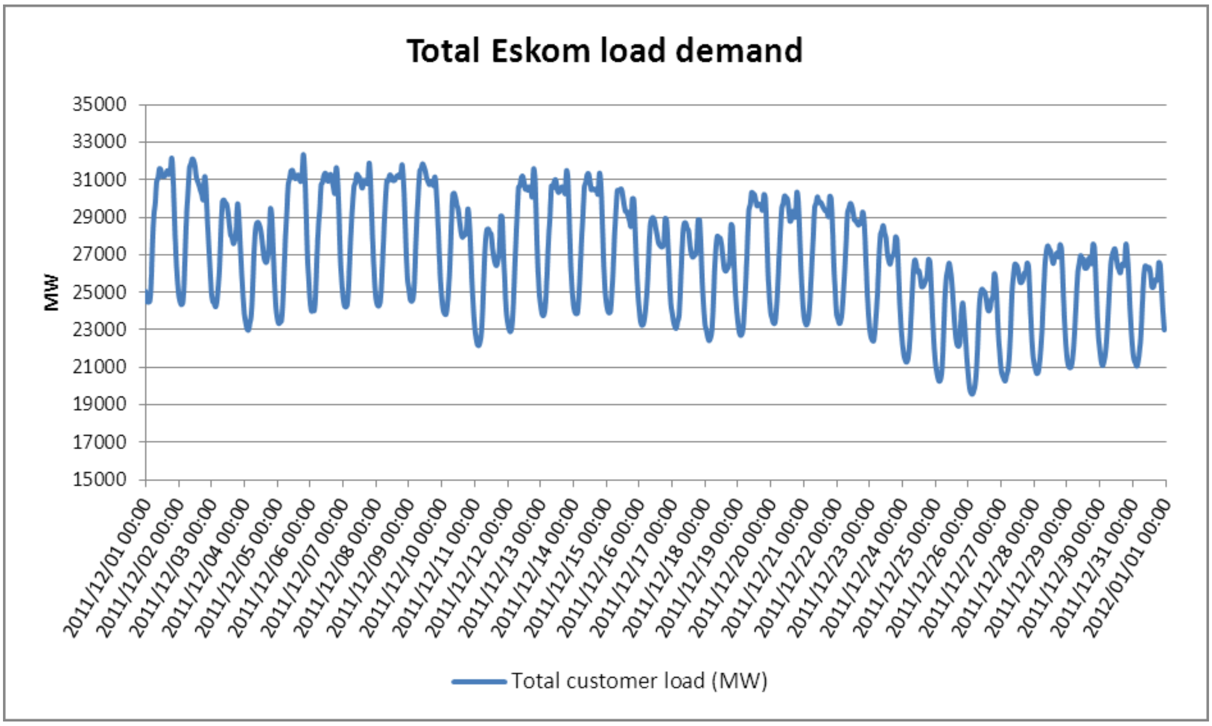

Figure 16: Eskom's load profile for December 2011

4.2.2 Utilisation of emergency resources during December 2011

4.2.2.1 Emergency Level 1 (EL1) usage

There were twenty incidents during the month of December 2011 where Eskom's generators were forced to go to EL1. On average, the generators contributed a combined 119 MW of additional power during these EL1 events. The duration for which the generators were in EL1 added up to 127.07 hours in total. The total EL1 generated power during December 2011 was 15 805 MWh.

Information on the EL1 events for December 2011 is given in Table 15.

Table 15: EL1 utilisation for December 2011

Date	Start time	End time	Duration (hh:mm)	Duration (Hrs)	Power (MW)	Energy (MWh)
2011/12/05	19:03	20:25	1:22	1.37	168.0	230
2011/12/06	17:48	20:00	2:12	2.20	11.5	25
2011/12/07	12:30	20:50	8:20	8.33	83.5	696
2011/12/08	08:48	20:55	12:07	12.12	18.0	218
2011/12/09	07:00	21:02	14:02	14.03	121.5	1705
2011/12/10	17:27	20:18	2:51	2.85	71.0	202
2011/12/11	10:45	14:37	3:52	3.87	90.0	348
2011/12/11	16:46	21:00	4:14	4.23	16.0	68
2011/12/12	10:25	13:18	2:53	2.88	124.5	359
2011/12/12	15:35	20:45	5:10	5.17	136.5	705
2011/12/13	16:30	20:55	4:25	4.42	120.5	532
2011/12/14	17:24	20:22	2:58	2.97	88.0	261
2011/12/15	07:40	21:33	13:53	13.88	221.5	3075
2011/12/19	09:01	21:13	12:12	12.20	184.0	2239
2011/12/20	08:19	20:54	12:35	12.58	107.0	1340
2011/12/21	10:15	20:49	10:34	10.57	148.0	1564
2011/12/27	18:42	20:52	2:10	2.17	158.0	343
2011/12/28	16:06	21:08	5:02	5.03	164.0	828
2011/12/29	16:38	21:13	4:35	4.58	171.0	782
2011/12/30	19:03	20:40	1:37	1.62	177.0	285

4.2.2.2 Interruptible load usage

There were six events during December 2011 where the use of interruptible loads was required. The total duration of interruptible load usage during December 2011 was four hours eleven minutes and resulted in 911 MWh of electricity sales that were not made.

Information with regards to interruptible load utilisation during December 2011 can be seen in Table 16 below.

Table 16: Interruptible load usage for December 2011

Date	Site	Start time	End time	Duration (Hrs)	Power requested (MW)	Average power (MW)	Energy (MWh)
2011/12/10	Bayside	17:37	18:39	1.03	150	131	135.4
2011/12/12	Hillside	15:39	15:54	0.25	437	439	109.7
2011/12/19	Bayside	09:02	09:22	0.33	150	130	43.3
2011/12/20	Bayside	14:31	14:52	0.35	150	131	45.8
	Mozal	14:35	14:58	0.38	450	446	171.0
2011/12/21	Bayside	11:26	12:06	0.67	150	131	87.3
	Hillside	11:30	11:58	0.47	437	485	226.3
2011/12/27	Bayside	19:08	19:50	0.70	150	131	91.7

4.2.3 Low Frequency Incidents during December 2011

According to Eskom's standard SOPST0004 *"Measurement and recording of Eskom frequency"*, a Low Frequency Incident (LFI) is regarded as an incident where the system frequency drops below 49.5 Hz (Ntusi, 2011).

There was one LFI during December 2011 where the frequency dropped to as low as 49.19 Hz. There were however an additional nineteen events where the frequency dropped to below 49.75 Hz.

Details of the low frequency events can be seen in Table 17.

Table 17: Low frequency events for December 2011

Date	Start time	Duration (Seconds)	Lowest frequency (Hz)	Reason for low frequency
2011/12/03	00:03:44	8	49.624	Majuba, Unit 1 tripped from 600 MW
2011/12/03	00:05:21	10	49.692	Frequency was gradually falling
2011/12/10	11:08:21	7	49.682	Apollo CS, Loss of 410 MW output
2011/12/10	16:39:26	3	49.697	Frequency was gradually falling
2011/12/10	17:25:58	28	49.699	Majuba, Unit 4 tripped from 650 MW
2011/12/10	17:37:02	95	49.696	Apollo CS, Loss of 1500 MW output
2011/12/12	15:15:43	57	49.624	Lethabo, Unit 6 tripped from 593 MW
2011/12/12	15:38:35	29	49.515	Majuba, Unit 4 tripped from 300 MW
2011/12/13	19:10:17	3	49.693	Apollo CS, Loss of 344 MW output
2011/12/19	09:01:31	2	49.698	Lethabo, Unit 4 tripped from 593 MW
2011/12/20	13:44:13	108	49.553	Apollo CS, Loss of 640 MW output
2011/12/20	14:30:44	153	49.503	Apollo CS, Loss of 860 MW output
2011/12/21	11:25:38	9	49.685	Majuba, Unit 6 tripped from 696 MW
2011/12/23	11:07:45	5	49.699	Kendal, Unit 3 tripped from 630 MW
2011/12/24	00:48:38	2	49.693	Apollo CS, Loss of 800 MW output
2011/12/27	05:58:12	2	49.692	Majuba, Unit 1 tripped from 500 MW
2011/12/27	18:41:40	98	49.188	Apollo CS, Loss of 1526 MW output
2011/12/28	18:37:01	2	49.695	Frequency was gradually falling
2011/12/28	19:05:34	44	49.538	Apollo CS, Loss of 665 MW output
2011/12/31	23:23:27	60	49.535	Majuba, Unit 4 tripped from 623 MW

4.2.4 Total demand during July 2012

The maximum integrated hourly load demand on the Eskom network for July 2012 was for the hour ending 18:00 on the 16th and amounted to 35 770 MW. This demand was met through the use of 28 783 MW of electrical energy from coal, 1818 MW of electrical energy from nuclear, 845 MW of electrical energy from pumped storage, 476 MW of electrical energy from hydro, 1444 MW of electrical energy from imported hydro, 336 MW of electrical energy from independent power producers and 2077 MW of electrical energy from gas. The minimum integrated hourly load demand was for the hour ending 03:00 on the 1st and amounted to 21 623 MW.

A load profile for July 2012 is shown in Figure 17.

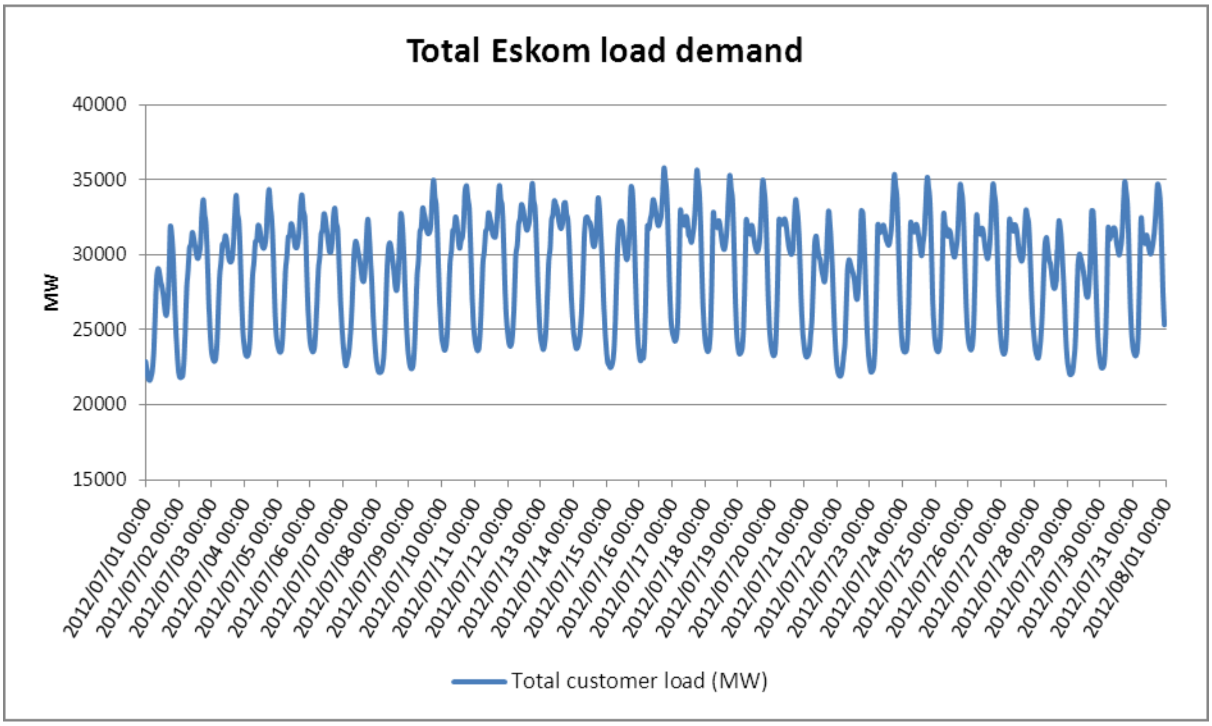

Figure 17: Eskom's load profile for July 2012

4.2.5 Utilisation of emergency resources during July 2012

4.2.5.1 EL1 usage

There were twenty two incidents during the month of July 2012 where Eskom's generators were forced to go to EL1. On average, the generators contributed an additional 122 MW combined during these EL1 events. The duration for which the generators were in EL1 added up to 85.94 hours in total. The total EL1 generated power during July 2012 was 11 088 MWh.

Information with regards to EL1 utilisation for July 2012 is given in Table 18.

Table 18: EL1 utilisation for July 2012

Date	Start time	End time	Duration (hh:mm)	Duration (Hrs)	Power (MW)	Energy (MWh)
2012/07/03	17:36	19:10	01:34	1.57	144.0	226
2012/07/05	17:11	19:41	02:30	2.50	148.5	371
2012/07/09	16:15	19:52	03:37	3.62	105.5	382
2012/07/10	16:56	19:29	02:33	2.55	112.5	287
2012/07/11	17:06	21:14	04:08	4.13	166.0	686
2012/07/12	09:00	20:46	11:46	11.77	167.0	1965
2012/07/13	10:26	12:55	02:29	2.48	174.5	433
2012/07/13	16:52	20:16	03:24	3.40	144.0	490
2012/07/14	17:40	19:29	01:49	1.82	168.0	305
2012/07/15	17:45	20:28	02:43	2.72	228.0	619
2012/07/16	06:27	21:22	14:55	14.92	183.5	2737
2012/07/17	16:00	21:11	05:11	5.18	54.5	282
2012/07/18	16:00	20:25	04:25	4.42	60.5	267
2012/07/19	16:00	21:04	05:04	5.07	22.0	111
2012/07/22	18:04	19:38	01:34	1.57	130.5	204
2012/07/23	17:35	19:48	02:13	2.22	139.5	309
2012/07/24	17:20	20:55	03:35	3.58	31.5	113
2012/07/25	17:48	20:21	02:33	2.55	75.0	191
2012/07/26	06:33	07:03	00:30	0.50	93.0	47
2012/07/26	17:28	19:40	02:12	2.20	124.5	274
2012/07/30	17:30	20:45	03:15	3.25	80.0	260
2012/07/31	16:50	20:45	03:55	3.92	135.0	529

4.2.5.2 Interruptible load usage

There were three events during July 2012 where the use of interruptible loads was required. Two of those events required that more than one pot line had to be shed. The total duration of interruptible load usage during July 2012 was three hours twenty three minutes and resulted in 954.12 MWh of electricity sales that were not made.

Information with regards to the interruptible load usage for July 2012 is given in Table 19 below.

Table 19: Interruptible load usage for July 2012

Date	Site	Start time	End time	Duration (Hrs)	Power requested (MW)	Average Power (MW)	Energy (MWh)
2012/07/05	Bayside	17:46	17:59	0.22	150	131	28.4
2012/07/11	Bayside	17:38	18:40	1.03	150	130	134.3
	Mozal	17:40	18:03	0.38	458	430	164.8
	Mozal	17:40	18:24	0.73	458	430	315.3
2012/07/13	Bayside	10:28	10:55	0.45	150	130	58.5
	Mozal	10:29	11:03	0.57	458	446	252.7

4.2.6 Low frequency incidents during July 2012

There were two LFIs during July 2012 where the frequency dropped to as low as 49.29 Hz and 49.33 Hz respectively. There were also an additional eighteen events where the frequency dropped to below 49.75 Hz.

Details with regards to the low frequency events can be seen in Table 20.

Table 20: Low frequency events for July 2012

Date	Start time	Duration (Seconds)	Lowest frequency (Hz)	Reason for low frequency
2012/07/05	17:44:06	4	49.697	Frequency was gradually falling
2012/07/05	17:44:38	46	49.656	Frequency was gradually falling
2012/07/07	03:08:31	3	49.679	Kendal, Unit 4 tripped from 392 MW.
2012/07/09	20:02:26	1	49.696	Frequency was gradually falling
2012/07/11	17:36:08	116	49.294	Koeberg, Unit 1 tripped from 920 MW
2012/07/12	04:05:00	5	49.677	Kendal, Unit 1 tripped from 496 MW
2012/07/13	10:15:25	1	49.698	Frequency was gradually falling
2012/07/13	10:17:11	6	49.696	Frequency was gradually falling
2012/07/13	10:21:52	482	49.332	Apollo CS, Loss of 198 MW output & Matla, Unit 6 tripped
2012/07/13	11:20:27	13	49.689	Frequency was gradually falling
2012/07/13	17:45:17	3	49.696	Frequency was gradually falling
2012/07/13	22:49:58	1	49.695	Frequency was gradually falling
2012/07/16	08:09:04	104	49.654	Matla, Unit 3 tripped from 575 MW
2012/07/17	09:23:14	7	49.643	Apollo DC, Loss of 820 MW output
2012/07/19	05:47:46	5	49.665	Majuba, Unit 6 tripped from 590 MW.
2012/07/19	08:13:32	5	49.676	Matla, Unit 3 tripped from 540 MW
2012/07/19	10:15:48	166	49.501	Apollo CS, Loss of 820 MW output
2012/07/24	06:24:12	1	49.698	Apollo CS, Loss of 222 MW output
2012/07/27	10:14:34	1	49.697	Kendal, Unit 6 tripped from 640 MW
2012/07/27	23:42:37	2	49.689	Kendal, Unit 1 tripped from 456 MW

4.3 Wind data

4.3.1 Wind profile

A graph of the ten minute average wind speed values covering the duration of one day that was measured at wind mast 3 during December 2011 at a height of 62 meters above ground is given in Figure 18. This graph is representative of the typical daily profile for average wind speeds measured at all the wind measurement stations at heights of 62 meters above ground level for both December 2011 and July 2012.

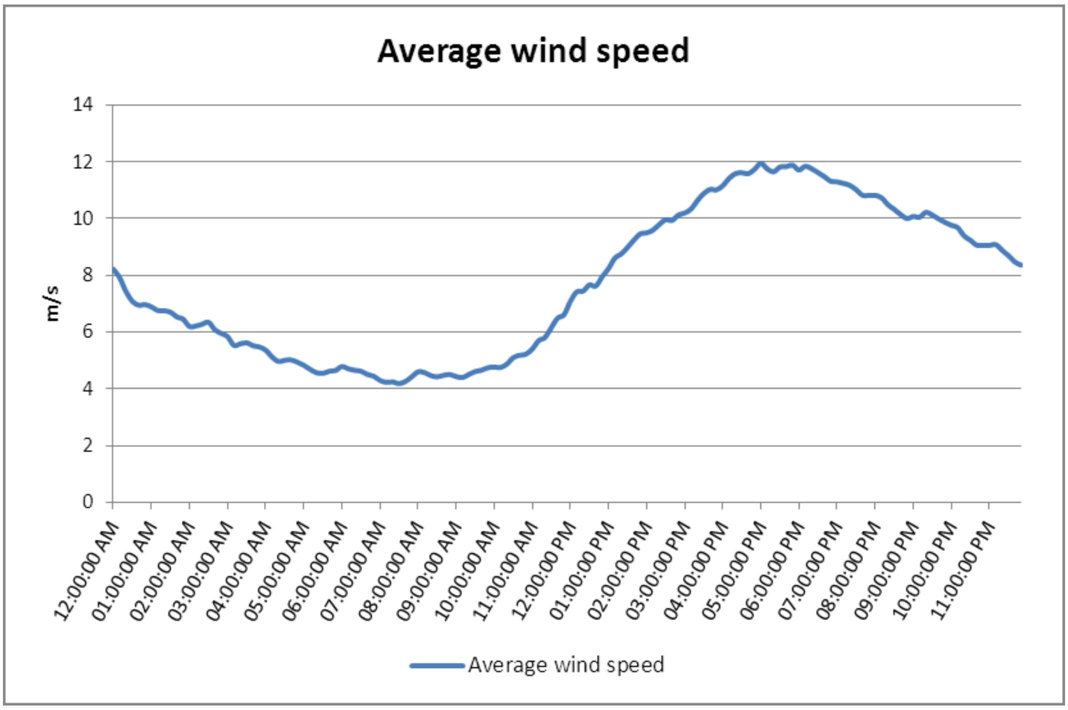

Figure 18: Average wind speeds for wind mast 3 during December 2011

From the graph it is noted that average wind speeds decrease between midnight and early mornings up until seven o'clock. Round about nine o'clock in the morning, average wind speeds start to pick up again to peak around six o'clock in the evening.

4.3.2 December 2011

During December 2011, the highest ten minute average wind speed was measured at wind mast 5 and was measured to be 8.48 m/s. The maximum wind speed was measured at wind mast 10 and was measured to be 24.48 m/s.

The minimum, maximum and average wind speeds that were measured at the seven wind measuring stations during December 2011 are given in Table 21.

Table 21: Wind speed data for December 2011

	WM03	WM04	WM05	WM07	WM08	WM09	WM10
Min (m/s)	0.47	0.31	0.33	0.37	0.23	0.00	0.27
Max (m/s)	20.21	19.28	20.36	19.52	18.69	19.10	24.48
Ave (m/s)	7.76	8.12	8.48	7.29	7.11	2.39	6.82

Daily minimum, maximum and average wind speeds that were measured at the seven wind measuring stations during the weeks of December 2011 are available in the Appendix.

4.3.3 July 2012

For July 2012, the highest ten minute average wind speed was measured at wind mast 9 and was measured to be 8.85 m/s. The maximum wind speed was measured at wind mast 8 and was measured to be 25.02 m/s.

The minimum, maximum and average wind speeds that were measured at the seven wind measuring stations during July 2012 are given in Table 22.

Table 22: Wind speed data for July 2012

	WM03	WM04	WM05	WM07	WM08	WM09	WM10
Min (m/s)	0.28	0.30	0.21	0.26	0.23	0.86	0.27
Max (m/s)	16.16	15.26	25.01	17.22	25.02	21.07	24.11
Ave (m/s)	6.59	5.68	8.03	6.72	7.92	8.85	7.73

Daily minimum, maximum and average wind speeds that were measured at the seven wind measuring stations during the weeks of July 2012 are available in the Appendix.

4.4 Wind power calculations

Wind turbines work on the principle of converting the kinetic energy within wind into electrical energy. The energy available for conversion is mainly dependent on the wind speed and the area swept from the turbine blades.

For the kinetic energy of the wind to be converted into electrical energy the following formula is used (Wind Turbine Power Generator Equation Formulas Design Calculator, 2002):

$$P = 1/2\rho v^3 c_p N_g N_b \qquad [W/m^2] \qquad (2)$$

Where,

P = power	[W/m^2]
ρ = air density	[kg/m^3]
v = wind speed	[m/s]
c_p = power coefficient	[%]
N_g = generator efficiency	[%]
N_b = gearbox efficiency	[%]

4.4.1 Air density

Wind turbine generator output is influenced by the density of air flowing across the rotor. Manufacturers typically provide a set of turbine power curves for various air densities. Energy estimates are therefore dependent on the predicted air density for the site. For simplicity, an air density of 1.225 kg/m^3 has been assumed at all the wind farms.

4.4.2 Power coefficient

Albert Betz concluded in the year 1919 that it is impossible for any wind turbine to convert more than 59.3% of the kinetic energy of wind into mechanical energy. Today this is known as the Betz limit and represents the maximum power coefficient of any wind turbine (Wind turbine design, 2012). Recently Robert Bass has proved that an efficiency of up to 97% can be achieved (Bass, 2007). However, for the purpose of this study, a power coefficient of 40% has been assumed.

4.4.3 Generator and gearbox efficiency

For simplicity and for the purpose of this dissertation, generator and gearbox efficiencies for all wind turbine generators have been chosen to be 100%.

4.4.4 Area swept

An assumption is made that all wind turbine units will have rotor diameters of 90 meters. The area swept for each individual wind turbine is thus the same and is calculated according to:

$$Area = \pi R^2 \qquad [m^2] \qquad (3)$$

Where,

R = radius [m]

With a rotor diameter of 90 meters, the area swept equals to 6362 m^2. The total area swept per wind farm is simply the number of wind turbine generators at that specific farm multiplied by the area swept per individual wind turbine.

4.4.5 Number of wind turbine generators per wind farm

The number of wind turbine generators at a specific wind farm is derived from the capacity that was allocated to that wind farm by the DoE. The number of wind turbine generators per farm is simply the total capacity of that specific farm divided by the capacity of a single wind turbine generator, which is assumed to be 3 MW. The number of wind turbine units per farm varies between 6 and 45.

4.5 Wind power output

4.5.1 Hourly integrated wind power output for December 2011

The would-be hourly integrated wind power output for the month of December 2011 for the aggregated wind farm outputs is shown in Figure 19. The wind farms would have produced a total of 246 972 MWh of electrical energy had they been online.

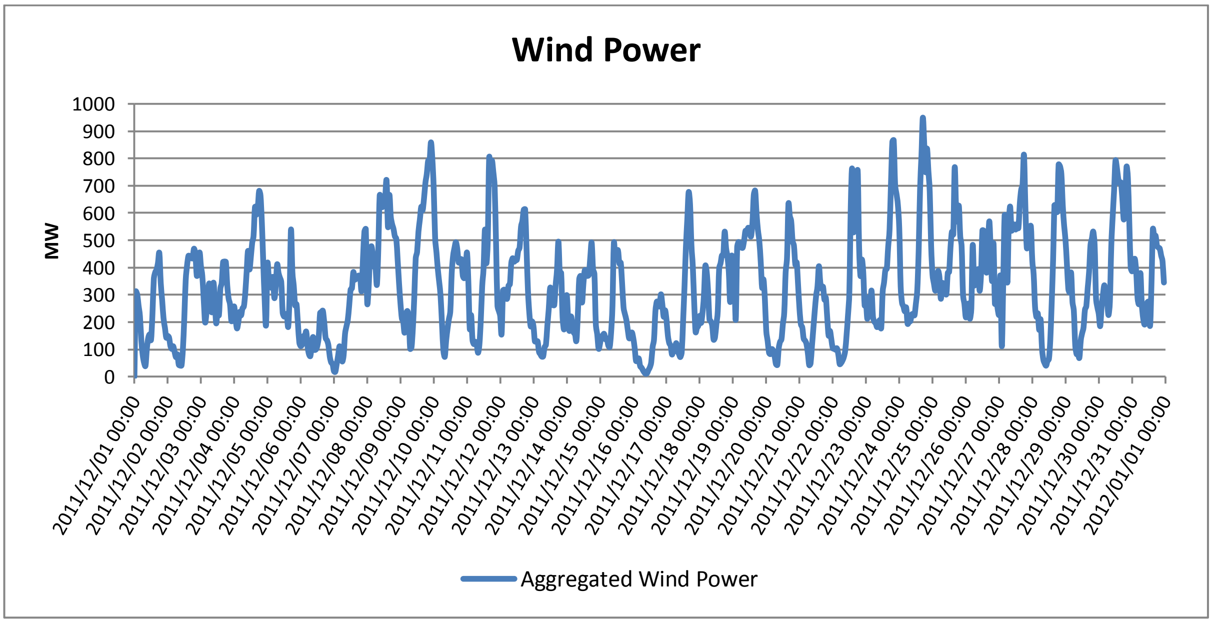

Figure 19: Wind power output for December 2011

4.5.2 Hourly integrated wind power output for July 2012

The would-be hourly integrated wind power output for the month of July 2012 for the aggregated wind farm outputs is shown in Figure 20. The wind farms would have produced a total of 298 193 MWh of electrical energy had they been online.

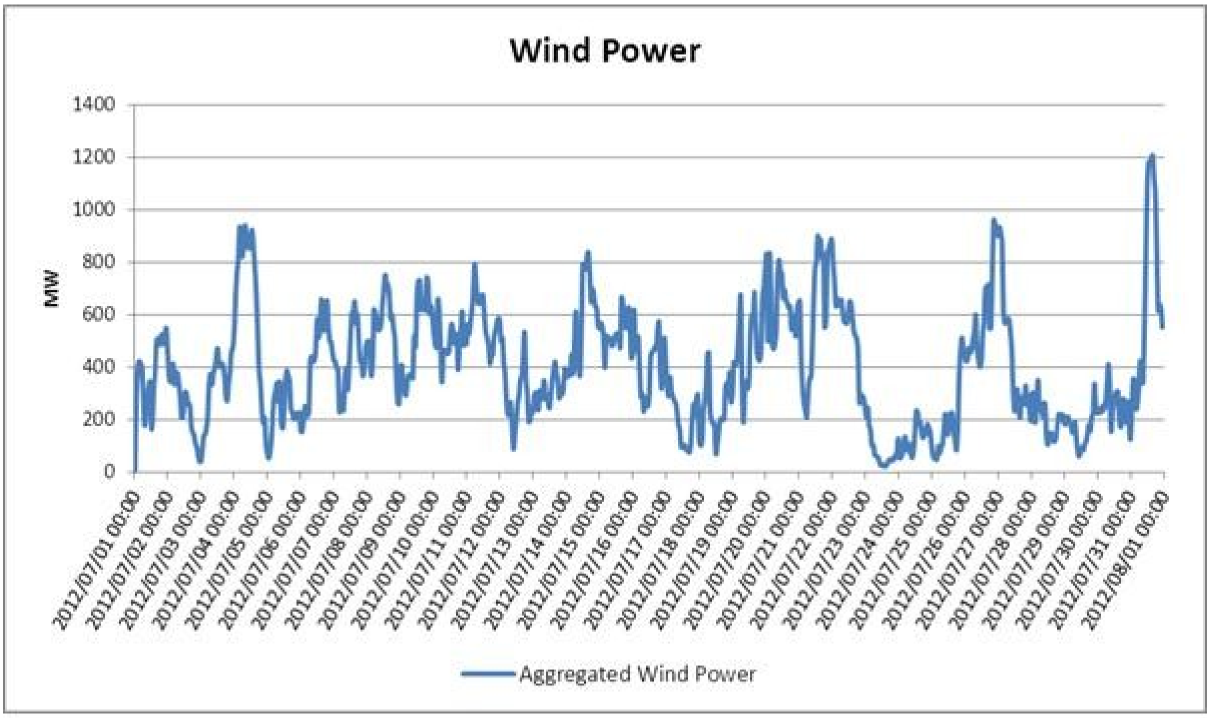

Figure 20: Wind power output for July 2012

4.6 Conclusion

In this chapter, the historical Eskom data for the months of December 2011 and July 2012 was discussed. Actual historical Eskom generation data, historical utilisation of emergency resources and low frequency events that occurred on the network were analysed. Wind speed data, as discussed in chapter 3, was converted into electrical power output data.

Chapter 5

This chapter interprets the information from the empirical investigation

Chapter 5 Discussion and interpretation

5.1 Introduction

This chapter interprets the actual historical Eskom data and the would-be generation from wind. It takes the wind generation as discussed in chapter 4, combines it with the actual Eskom generation data and studies the effect that wind generation would have had on Eskom's actual generation resources had wind been a part of the generation mix. It looks at how much of the emergency resources would have been replaced by wind energy and considers how much of the wind energy would have been unwanted for times when Eskom had surplus energy on the grid. It also studies the upward and downward ramp rates of the individual wind farms and compares it with the upward and downward ramp rates for all the wind farms combined.

5.2 Actual generation data

Due to technical and economic reasons Koeberg and Cahora Bassa normally run at full output and consequently do not contribute to spinning reserves. On the other hand and contrary to other countries, Eskom's thermal plants are allowed to ramp up and down in order to contribute up to 15% of their MCR towards spinning reserves (Smith *et al.*, 2012).

For both the months of December 2011 and July 2012, base load generation was made up out of nuclear electrical energy, imported hydro electrical energy from Cahora Bassa, electrical energy from independent power producers and majority of the electrical energy from coal. A small portion of the electrical energy from coal, hydro and pumped storage were used to meet the demand during peak conditions as is normally the case. During both these months there were times when gas turbines were required to be used as part of Eskom's emergency resources in order to meet the demand. Pumping load at Eskom's pumped storage schemes helped to smooth out the profile of the daily demand during off-peak periods.

5.2.1 December 2011

The total electrical energy generated during December 2011 was 20.3 TWh and was made up as per the information in Table 23.

Table 23: Plant utilisation over December 2011

Generation technology	Electrical energy generated (GWh)	Percentage contribution (%)
Nuclear	1272	6.37
Imported hydro	1088	5.45
IPP	329	1.65
Coal	17 208	86.21
Hydro	77	0.39
Pumped storage	252	1.26
Gas	59	0.30
Total	**20 284**	**100**

The total duration for which generators were in EL1 during December 2011 added up to 127.07 hours. Of the 17 208 GWh of electrical energy generated from coal, 0.1% totalling 15.8 GWh was EL1 generated electrical energy. The total amount of gas generated electrical energy added up to 59.5 GWh during December 2011. During the month of December, 910.6 MWh of electrical energy could not be met through Eskom's generating resources and Eskom had to make use of interruptible loads to balance the supply with the demand.

Historical ramp rates for Eskom's actual load during December 2011 were as high as 2178.8 MW per hour upwards and as high as 2483.1 MW per hour downwards during normal operating conditions. This translates to an upwards ramp rate of 363.13 MW per ten minutes and a downwards ramp rate of 413.8 MW per ten minutes.

5.2.2 July 2012

The total electrical energy generated during July 2012 was 21.9 TWh and was made up as per the information in Table 24.

The total duration for which generators were in EL1 during July 2012 added up to 85.92 hours and of the 19.1 TWh of electrical energy generated from coal, 0.07% totalling 12.7 GWh was EL1 generated electrical energy. The total amount of gas generated electrical energy added up to 55.7 GWh during July 2012. During the month of July, 775.0 MWh of electrical energy could not be met through Eskom's generating resources and Eskom had to make use of interruptible loads to balance the supply with the demand.

Historical ramp rates for Eskom's actual load during July 2012 were as high as 4337.5 MW per hour upwards and as high as 3713.1 MW per hour downwards during normal operating conditions. This translates to an upwards ramp rate of 722.9 MW per ten minutes and a downwards ramp rate of 413.8 MW per ten minutes.

Table 24: Plant utilisation over July 2012

Generation technology	Electrical energy generated (GWh)	Percentage contribution (%)
Nuclear	1290	5.99
Imported hydro	904	4.2
IPP	250	1.16
Coal	19 079	88.57
Hydro	59	0.28
Pumped storage	251	1.16
Gas	56	0.26
Total	**21 888**	**100**

5.2.3 Actual weekly generation mix during December 2011

During the first week of December 2011, the demand was met through the utilisation of normal Eskom generating resources. Only one nuclear unit at Koeberg was available up until 04:04 on the 4th after which the second Koeberg unit returned to service from stator leak repairs. The utilisation of the gas turbines during this week was not as part of emergency resources, but the generation was used to address network constraints and to manage the dam levels at Palmiet. The weekly profile for the first week of December 2011 can be seen in Figure 21.

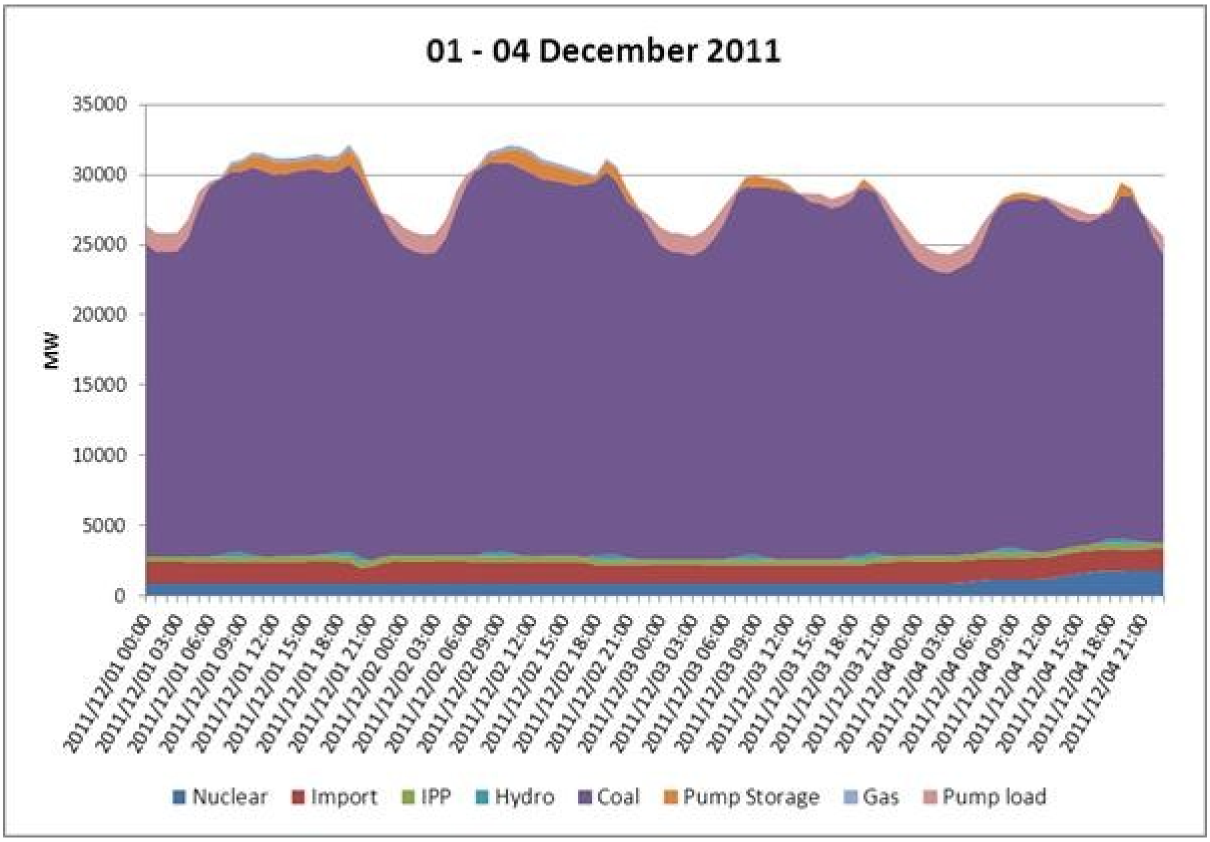

Figure 21: Generation mix during December 2011 - Week 1

During the second week of December 2011, EL1 was utilised on eight occasions due to a general shortage of supply. On one occasion 150 MW of interruptible load shedding (ILS) was needed to arrest the frequency decay when electrical energy import at Apollo Converter Station was suddenly reduced by 1500 MW due to the loss of all generation at Songo in Mozambique. During this week, gas turbines were used as part of the emergency resources. The weekly profile for the second week of December 2011 can be seen in Figure 22.

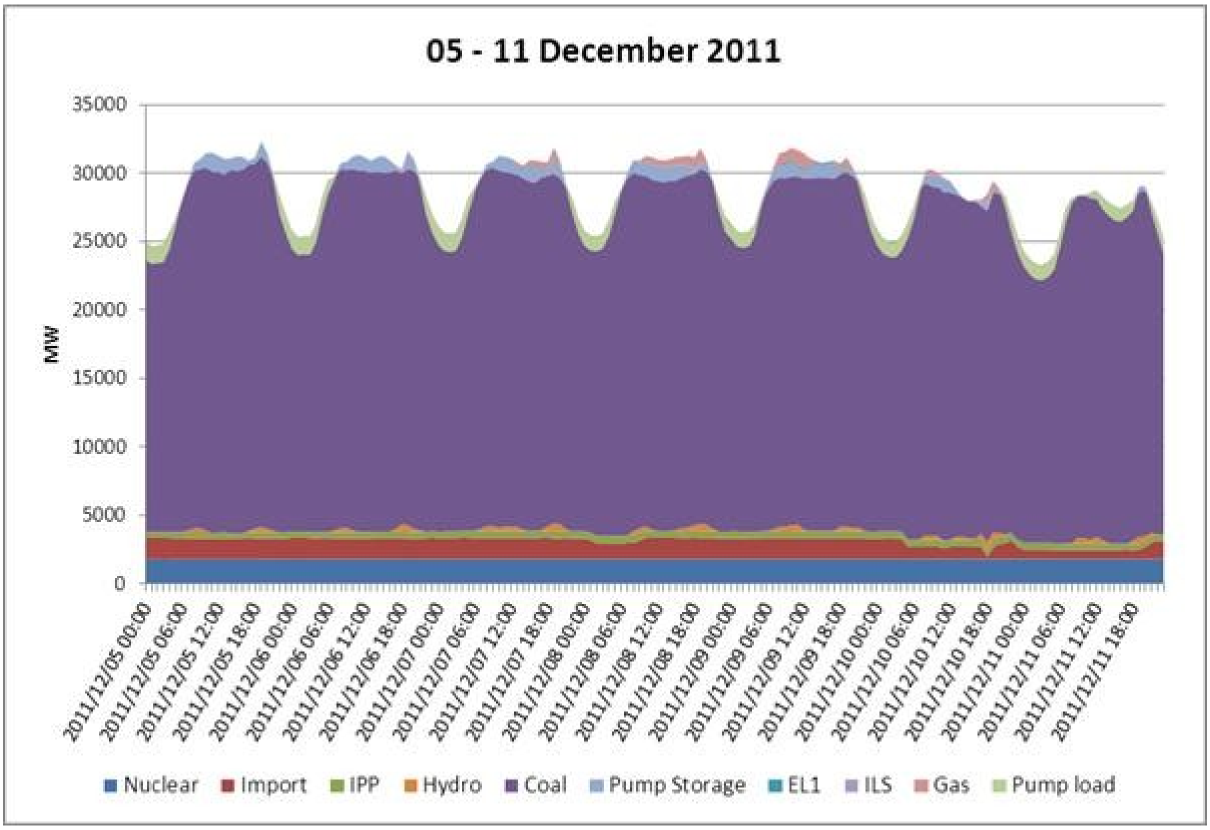

Figure 22: Generation mix during December 2011 - Week 2

During the third week of December 2011, EL1 was utilised on five occasions, again due to a general shortage of supply. On one occasion 437 MW of ILS was needed to arrest the frequency decay after Majuba Unit 4 tripped from 300 MW shortly after EL1 was declared as per the emergency reserve deployment merit order. Gas turbines were also used during this week as part of the emergency resources. The weekly profile for the third week of December 2011 can be seen in Figure 23.

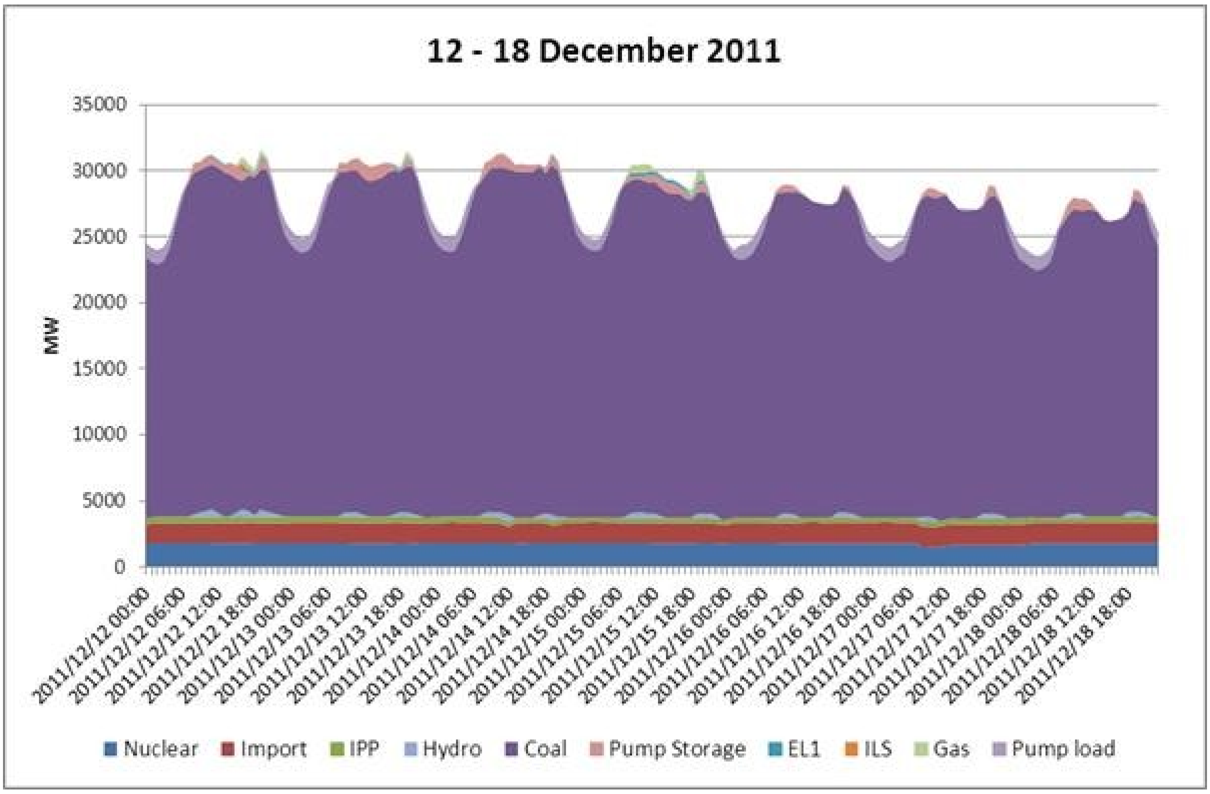

Figure 23: Generation mix during December 2011 - Week 3

During the fourth week of December 2011, EL1 was utilised on two occasions due to a general shortage of supply. The use of ILS was needed on three occasions. The first time 150 MW of ILS was needed when Lethabo Unit 4 tripped from 593 MW. The tripping of Lethabo Unit 4 also resulted in one of the EL1 events being initiated. The second time, 600 MW of ILS was needed when electrical energy import at Apollo Converter Station was suddenly reduced by 860 MW due to the loss of generation at Songo. Two pot lines were needed, making up the 600 MW of ILS to arrest the frequency during this event. The third time, 587 MW of ILS was needed when Majuba Unit 6 tripped from 696 MW. Again, two pot lines were needed at the time to arrest the frequency decay. The weekly profile for the fourth week of December 2011 can be seen in Figure 24.

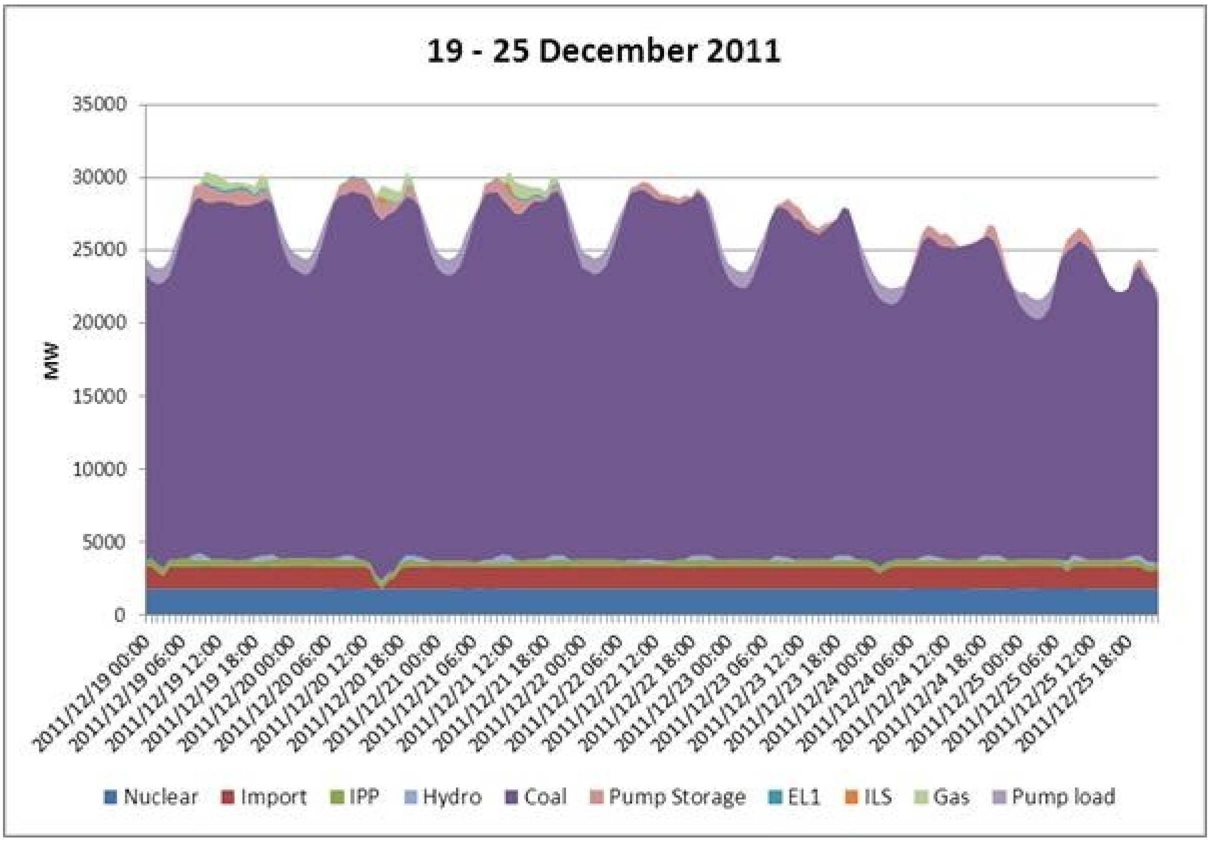

Figure 24: Generation mix during December 2011 - Week 4

During the fifth week of December 2012, EL1 was utilised on four occasions due to a general shortage of supply. One of the occasions was initiated by the loss of 1526 MW of electrical energy import at Apollo Converter Station at 18:41 on the 27th when all generation at Songo was lost. The loss of electrical energy import at Apollo Converter Station could not have happened at a worse time during that day as it was during the hour when the load was at its highest for that day. The loss of generation also resulted in the only LFI for December 2011 where the frequency dropped to 49.188 Hz. During this event, only 150 MW of ILS was utilised to arrest the frequency decay. The weekly profile for the fifth week of December 2011 can be seen in Figure 25.

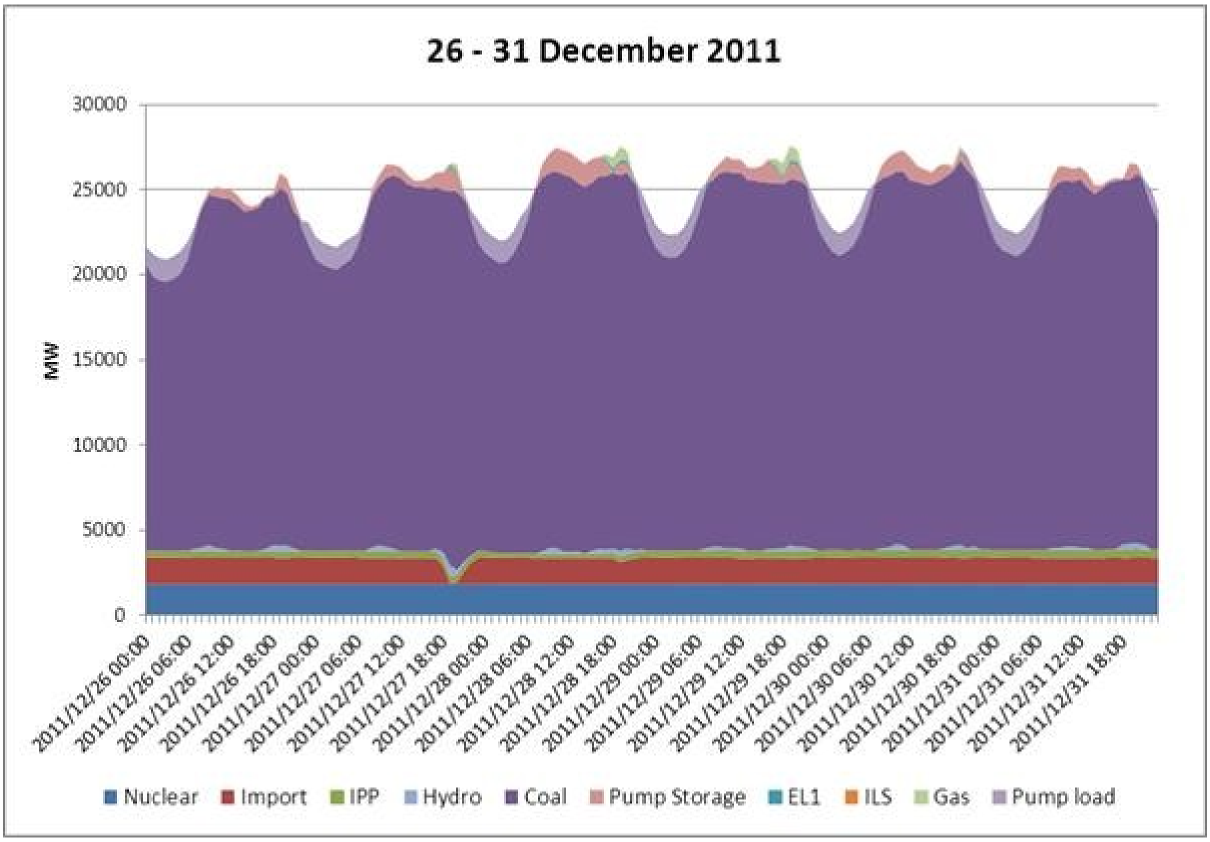

Figure 25: Generation mix during December 2011 - Week 5

5.2.4 Actual weekly generation mix during July 2012

During the first week of July 2012, EL1 was utilised on two occasions during evening peaks due to a general shortage of supply. On one occasion the use of EL1 was not sufficient and gas turbines as well as 150 MW of ILS were also needed to arrest the frequency decay.

On three occasions electrical energy imports at Apollo Converter Station were reduced on National Control's request to cater for night minimum conditions. During the first occasion Apollo was requested to reduce 780 MW from 00:12 to 05:02 on the 1st of July. During the second occasion Apollo was requested to reduce 870 MW from 00:50 to 05:45 on the 2nd of July. During the third occasion Apollo was requested to reduce 300 MW from 23:20 to 02:05 on the 7th of July.

The weekly profile for the first week of July 2012 can be seen in Figure 26.

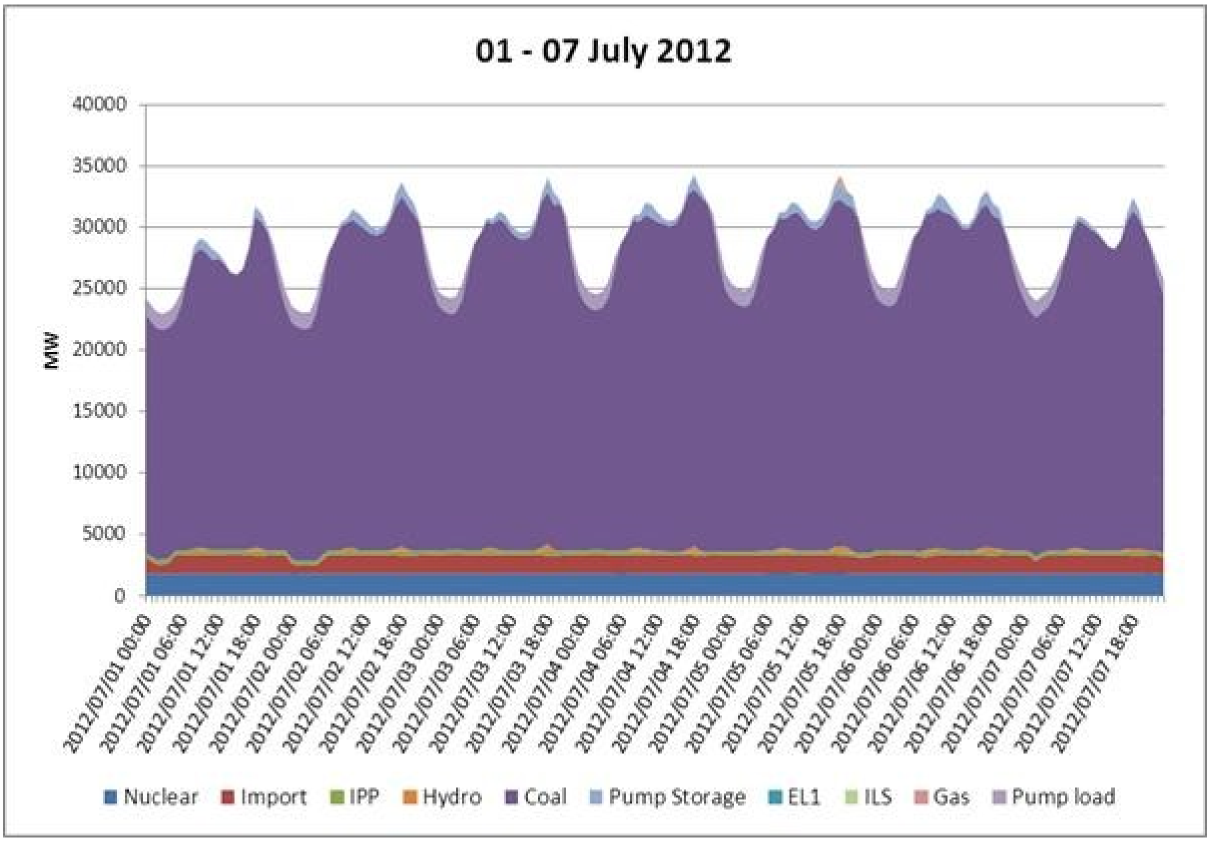

Figure 26: Generation mix during July 2012 - Week 1

During the second week of December 2012, EL1 was utilised on seven occasions due to a general shortage of supply. For all these occasions, gas turbines were also needed to meet the demand as part of the emergency resources. On one of the occasions 1066 MW of ILS was also needed to arrest the frequency decay when Koeberg Unit 1 tripped from 920 MW. On another occasion 608 MW of ILS was required to arrest the frequency decay when electrical energy import at Apollo was suddenly reduced by 198 MW, together with an Arnot Unit 6 that tripped at the same time.

On three occasions electrical energy imports at Apollo Converter Station were reduced on National Control's request to cater for night minimum conditions. During the first occasion Apollo was requested to reduce 1000 MW from 02:05 to 07:26 on the 8^{th} of July. During the second occasion Apollo was requested to reduce 800 MW from 01:00 to 04:14 on the 9^{th} of July. During the third occasion Apollo was requested to reduce 400 MW from 02:30 to 04:56 on the 11^{th} of July.

The weekly profile for the second week of July 2012 can be seen in Figure 27.

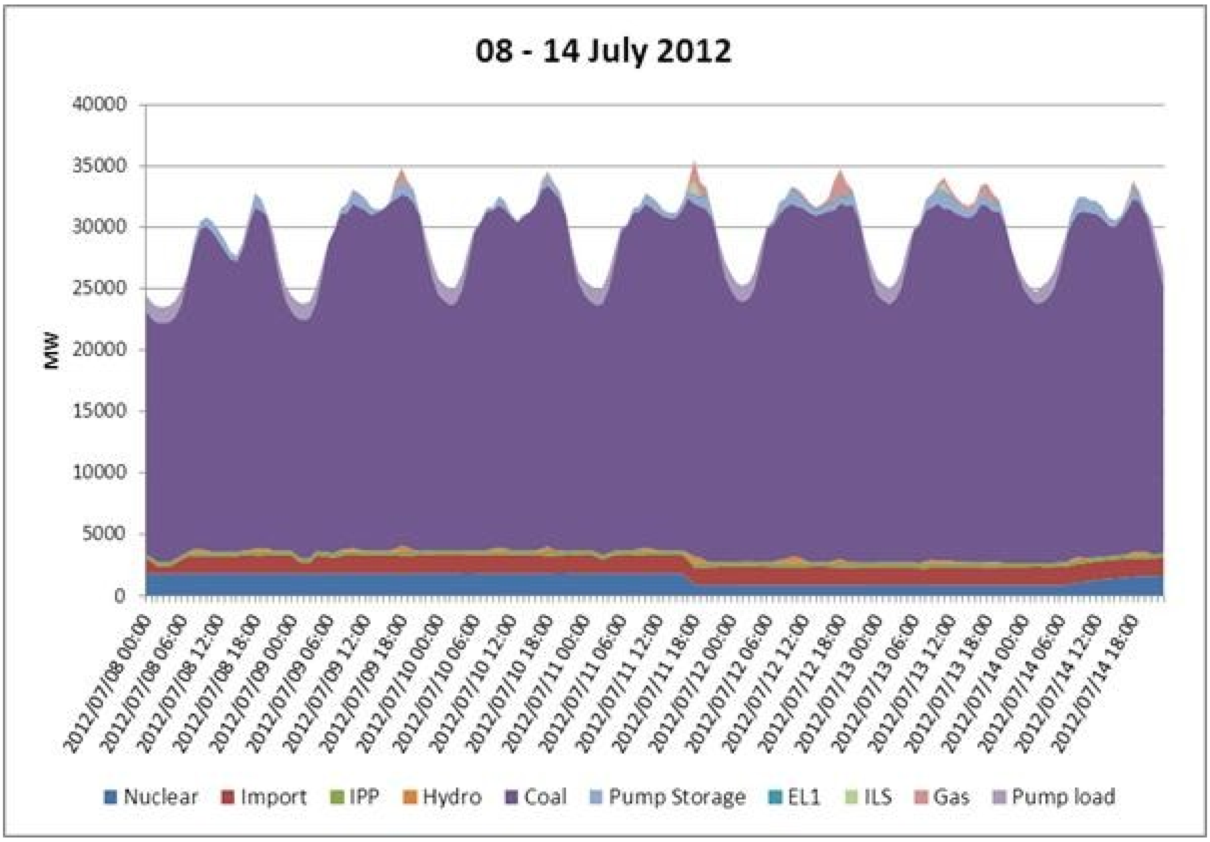

Figure 27: Generation mix during July 2012 - Week 2

During the third week of July 2012, EL1 was utilised on five occasions, again due to a general shortage of supply. For all these occasions, gas turbines were also needed to meet the demand as part of the emergency resources. The weekly profile for the third week of July 2012 can be seen in Figure 28.

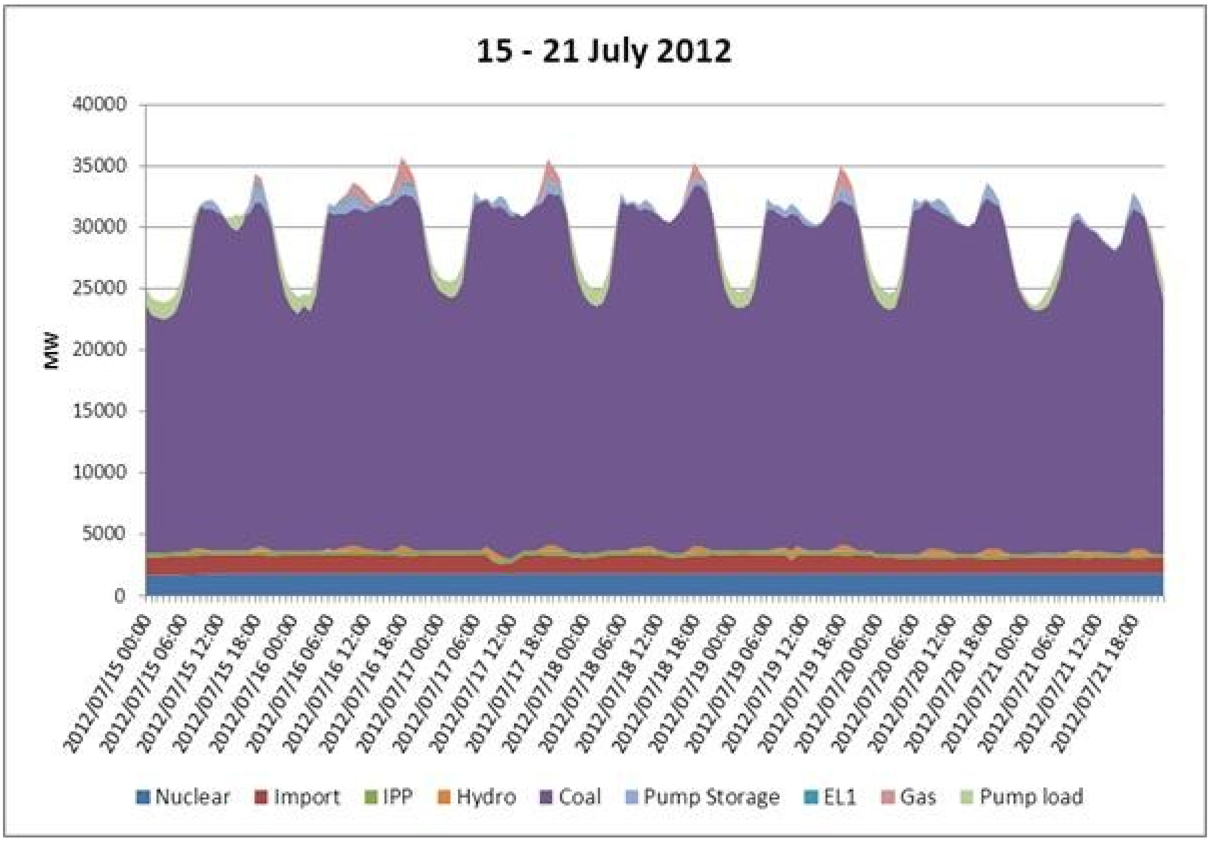

Figure 28: Generation mix during July 2012 - Week 3

During the fourth week of July 2012, EL1 was utilised on six occasions, again due to a general shortage of supply. For all but one of these occasions, gas turbines were also needed to meet the demand as part of the emergency resources. Electrical energy imports at Apollo Converter Station reduced during this week due to a reactor that faulted at Songo. The weekly profile for the fourth week of July 2012 can be seen in Figure 29.

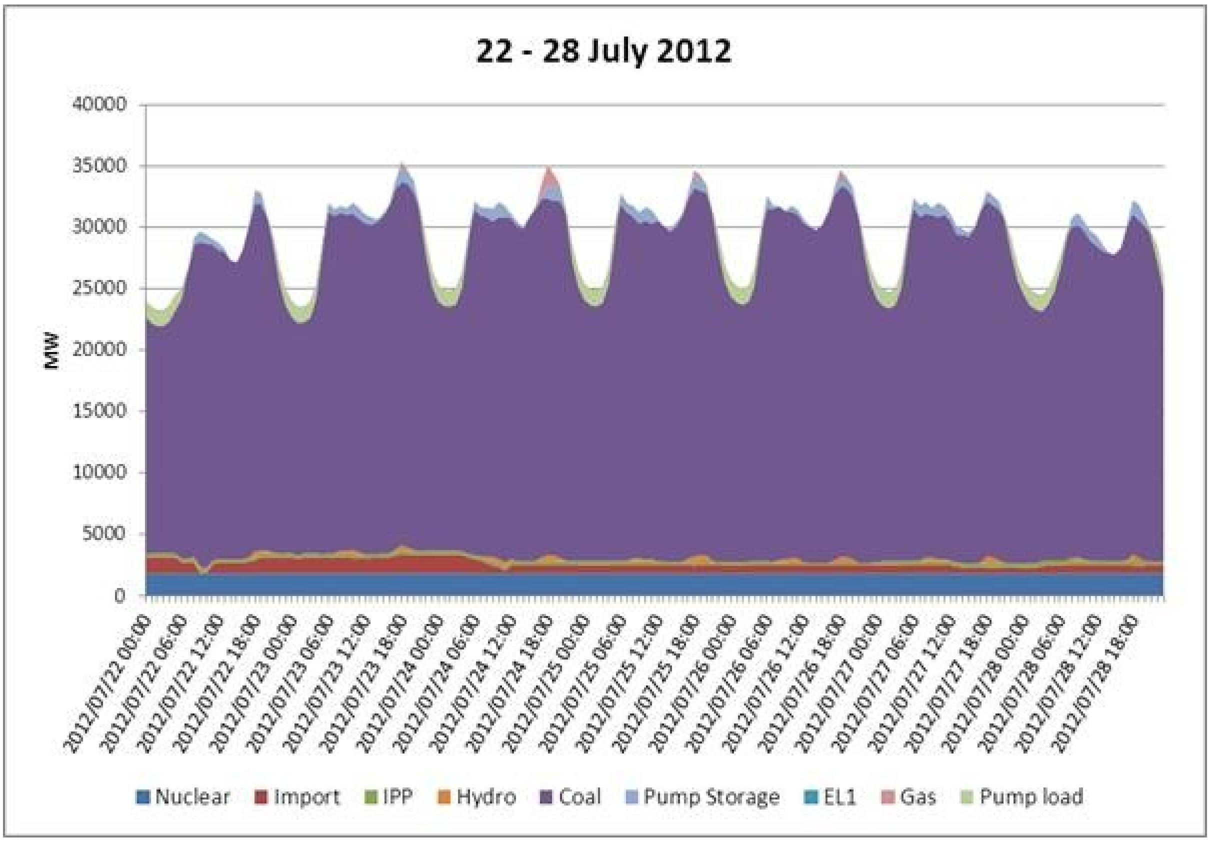

Figure 29: Generation mix during July 2012 - Week 4

During the fifth week of July 2012, EL1 was utilised on two occasions, again due to a general shortage of supply. For both these occasions, gas turbines were also needed to meet the demand as part of the emergency resources. The weekly profile for the fifth week of July 2012 can be seen in Figure 30.

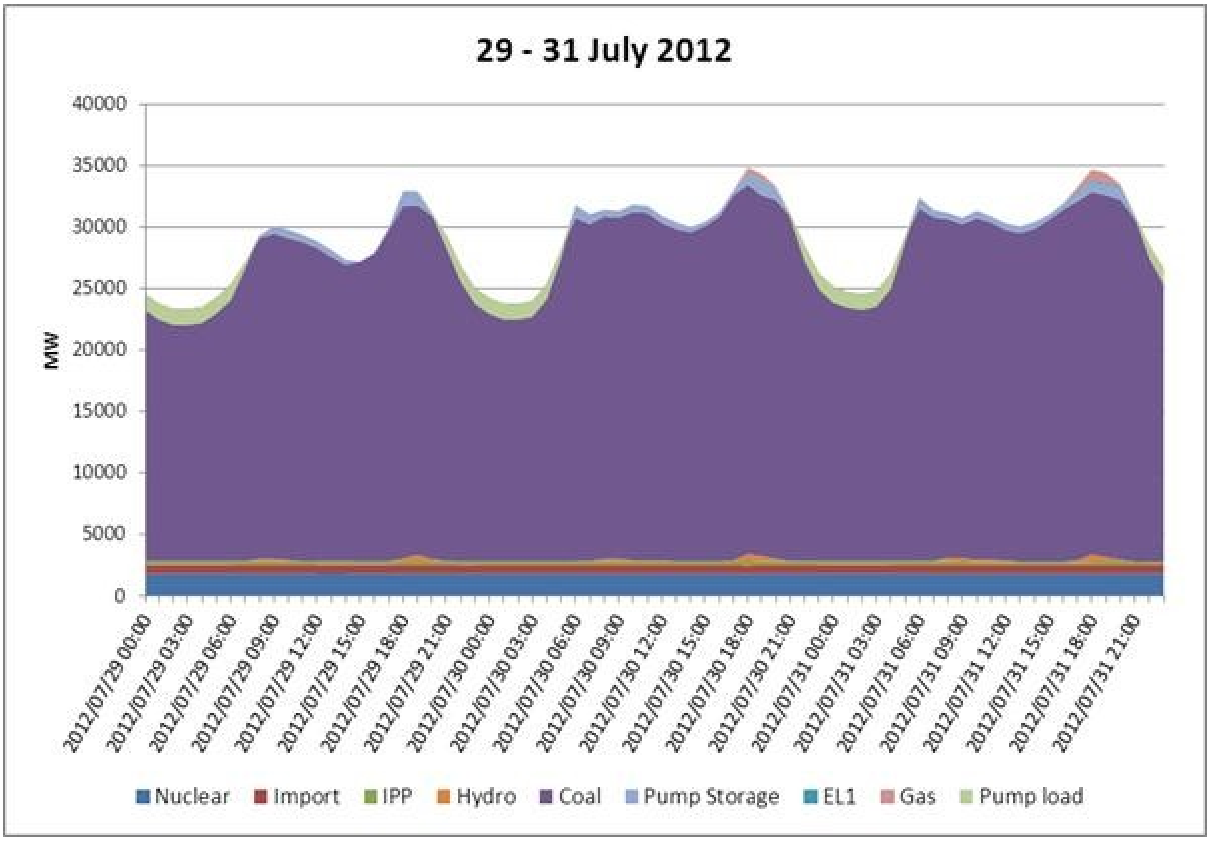

Figure 30: Generation mix during July 2012 - Week 5

5.3 Wind power output

The fact that data from only seven out of ten wind measurement stations of the WASA project was used effectively reduces the number of wind farms from sixteen to seven. These new wind farms will now be referred to as Wind farms A to G. The total capacity of the wind farms remains unchanged at 1296.5 MW.

Wind farm A with a capacity of 100 MW represents Eskom's Sere wind farm of which the wind speed data was sourced from WASA wind mast 3.

Wind farm B with a capacity of 291.4 MW represents wind farm 1, 8 and 12 of which the wind speed data was sourced from WASA wind mast 4.

Wind farm C with a capacity of 26.2 MW represents wind farm 4 of which the wind speed data was sourced from WASA wind mast 5.

Wind farm D with a capacity of 72.7 MW represents wind farm 2 of which the wind speed data was sourced from WASA wind mast 7.

Wind farm E with a capacity of 415.6 MW represents wind farm 5, 6, 7, 11, 13 and 14 of which the wind speed data was sourced from WASA wind mast 8.

Wind farm F with a capacity of 369.9 MW represents wind farm 3, 9 and 10 of which the wind speed data was sourced from WASA wind mast 9.

Wind farm G with a capacity of 20.6 MW represents wind farm 15 of which the wind speed data was sourced from WASA wind mast 10.

5.3.1 Ten-minute average wind power output during December 2011

A graphical representation of the combined ten-minute average wind power output for December 2011 can be seen in Figure 31.

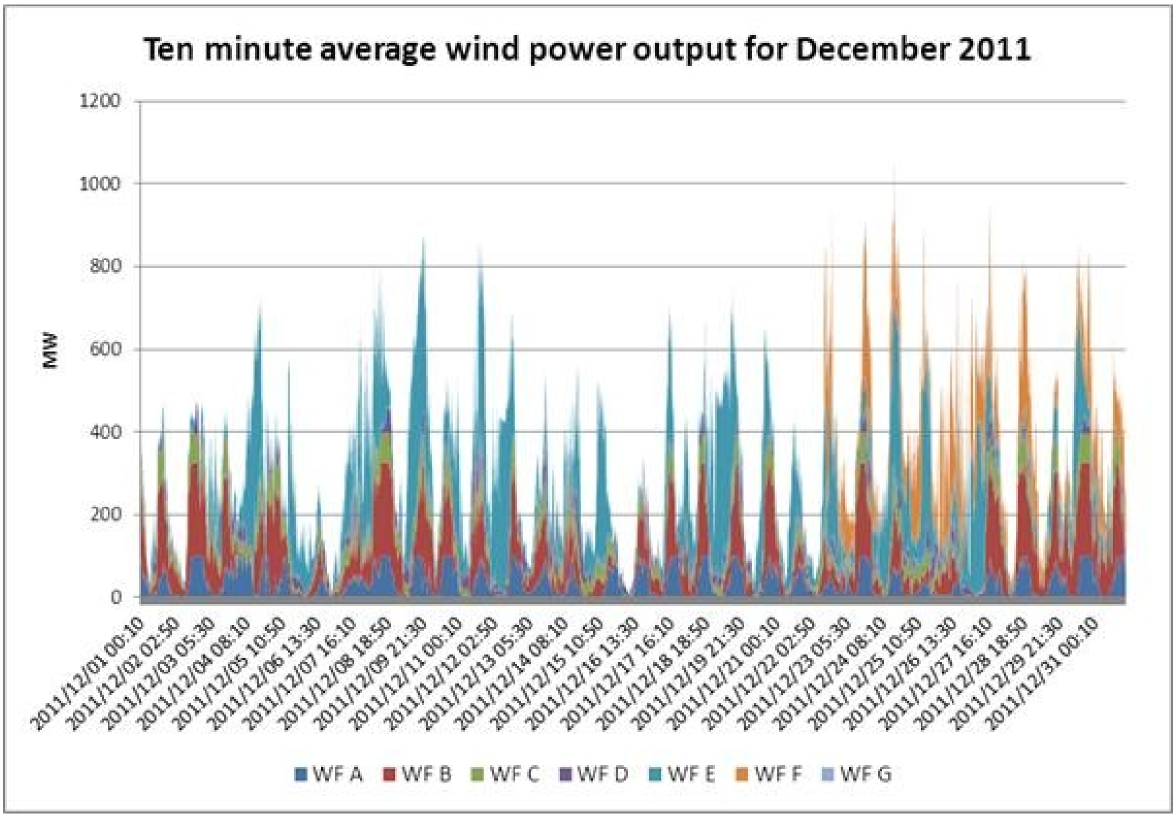

Figure 31: Combined ten-minute average wind power output for December 2011

The maximum ten-minute integrated output from the wind farms combined would have occurred at 16:40 on the 24th of December and would have been 1106.1 MW representing 85.3% of the wind farms' maximum capability. The maximum hourly integrated output from the wind farms combined would have been 949.1 MW for the hour ending 17:00 also on the 24th of December. Wind power generation would only have covered 3.7% of the total load at the time.

The minimum output from wind would have been 8.28 MW. The wind farms would have produced a total of 247 GWh of electrical energy during December 2011 had they been online.

The use of the emergency resources would have been significantly less during December 2011 had the wind power been online. The total amount of emergency generated electrical energy would have reduced from 78.5 GWh to 28.6 GWh, a reduction of 63.6%.

5.3.2 Ten-minute average wind power output during July 2012

A graphical representation of the combined ten-minute average wind power output for July 2012 can be seen in Figure 32.

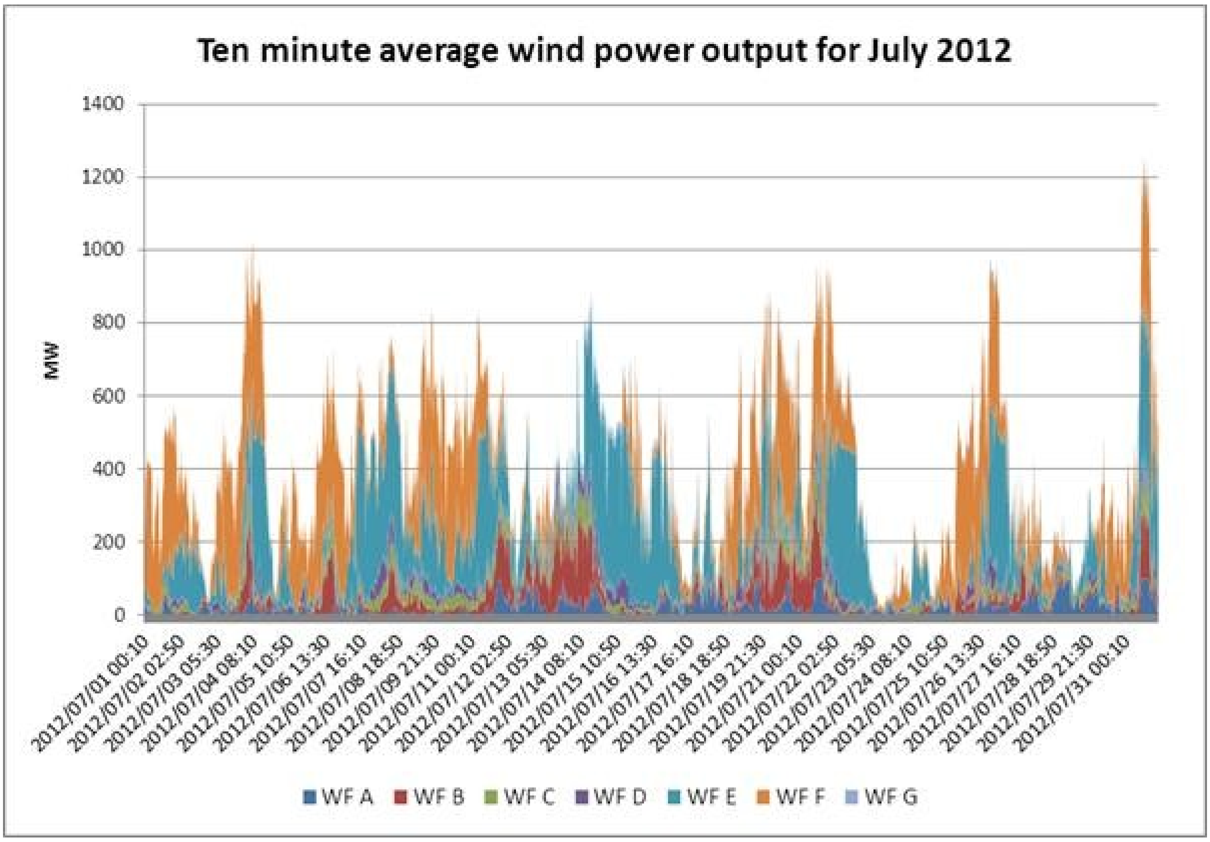

Figure 32: Combined ten-minute average wind power output for July 2012

The maximum ten-minute integrated output from the wind farms combined would have occurred at 13:40 on the 31st of July and would have been 1267.3 MW representing 97.7% of the wind farms' maximum capability. The maximum hourly integrated output from the wind farms combined would have been 1205.8 MW for the hour ending 16:00 also on the 31st of July. Wind power generation would only have covered 3.78% of the total load at the time.

The minimum output from wind would have been 14.63 MW. The wind farms would have produced a total of 298.2 GWh of electrical energy during July 2012 had they been online.

Again the use of the emergency resources would have been significantly less during July 2012 had the wind power been online. The total amount of emergency generated electrical energy during July 2012 would have reduced from 70.1 GWh to 37.8 GWh, a reduction of 46.04%.

Of the 298.2 GWh wind produced energy, 17.7 GWh would have been unwanted as it would have been produced during times when there was surplus generation on line. During these times the only option left for National Control to have maintained the balance between demand and supply was to reduce electrical energy imports at Apollo converter station. More expensive generating units could not have been taken off line for it would not have been possible to return them to service in time for the following morning peak. This, however, would have happened at a time when Majuba experienced technical problems and was not able to two-shift its units.

5.3.3 Wind farm ramp rates during December 2011

The ten-minute ramp rates of wind farms A to G as well as their ramp rates in percentage relative to their capacities for December 2011 are given in Table 25.

Table 25: Wind farm ramp rates for December 2011

Wind Farm	Capacity (MW)	Ramp Rate Upwards (MW/10 min)	% Ramp Rate Upwards (%)	Ramp Rate Downwards (MW/10 min)	% Ramp Rate Downwards (%)
A	100.0	75.5	75.5	52.5	52.5
B	291.4	176.8	60.7	141.2	48.4
C	26.2	13.6	52.0	14.1	54.0
D	72.7	60.8	83.6	47.2	64.9
E	415.6	393.2	94.6	256.4	61.7
F	369.9	356.6	96.4	319.7	86.4
G	20.6	17.6	85.5	18.4	89.2
Total	1296.5	400.4	30.9	303.8	23.4

The highest upward ramp rate in terms of percentage change relative to its capacity was achieved by wind farm F. On the 25th of December, the power output of wind farm F changed from a mere 11.8 MW at 15:10 to almost full power output of 356.6 MW at 15:20 representing a change of 96.4% of its total capacity.

The highest downward ramp rate in terms of percentage change relative to its capacity was achieved by wind farm G. On the 22nd of December, the power output of wind farm G changed from almost full power at 19.3 MW at 02:20 to an output of 0.9 MW at 02:30 representing a change of 89.2% of its total capacity.

The highest upward ramp rate for the wind farms combined would have been 400.4 MW per ten minutes. In terms of percentage change relative to their total capacity, it would have been 30.9%, lower than any of the individual upward ramp rates. The highest downward ramp rate for the wind farms combined would have been 303.8 MW per ten minutes. In terms of percentage change relative to their total capacity, it would have been 23.4%, again lower than any of the individual downward ramp rates.

A graphical representation of the would-be wind power ramp rates of December 2011 is shown in Figure 33.

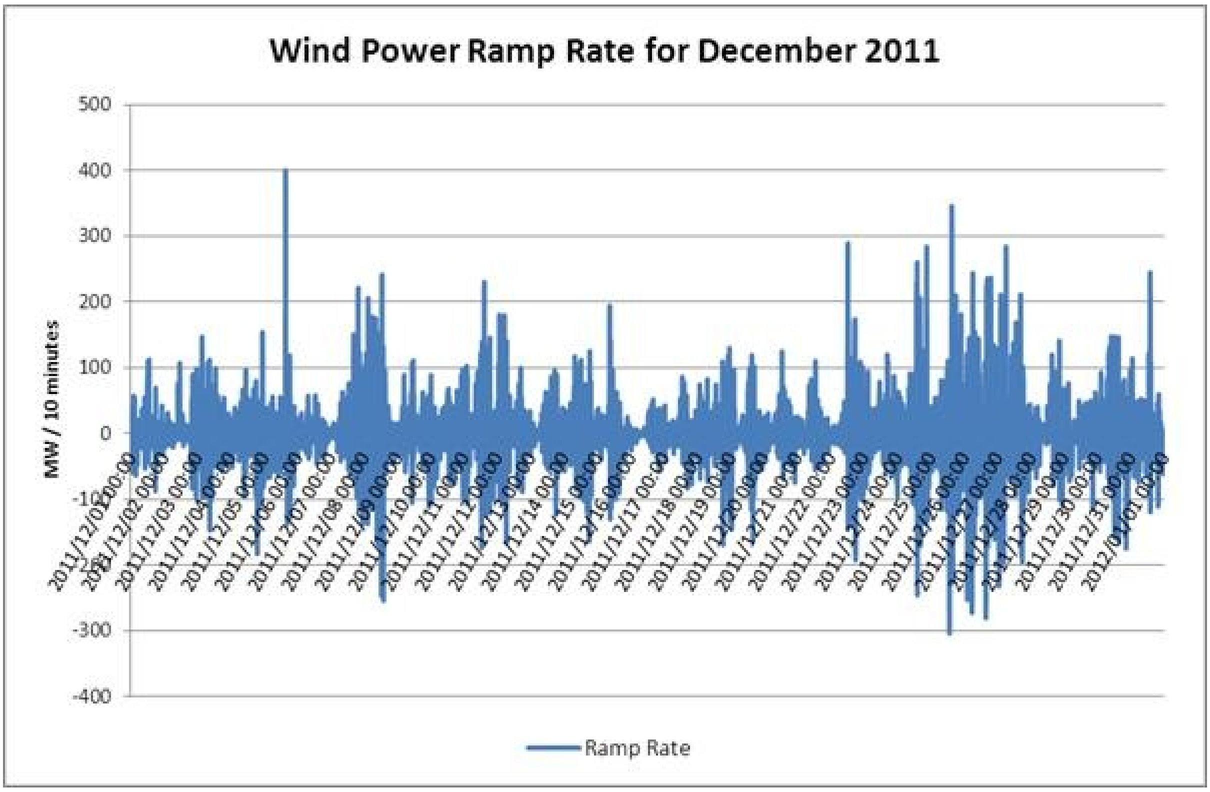

Figure 33: Ten-minute ramp rate for December 2011 wind power output

5.3.4 Wind farm ramp rates during July 2012

The ten-minute ramp rates of wind farms A to G as well as their ramp rates in percentage relative to their capacities for July 2012 are given in Table 26.

Table 26: Wind farm ramp rates for July 2012

Wind Farm	Capacity (MW)	Ramp Rate Upwards (MW/10 min)	% Ramp Rate Upwards (%)	Ramp Rate Downwards (MW/10 min)	% Ramp Rate Downwards (%)
A	100.0	57.3	57.3	56.0	56.0
B	291.4	170.5	58.5	224.3	77.0
C	26.2	18.3	69.8	18.3	70.0
D	72.7	41.0	56.4	48.6	66.9
E	415.6	394.7	95.0	254.8	61.3
F	369.9	160.0	43.3	191.8	51.8
G	20.6	14.7	71.3	12.6	61.3
Total	1296.5	386.6	29.8	266.0	20.5

The highest upward ramp rate in terms of percentage change relative to its capacity was achieved by wind farm E. On the 14th of July, the power output of wind farm E changed from a mere 20.9 MW at 10:40 to full power output of 415.6 MW at 10:50 representing a change of 95% of its total capacity.

The highest downward ramp rate in terms of percentage change relative to its capacity was achieved by wind farm B. On the 31st of July, the power output of wind farm B changed from full power at 291.4 MW at 13:40 to an output of 67.05 MW at 13:50 representing a change of 77% of its total capacity.

The highest upward ramp rate for the wind farms combined would have been 386 MW per ten minutes. In terms of percentage change relative to their total capacity, it would have been 29.8%, lower than any of the individual upward ramp rates. The highest downward ramp rate for the wind farms combined would have been 266.02 MW per ten minutes. In terms of percentage change relative to their total capacity, it would have been 20.5%, again lower than any of the individual downward ramp rates.

A graphical representation of the would-be wind power ramp rates of July 2012 is shown in Figure 34.

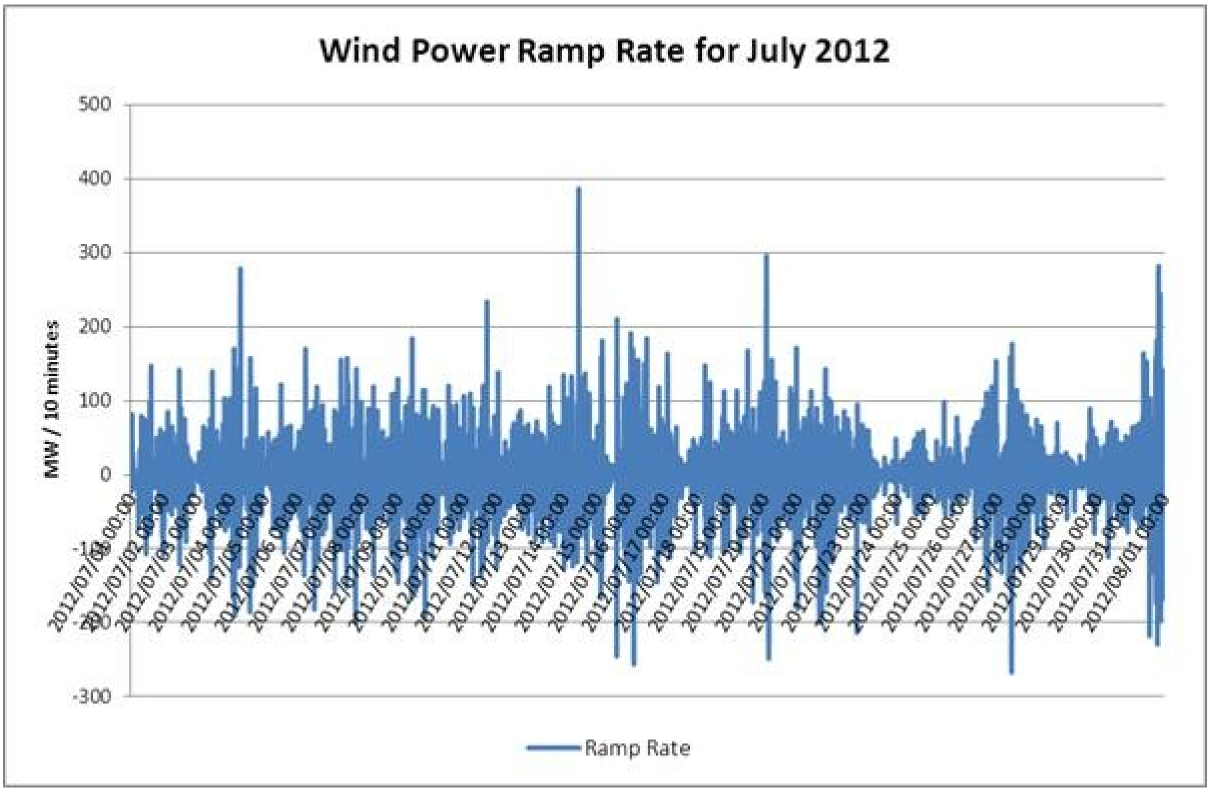

Figure 34: Ten-minute ramp rate for July 2012 wind power output

For both the months of December 2011 and July 2012 upward as well as downward ramp rates in terms of percentage change relative to its capacity for the wind farms combined were significantly lower than ramp rates from individual wind farms. This implies that spreading the wind farms geographically has a significant smoothing effect, reducing the variability introduced by a single wind farm.

5.3.5 Ramp rates during Low Frequency Incidents

During the time of the LFI that occurred at 18:41 on the 27th of December 2011, the ramp rate from the wind power would have been an upwards 83.7 MW per ten minutes. Consequently it would have reduced the severity of the LFI had wind power already been online.

During the time of the first LFI that occurred at 17:36 on the 11th of July 2012, the ramp rate from the wind power would have been an upwards 59.86 MW per ten minutes. Consequently it would have reduced the severity of the LFI had wind power already been online.

During the time of the second LFI for July 2012 that occurred at 10:21 on the 13th, the ramp rate from the wind power would have been a downward 13.28 MW per ten minutes. This time the severity of the LFI would have been worse had wind power already been online.

5.4 Conclusion

Eskom's gas turbines are seen as an emergency resource and under normal conditions should not be used for peaking purposes as is the case in most other countries. On the other hand and in contrast to most other countries, Eskom's coal fired power stations also act as intermediate power plants to meet the demand. It is thus normal for Eskom's coal fired power stations to be ramped up and down to follow the load. The study shows that ramp rates from wind power generation should be lower than the ramp rates currently experienced on the Eskom network.

Although the demand for electrical energy is much lower during summer times, (19.9 TWh during December 2011 compared to 21.5 TWh during July 2012), the use of emergency resources during December was still required to meet the demand. This is due to the fact that Eskom uses the low loading conditions of summer to maintain its fleet of power plants. This is also evident from the figures in Table 23 and Table 24 where it can be seen that the percentage contribution of coal generated power towards the overall generation mix was the only figure that went up from December 2011 to July 2012. The percentage contribution for all the other generation technologies, including gas turbines, was lower for July 2012.

For both the months of December 2011 and July 2012 the use of the emergency resources would have been significantly less had the wind power been online. However, there also would have been times when the wind generation would have been unwanted.

It can also be concluded that spreading the wind farms geographically has a significant smoothing effect, reducing variability introduced by a single wind farm.

The following chapter concludes the research and give recommendations based on what has been discussed.

Chapter 6

This chapter concludes the dissertation and gives recommendation based on what has been discussed.

Chapter 6 Conclusion and recommendations

6.1 Conclusion

The introduction of non-dispatchable renewable energy to the South African electrical network is non-negotiable. Both wind and solar can be considered intermediate power sources. Both are intermittent by nature, as output fluctuates with weather patterns. Wind and solar cannot be relied upon to meet constant supply needs, nor can they be immediately called upon to meet peak demands. They are, however, effective as intermediate sources and can help to reduce the need for fossil fuel intermediate plants, overuse of peaking plants and use of emergency resources during heavy demand periods. However, the tariffs that Eskom will pay towards these generating resources, ranging between 80 cents per kWh and 285 cents per kWh, are high in comparison with Eskom's average operating cost for electrical energy, which currently is around 41.3 cents per kWh.

Eskom's current regulating reserve requirements will be adequate to cater for the integration of variable RE generation into the South African electrical network according to the capacities allocated by the DoE in the first two rounds of the RE IPP Procurement Programme.

Eskom's regulating reserve requirements are to have available 600 MW of regulation upwards as well as 600 MW of regulation downwards at all times. It does not specify a minimum number of generating units that must be available for regulating, but does specify that a regulating unit must be able to change its generation by at least 1.67% of its maximum continuous rating per minute. Generators typically bid in to have 60 MW of regulation available in both directions. Consequently, under normal conditions there will always be in the order of ten generators regulating at a time to give a total ramp rate in the order of 100 MW per minute or a 1000 MW per ten minutes. Other than the thermal regulating units, Eskom also currently has two pumped storage generating plants available totalling 1400 MW that are capable of handling load variations of 80 MW per minute per unit.

From the study the highest upward ramp rate due to wind generation would have been 400.4 MW per ten minutes with the highest downward ramp rate 303.8 MW per ten minutes.

Through spreading the wind farms geographically, the aggregated output will be smoother than if the wind farms were all clustered closely together.

Instead of having ramp rates of up to 96.41% of a wind farm's total capacity upwards per ten minutes and 89.25% downwards, through geographically spreading out the wind farms the upwards and downwards ramp rates reduced to 30.88% and 23.43% respectively.

Historically, and in particular during December 2011 and July 2012 being the periods of concern for the study, Eskom was required to utilise emergency resources to meet system demand. During these periods the extra generation from wind would have been of benefit.

Eskom is finding itself in a predicament where it is operating with a very small reserve margin to the extent that Eskom finds it difficult to take generating units off line for maintenance purposes. Consequently, any extra generating capacity will presently be welcomed on the grid even if it were variable non-dispatchable generation.

The study showed that the total amount of emergency generated electrical energy during December 2011 and July 2012 would have reduced from 148.6 GWh to 66.4 GWh, a reduction of 55.3%, had wind been online. The use of the emergency resources would not have been avoided in total, but their use would have been a lot less had the wind generation been online. Also, for two out of the three low frequency incidents that occurred during the periods of concern, wind power generation would have been busy ramping upwards during the times of the incidents. Hence, it would have reduced the severity of the incidents.

RE generation would have contributed to unwanted energy during times when Eskom was running with surplus generation.

Of the 545.2 GWh of wind produced electrical energy during the months of December 2011 and July 2012, only 17.7 GWh representing 3.25% would have been unwanted as it would have been produced during times when there was surplus generation on line. This, however, would have happened at a time when technical problems were being experienced at Majuba power station and Majuba was not able to two-shift its units.

6.2 Recommendations

From a frequency balancing point of view, it is recommended for Eskom to build in contractual limitations when it comes to the ramp rates of individual wind farms. As a safety measure it can be recommended to always have some scope of regulation available in both directions at Eskom's pumped storage power plants. At both Drakensberg and Palmiet pumped storage schemes, it is possible for each of the units to generate at 50 MW less than its full power output. Through doing this Eskom can ensure that, between the two pumped storage stations, there will be a total of 300 MW instantly available for upwards regulation under extreme conditions.

It is further recommended that Eskom ensures that its two-shifting units are at all times technically fit for two-shifting. This will ensure that Eskom will not make use of wind energy generation at the cost of its cheapest resources.

It is also recommended for Eskom's load forecasters to start forecasting net-load and not only the load as is the current practice. The net-load is the normal load less the generation from non-dispatchable RE sources. Consequently, it is recommended for Eskom to invest in wind forecasting tools.

6.3 Recommendations for further research

The study only looked at the balancing challenge introduced through non-dispatchable renewable generation that will be integrated into the South African electrical network according to the first two rounds of the DoE's RE IPP Procurement Programme. It is recommended that the effect of the additional RE from subsequent rounds of the DoE's RE IPP Procurement Programme also gets investigated.

Voltage stability and network adequacy were not studied. An in depth analysis of voltage stability and network adequacy together with a study to determine how much non-dispatchable RE can safely be allowed within Eskom with Eskom's current resources is also to be recommended.

If Eskom wants to make use of the additional RE generation that is coming on line to get more maintenance done on its fleet of generating units, a more detailed study is required to determine exactly how much generation can safely be replaced by the use of emergency resources.

The study only made use of wind data from the actual wind measuring stations of the WASA project. For further studies the WASA project's virtual masts should be used to obtain wind data for the wind farms according to their locations.

The study also only analysed two months' worth of data. In order to get an understanding of the seasonal changes of wind and its effect to the Eskom network, it is recommended to increase the time period of the study to cover at least a year's worth of data.

Bibliography

About Wind Atlas for South Africa. 2012. http://www.wasaproject.info/about-wasa/ Date of access: 10 September 2012.

ASH, M, CURRIE, S, DE WET, T, JACKSON, J, MIDLANE, J, NOETH, G & ROSE, N. 2011. Legal Library Article: South Africa Renewable Energy IPP Request for Proposals. Date of access: 07 July 2012. <http://www.martindale.com/energy-law/article_Norton-Rose-OR-LLP_1328854.htm>

BASS, R W. 2007. *Is the Albert Betz Law stating the maximum wind turbine efficiency of 16/27's accurate? Correcting the Betz Limit with better momentum flux theory*.

BINNEMAN, R. 2012. *32-636: System Operations Generation Scheduling*. Germiston, South Africa.

CENTER FOR POLITISKE STUDIER. 2009. *Wind Energy - The case of Denmark*. Copenhagen.

CHANG-CHIEN, L, LIN, Y & WU, C. 2007. An online evaluation of operating reserve for system security. *World Academy of Science, Engineering and Technology*, 28:231-236.

CORDARO, M. 2008. *Understanding base load power - What it is and why it matters*. New York.

CSIR. 2010. CSIR online. Date of access: 14 September 2012. <http://stel-apps.csir.co.za/wasa-img/WASA_Instruments.pdf>

DANISH ENERGY AGENCY. 2010. *Energy in Denmark - Presentation*.

DANISH ENERGY AGENCY. 2011. Annual Energy Statistics. http://www.ens.dk/en-US/Info/FactsAndFigures/Energy_statistics_and_indicators/Annual%20Statistics/Sider/Forside.aspx Date of access: 2 June 2012.

DEAN, J. 2008. *Operation of Drakensberg pumped storage scheme*. Germiston, South Africa.

DEAN, J. 2009. *SPC46-7: Certification and performance monitoring of generation reserves*. Germiston, South Africa.

Bibliography

DEPARTMENT OF ENERGY - REPUBLIC OF SOUTH AFRICA. 2011. *Integrated Resource Plan for Electricity (2010 - 2030)*.

DEPARTMENT OF ENERGY - REPUBLIC OF SOUTH AFRICA. 2011. Speeches and Statements. Date of access: 24 September 2012. <http://www.info.gov.za/speeches/docs/2011/reippp.pdf>

DEPARTMENT OF ENERGY - REPUBLIC OF SOUTH AFRICA. 2012. Announcement of the preferred bidders of the renewable energy independent power producers procurement programme window 2. http://www.info.gov.za/speech/DynamicAction?pageid=461&sid=27564&tid=68891 Date of access: 8 July 2012.

DEPARTMENT OF ENERGY - REPUBLIC OF SOUTH AFRICA. 2012. Preferred bidders - Window 2. http://www.ipprenewables.co.za/#blog/post/view/id/182 Date of access: 31 August 2012.

DEPARTMENT OF MINERALS AND ENERGY. 2003. *White paper on renewable energy*. Republic of South Africa.

EA ENERGY ANALYSES. 2011. *GIZ sponsored workshop on mapping the RFI and grid issues related to connecting wind turbines*. Copenhagen.

ENERGINET.DK. 2010. *Anciliary services to be delivered in Denmark tender conditions*.

ESKOM. 2012. *Renewable Energy Integration Training - Denmark*.

ESKOM HOLDINGS SOC LIMITED. 2012. *Integrated Report for the year ended 31 March 2012*. Sunninghill, Sandton, South Africa.

ESKOM HOLDINGS SOC LIMITED. 2012. *Standard Presentation*.

Europe's Energy Portal. 2011. http://www.energy.eu/#domestic Date of access: 6 June 2012.

INTERNATIONAL ENERGY AGENCY. 2011. Harnessing variable renewables - A guide to the balancing challenge. Paris, France: International Energy Agency.

KERNAN, A. 2012. Policy forum: From REFIT to REBID: South Africa's renewable energy auctions. http://cleanenergysolutions.org/blogs/128/refit-rebid-south-africas-renewable-energy-auctions Date of access: 8 July 2012.

Bibliography

LUND, T. 2011. *Renewable energy integration training - Denmark*.

MTOLO, D & EDWARDS, A. 2012. *Instantaneous reserve studies for 2012*. Germiston, South Africa.

NATIONAL ENERGY REGULATOR OF SOUTH AFRICA. 2008. *The South African Grid Code*. Arcadia.

NERSA. 2011. *Review of Renewable Energy Feed-In Tariffs*. Pretoria, South Africa.

NTUSI, M. 2011. *SOPPC0008: Control of system frequency under normal and abnormal conditions*. Germiston, South Africa.

NTUSI, M. 2011. *SOPST0004: Measurement and recording of Eskom frequency*. Germiston, South Africa.

NTUSI, M. 2011. *SPC 46-2: Short term energy reserve procedure*. Germiston, South Africa.

ORGANISATION FOR ECONOMIC CO-ORPERATION AND DEVELOPMENT. 2011. OECD Factbook. http://www.oecd-ilibrary.org/economics/oecd-factbook_18147364 Date of access: 6 June 2012.

SEBELA, P M. 2011. *SOPGL0018: Use of interruptible load and communication with BHP Billiton's aluminium smelters*. Germiston, South Africa: Eskom Operations Planning.

SMITH, V, NTUSI, M & TSHWAGONG, I. 2012. *Ancillary services technical requirements for 2012 - 2017*. Germiston, South Africa.

South African Wind Energy Programme. 2012. http://www.energy.gov.za/files/sawep_frame.html Date of access: 11 September 2012.

SURTEES, R. 2005. *Demand market participation of smaller industrial and commercial customers*. Germiston, South Africa.

Wind turbine design. 2012. http://en.wikipedia.org/wiki/Wind_turbine_design Date of access: 14 October 2012.

Bibliography

Wind Turbine Power Generator Equation Formulas Design Calculator. 2002. http://www.ajdesigner.com/phpwindpower/wind_generator_power.php Date of access: 14 September 2012.

Appendix

Appendix

Wind speed data for December 2011

Table 27: Wind speed data for December 2011 week 1

	WM03	WM04	WM05	WM07	WM08	WM09	WM10
01 December 2011							
Min	1.96	1.82	5.96	4.48	0.23	0.00	0.89
Max	12.59	14.71	12.01	10.40	8.54	0.00	12.84
Ave	8.16	9.11	9.54	7.99	4.05	0.00	5.34
02 December 2011							
Min	0.98	4.57	3.82	0.84	0.23	0.00	3.73
Max	15.77	19.28	11.36	13.90	7.53	0.00	9.70
Ave	8.17	11.20	7.01	5.89	3.44	0.00	6.92
03 December 2011							
Min	1.67	6.48	4.23	1.75	1.77	0.00	2.94
Max	14.09	14.02	13.28	11.74	10.84	0.00	12.23
Ave	8.04	10.03	9.50	6.21	6.05	0.00	7.05
04 December 2011							
Min	1.30	1.40	9.34	1.41	3.83	0.00	1.83
Max	17.31	12.66	19.99	11.94	16.13	0.00	10.03
Ave	10.58	6.48	13.03	6.87	9.74	0.00	5.84

Table 28: Wind speed data for December 2011 week 2

	WM03	WM04	WM05	WM07	WM08	WM09	WM10
05 December 2011							
Min	1.72	2.82	0.83	1.94	0.23	0.00	0.44
Max	14.01	14.14	18.54	11.06	16.21	0.00	12.51
Ave	7.55	9.00	9.34	7.77	5.84	0.00	7.04
06 December 2011							
Min	1.48	0.31	1.99	0.37	0.95	0.00	1.80
Max	10.20	9.74	13.91	12.58	9.15	0.00	16.10
Ave	5.07	5.18	6.45	7.27	5.59	0.00	6.54
07 December 2011							
Min	1.61	0.68	7.02	1.32	2.02	0.00	2.43
Max	10.70	11.86	20.36	13.71	12.40	0.00	10.36
Ave	6.90	7.04	11.95	7.31	7.73	0.00	7.15
08 December 2011							
Min	6.76	6.51	6.11	1.63	0.23	0.00	3.69
Max	20.21	17.78	12.04	12.57	13.65	0.00	12.94
Ave	11.87	12.19	8.33	6.88	8.97	0.00	8.00
09 December 2011							
Min	2.08	1.61	4.97	1.42	1.59	0.00	1.42
Max	13.96	13.76	14.38	12.29	16.19	0.00	13.36
Ave	8.06	8.50	9.88	8.09	9.98	0.00	8.34
10 December 2011							
Min	3.10	5.00	1.16	1.06	1.56	0.00	0.66
Max	17.73	12.13	16.82	11.54	12.36	0.00	17.89
Ave	10.20	9.50	9.37	5.61	7.55	0.00	7.74
11 December 2011							
Min	0.55	0.48	6.84	2.30	4.18	0.00	0.80
Max	12.61	13.81	15.08	15.26	18.69	0.00	11.55
Ave	7.44	7.33	9.92	10.30	9.18	0.00	6.63

Table 29: Wind speed data for December 2011 week 3

	WM03	WM04	WM05	WM07	WM08	WM09	WM10
12 December 2011							
Min	1.56	1.09	2.24	3.01	2.46	0.00	1.71
Max	14.94	13.53	7.92	9.61	16.37	0.00	9.28
Ave	7.84	6.05	4.68	6.12	10.31	0.00	5.70
13 December 2011							
Min	5.05	2.98	2.08	1.53	1.46	0.00	1.08
Max	12.67	11.25	16.51	17.56	9.71	0.00	22.86
Ave	8.37	7.87	9.30	8.80	5.55	0.00	8.36
14 December 2011							
Min	2.97	2.78	5.63	4.69	3.60	0.00	1.00
Max	13.29	13.65	18.53	19.52	11.68	0.00	15.44
Ave	7.17	7.61	13.70	10.54	7.50	0.00	6.37
15 December 2011							
Min	1.07	2.25	6.39	4.39	4.07	0.00	1.42
Max	12.44	8.11	17.27	10.40	14.55	0.00	11.42
Ave	6.01	5.80	13.32	6.28	8.12	0.00	5.41
16 December 2011							
Min	1.30	1.10	1.93	1.29	0.23	0.00	1.33
Max	13.08	11.57	9.05	12.20	5.50	0.00	10.21
Ave	7.78	5.47	5.08	6.53	3.19	0.00	6.49
17 December 2011							
Min	1.21	4.13	0.33	1.98	1.40	0.00	1.88
Max	13.63	12.71	12.04	10.08	11.80	0.00	10.63
Ave	7.97	8.23	6.65	6.54	5.87	0.00	6.77
18 December 2011							
Min	1.30	3.08	0.60	1.26	3.28	0.00	1.32
Max	14.67	15.02	10.89	14.40	12.28	0.00	13.24
Ave	7.50	8.96	5.18	7.99	8.05	0.00	5.90

Table 30: Wind speed data for December 2011 week 4

	WM03	WM04	WM05	WM07	WM08	WM09	WM10
19 December 2011							
Min	3.04	0.56	5.99	4.10	0.40	0.00	1.98
Max	13.76	13.78	14.66	13.58	16.59	0.00	14.12
Ave	8.48	7.32	9.23	8.77	10.82	0.00	8.45
20 December 2011							
Min	1.07	0.74	2.88	1.51	0.23	0.00	0.51
Max	14.15	17.33	10.59	11.87	11.81	0.00	18.53
Ave	6.74	8.22	7.00	7.07	6.13	0.00	6.76
21 December 2011							
Min	1.77	1.38	2.70	1.38	3.04	0.00	0.66
Max	12.35	9.57	14.00	10.40	11.50	0.00	24.48
Ave	7.59	6.46	7.65	6.29	6.72	0.00	9.70
22 December 2011							
Min	3.41	0.73	2.40	0.37	4.16	0.00	0.71
Max	10.60	10.89	17.47	10.95	12.96	13.83	16.86
Ave	6.85	5.91	10.16	6.72	7.90	4.25	6.53
23 December 2011							
Min	1.82	2.24	2.08	3.49	3.40	3.34	3.95
Max	14.65	17.02	9.81	14.07	8.51	13.00	10.96
Ave	8.83	9.83	6.55	7.19	6.09	8.30	6.90
24 December 2011							
Min	0.85	2.79	6.87	1.51	4.19	1.92	5.17
Max	11.87	11.58	15.08	12.24	15.91	12.42	12.37
Ave	6.96	7.12	11.03	6.95	9.97	7.11	9.52
25 December 2011							
Min	0.66	0.98	10.60	1.67	5.02	1.93	0.27
Max	9.84	8.28	15.87	13.49	16.43	17.05	10.63
Ave	6.02	5.86	13.61	8.43	9.41	7.89	4.74

Table 31: Wind speed data for December 2011 week 5

	WM03	WM04	WM05	WM07	WM08	WM09	WM10
26 December 2011							
Min	1.56	1.00	1.98	2.54	0.77	1.57	0.76
Max	11.65	9.72	13.51	13.87	13.26	14.49	21.61
Ave	5.71	6.38	6.88	8.82	6.15	9.33	8.79
27 December 2011							
Min	1.23	0.36	1.51	2.17	4.59	1.45	0.67
Max	13.01	16.14	7.82	12.06	14.17	19.10	12.56
Ave	6.31	7.01	5.42	7.07	9.58	8.67	7.73
28 December 2011							
Min	0.47	2.70	3.83	2.06	0.23	3.28	1.15
Max	13.34	16.22	9.76	11.32	6.79	12.51	10.55
Ave	7.62	9.84	6.69	6.47	3.73	7.42	7.09
29 December 2011							
Min	0.98	5.33	4.03	1.42	0.86	3.88	0.71
Max	12.07	14.39	10.32	10.46	8.59	9.37	8.51
Ave	6.71	9.64	6.66	5.35	5.22	6.22	3.68
30 December 2011							
Min	0.99	6.53	1.02	1.30	0.23	1.53	1.01
Max	16.58	17.56	8.54	12.30	13.17	13.34	12.73
Ave	9.50	12.18	5.10	7.12	7.58	7.20	4.71
31 December 2011							
Min	1.05	4.89	2.02	1.38	0.23	3.32	1.46
Max	13.81	17.07	8.62	12.28	7.32	11.92	9.28
Ave	8.41	10.55	4.70	6.82	4.50	7.59	5.30

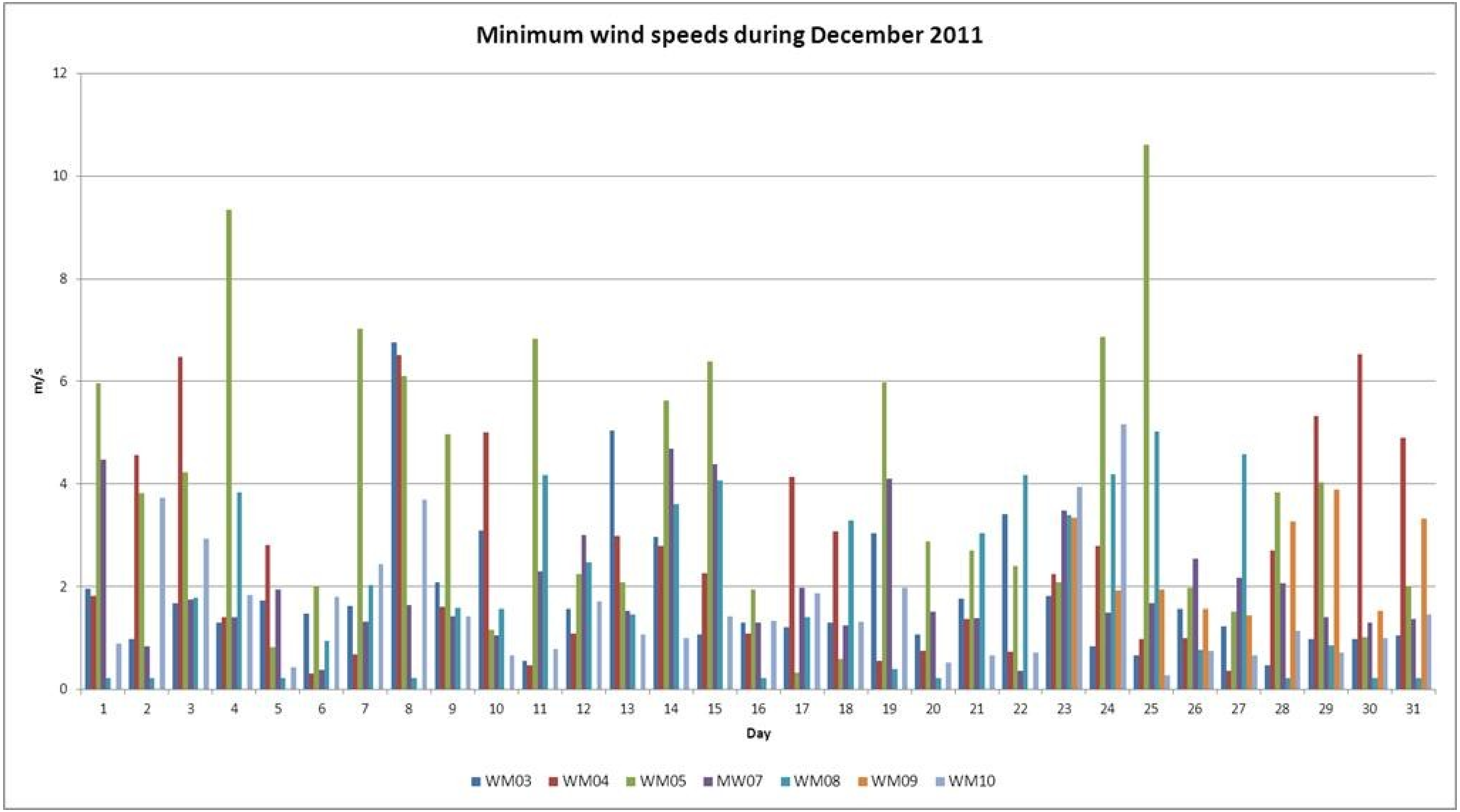

Figure 35: Minimum wind speeds for the seven wind measuring stations during December 2011

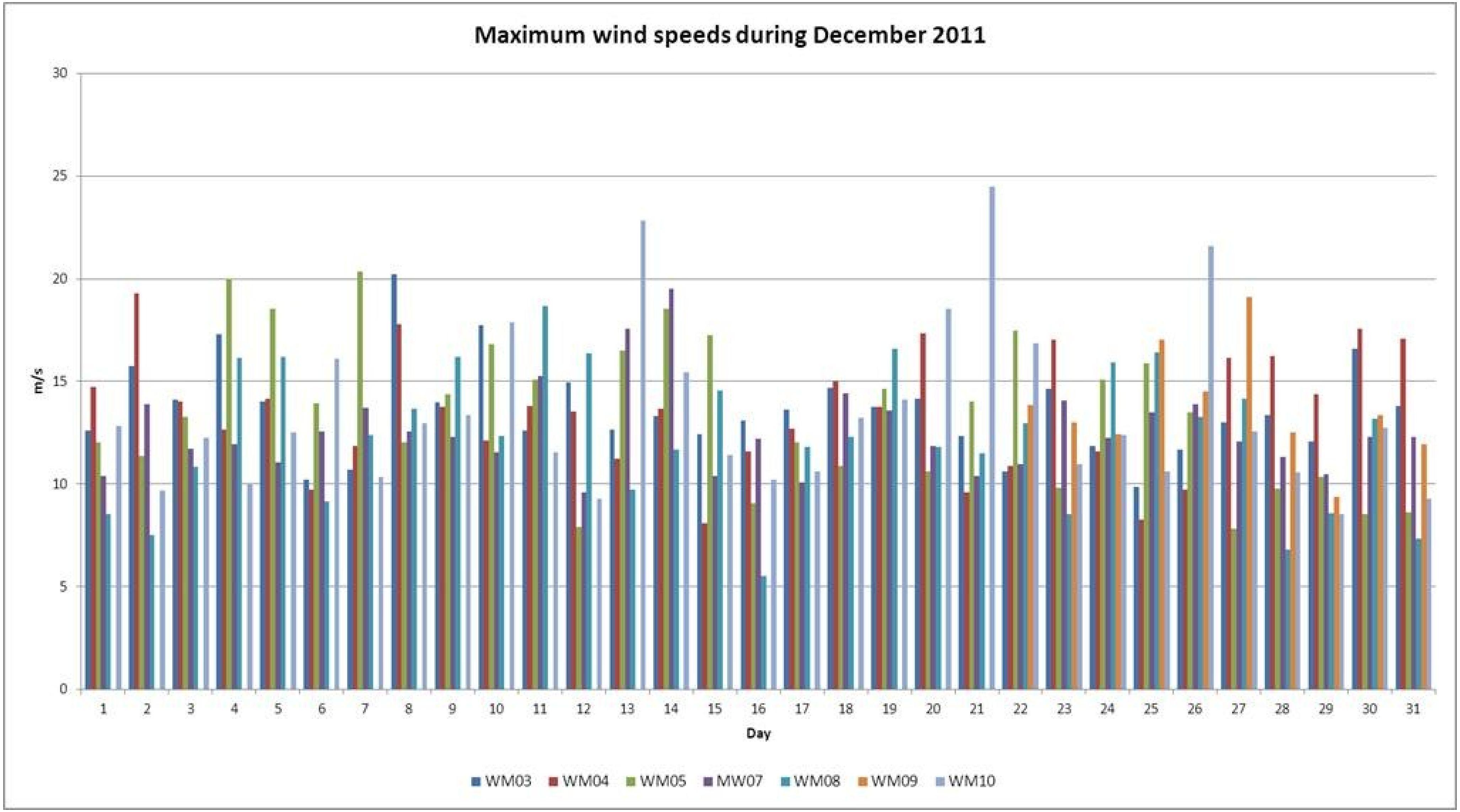

Figure 36: Maximum wind speeds for the seven wind measuring stations during December 2011

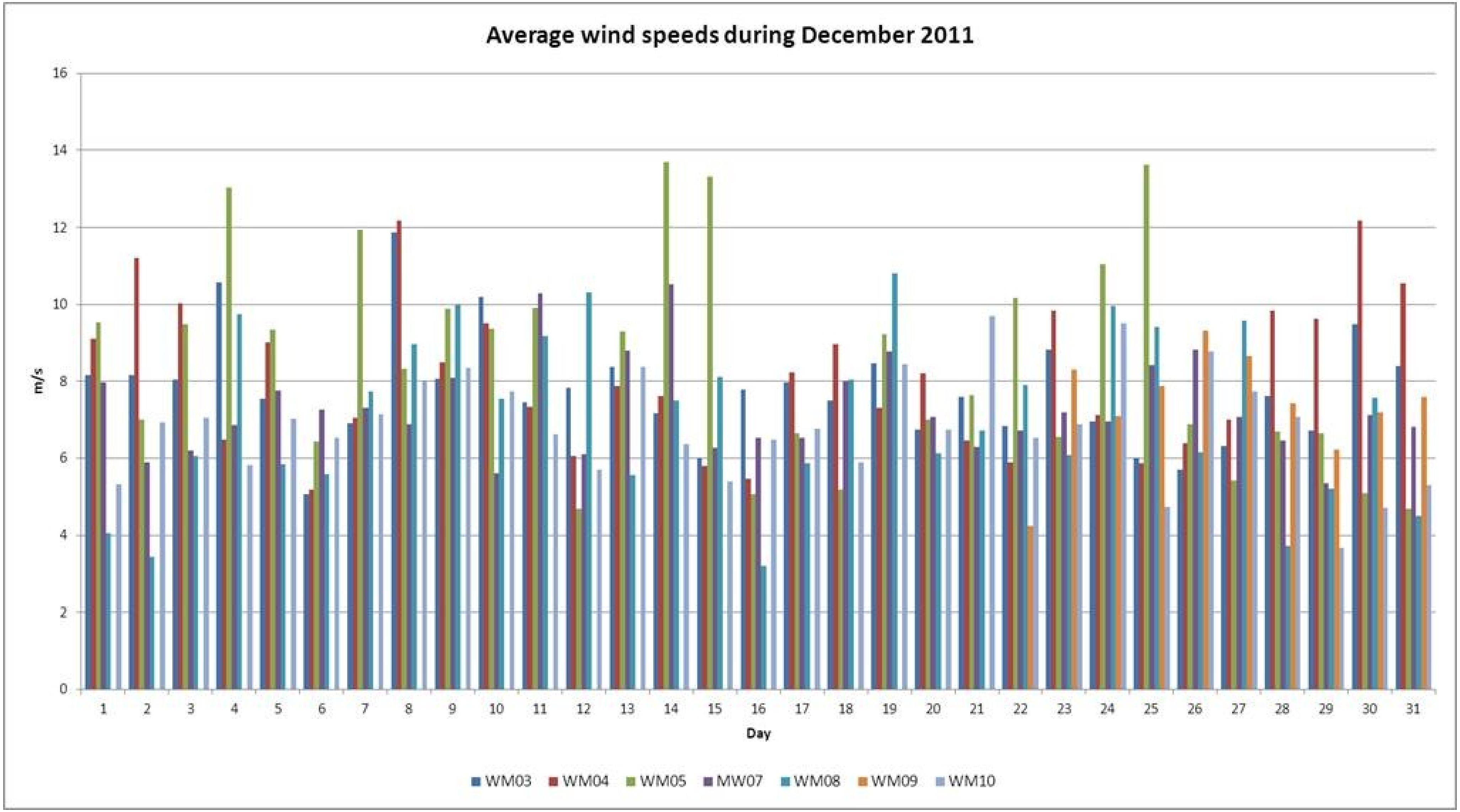

Figure 37: Average wind speeds for the seven wind measuring stations during December 2011

Wind speed data for July 2012

Table 32: Wind speed data for July 2012 week 1

	WM03	WM04	WM05	WM07	WM08	WM09	WM10
01 July 2012							
Min	2.26	0.30	6.09	1.47	0.23	7.99	0.00
Max	10.43	6.24	13.50	8.78	9.33	18.64	0.00
Ave	5.79	3.14	9.60	4.92	4.66	12.41	0.00
02 July 2012							
Min	1.43	1.73	0.37	0.73	0.23	1.00	0.00
Max	8.19	5.73	12.57	8.82	11.21	10.83	0.00
Ave	4.49	3.81	5.69	4.51	7.89	6.83	0.00
03 July 2012							
Min	2.69	0.33	2.75	1.39	0.23	3.84	0.00
Max	8.29	8.94	18.67	9.78	11.57	15.13	0.00
Ave	5.49	3.12	6.77	5.61	5.25	11.05	0.00
04 July 2012							
Min	2.93	1.63	1.10	3.67	4.24	1.15	0.00
Max	13.88	13.57	21.42	13.89	25.02	21.07	0.00
Ave	6.99	7.02	10.11	8.19	12.12	11.37	0.00
05 July 2012							
Min	2.60	1.15	1.16	1.85	0.91	2.22	0.00
Max	9.14	5.87	6.17	11.84	10.69	13.48	0.00
Ave	6.31	2.97	3.77	5.71	5.43	8.85	0.00
06 July 2012							
Min	1.26	1.60	3.10	0.64	0.23	7.68	0.00
Max	9.21	12.00	10.43	10.79	8.46	17.30	0.00
Ave	4.16	7.01	6.58	5.43	5.04	12.55	0.00
07 July 2012							
Min	0.90	1.05	2.01	2.21	0.55	0.86	0.00
Max	9.63	9.59	13.41	10.66	16.83	17.41	0.00
Ave	4.92	4.10	8.63	6.76	10.33	8.50	0.00

Table 33: Wind speed data for July 2012 week 2

	WM03	WM04	WM05	WM07	WM08	WM09	WM10
08 July 2012							
Min	2.03	2.48	9.93	6.24	7.65	3.04	0.00
Max	7.75	10.99	18.70	14.92	21.41	12.21	0.00
Ave	4.76	7.00	14.24	10.90	13.63	6.41	0.00
09 July 2012							
Min	1.14	1.41	10.00	5.47	5.48	6.42	0.00
Max	7.20	9.42	20.94	11.96	13.04	16.73	0.00
Ave	4.27	5.71	14.20	9.05	8.94	11.52	0.00
10 July 2012							
Min	0.83	1.55	10.12	6.23	3.99	8.70	0.00
Max	7.82	6.29	18.87	10.14	10.91	15.94	0.00
Ave	4.39	4.75	13.64	7.98	7.79	12.55	0.00
11 July 2012							
Min	0.85	3.76	3.88	2.29	7.14	2.45	1.40
Max	13.34	11.76	12.14	11.95	17.17	12.61	11.89
Ave	6.35	8.07	8.77	6.76	11.24	8.79	6.85
12 July 2012							
Min	4.42	1.54	3.04	0.26	4.25	1.86	0.27
Max	13.28	11.99	12.95	9.22	11.13	7.32	7.67
Ave	9.08	8.35	5.98	3.46	8.13	4.67	3.33
13 July 2012							
Min	2.79	6.37	2.39	4.34	0.30	4.25	1.06
Max	13.23	13.43	15.85	14.56	7.91	9.50	9.01
Ave	7.79	10.22	9.26	9.55	4.38	7.53	4.07
14 July 2012							
Min	4.46	5.68	2.92	6.54	0.68	0.00	0.71
Max	12.61	15.19	14.26	15.69	22.48	0.00	17.36
Ave	9.07	10.78	9.15	11.61	11.81	0.00	9.01

Table 34: Wind speed data for July 2012 week 3

	WM03	WM04	WM05	WM07	WM08	WM09	WM10
15 July 2012							
Min	0.98	0.38	5.46	4.80	9.14	6.06	9.39
Max	9.51	8.68	14.62	14.89	23.32	11.04	24.11
Ave	4.51	3.59	9.78	10.25	14.71	8.29	15.04
16 July 2012							
Min	2.48	0.95	3.11	1.08	8.13	2.29	8.18
Max	11.56	7.37	9.42	10.32	15.56	12.17	14.21
Ave	5.74	3.89	6.42	5.27	11.37	6.25	11.47
17 July 2012							
Min	3.28	1.25	0.59	0.59	1.51	4.21	1.69
Max	11.67	8.38	10.32	7.52	12.48	8.54	13.62
Ave	7.95	4.34	6.03	3.27	6.47	6.30	7.73
18 July 2012							
Min	2.27	2.85	0.21	0.66	0.23	3.43	2.64
Max	12.91	9.28	9.33	6.84	12.83	11.35	11.46
Ave	8.76	5.21	2.96	3.82	6.02	6.87	6.90
19 July 2012							
Min	4.86	2.56	0.65	4.71	0.23	7.08	3.27
Max	16.16	12.73	12.04	13.17	13.27	15.32	12.54
Ave	8.39	7.02	3.98	9.63	6.06	10.81	8.65
20 July 2012							
Min	4.79	4.63	3.59	4.95	3.87	8.53	5.24
Max	13.55	12.53	19.36	13.75	16.47	18.04	20.38
Ave	7.88	9.89	10.52	8.27	7.47	12.64	10.86
21 July 2012							
Min	2.70	3.97	2.18	1.08	0.23	6.26	0.72
Max	15.81	15.26	25.01	13.68	16.12	17.02	8.25
Ave	8.52	9.56	12.09	8.72	6.59	11.91	3.90

Table 35: Wind speed data for July 2012 week 4

	WM03	WM04	WM05	WM07	WM08	WM09	WM10
22 July 2012							
Min	1.10	0.46	3.44	0.31	8.43	2.28	2.71
Max	9.41	8.02	15.15	12.07	19.80	12.85	13.78
Ave	4.93	3.74	7.94	7.43	13.78	7.84	9.34
23 July 2012							
Min	1.75	1.16	1.03	0.33	0.74	0.95	0.54
Max	8.54	5.16	5.99	6.30	10.89	9.31	10.93
Ave	5.50	2.77	3.09	3.38	4.67	3.76	5.21
24 July 2012							
Min	0.28	0.69	2.31	2.83	1.68	3.29	1.22
Max	7.96	6.52	14.39	7.39	9.83	8.48	9.38
Ave	3.83	3.38	8.08	5.30	5.65	5.51	5.43
25 July 2012							
Min	1.37	1.03	0.21	0.44	0.23	3.12	2.18
Max	11.07	9.86	5.79	9.79	7.36	13.97	9.69
Ave	6.46	4.13	2.69	3.91	2.47	8.29	5.17
26 July 2012							
Min	2.01	1.31	1.06	5.61	0.23	10.26	6.23
Max	11.91	8.98	15.51	17.22	17.01	20.25	13.76
Ave	6.82	5.30	7.09	9.75	7.01	14.15	9.58
27 July 2012							
Min	3.75	2.46	1.93	2.39	2.10	4.13	6.24
Max	10.90	10.35	11.08	11.90	18.34	19.25	17.86
Ave	7.19	6.86	5.99	5.71	10.38	7.94	10.90
28 July 2012							
Min	3.62	2.18	2.17	0.44	0.94	5.36	3.45
Max	12.57	10.74	10.03	9.59	10.37	10.07	12.13
Ave	8.48	4.94	5.90	4.15	4.97	7.57	7.59

Table 36: Wind speed data for July 2012 week 5

	WM03	WM04	WM05	WM07	WM08	WM09	WM10
29 July 2012							
Min	5.66	1.81	8.14	1.32	1.01	1.50	1.43
Max	12.89	7.31	14.28	10.00	10.11	8.26	11.99
Ave	9.88	4.31	10.90	4.91	5.49	3.51	7.24
30 July 2012							
Min	2.43	0.73	1.68	1.17	0.36	2.42	0.51
Max	11.30	8.27	13.72	9.20	11.10	11.85	11.64
Ave	7.95	3.83	6.67	4.80	4.90	8.63	4.78
31 July 2012							
Min	1.48	1.42	6.73	5.69	1.66	5.81	2.11
Max	15.59	13.68	18.88	14.16	19.06	20.16	13.17
Ave	7.60	7.33	12.25	9.20	10.85	11.25	8.85

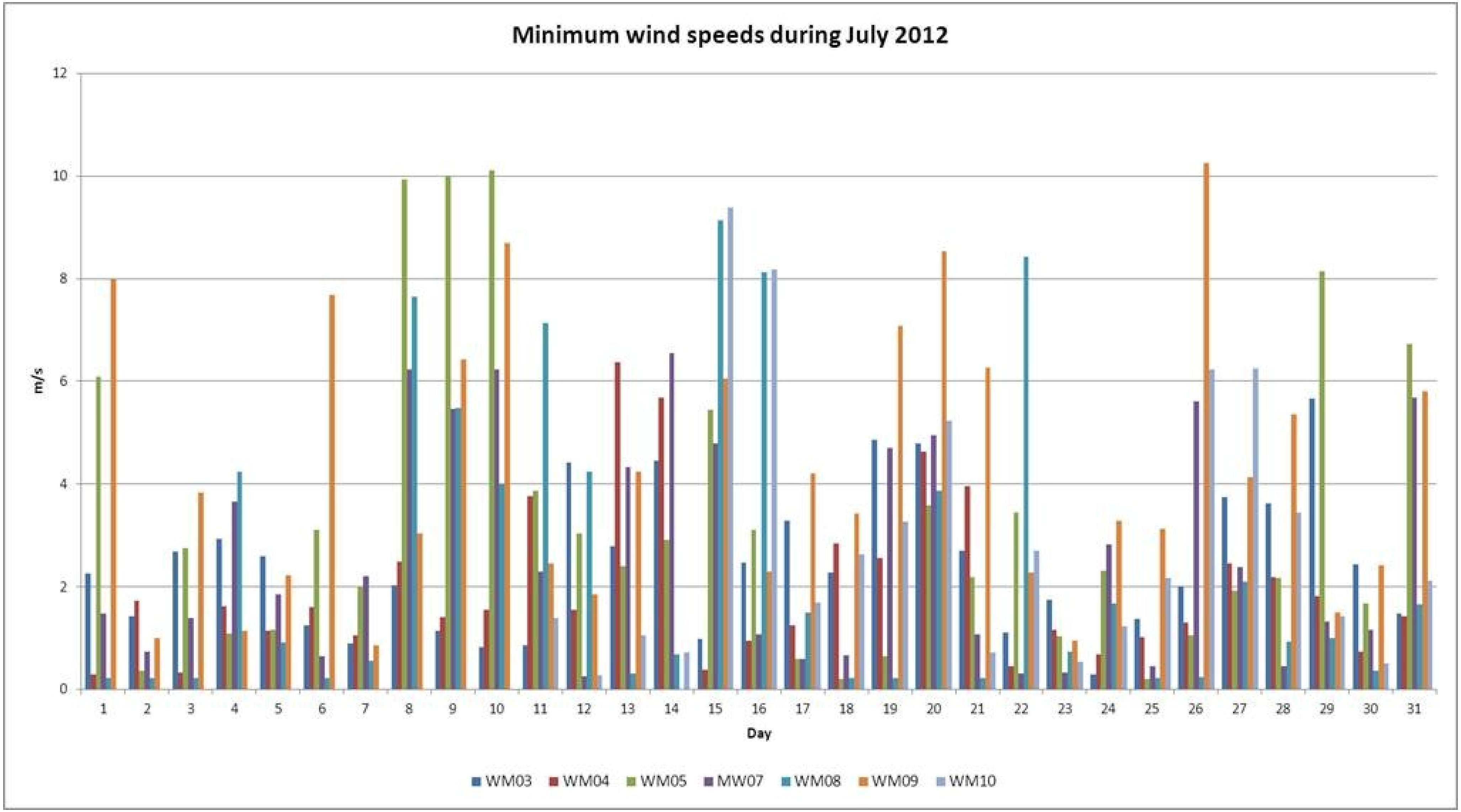

Figure 38: Minimum wind speeds for the seven wind measuring stations during July 2012

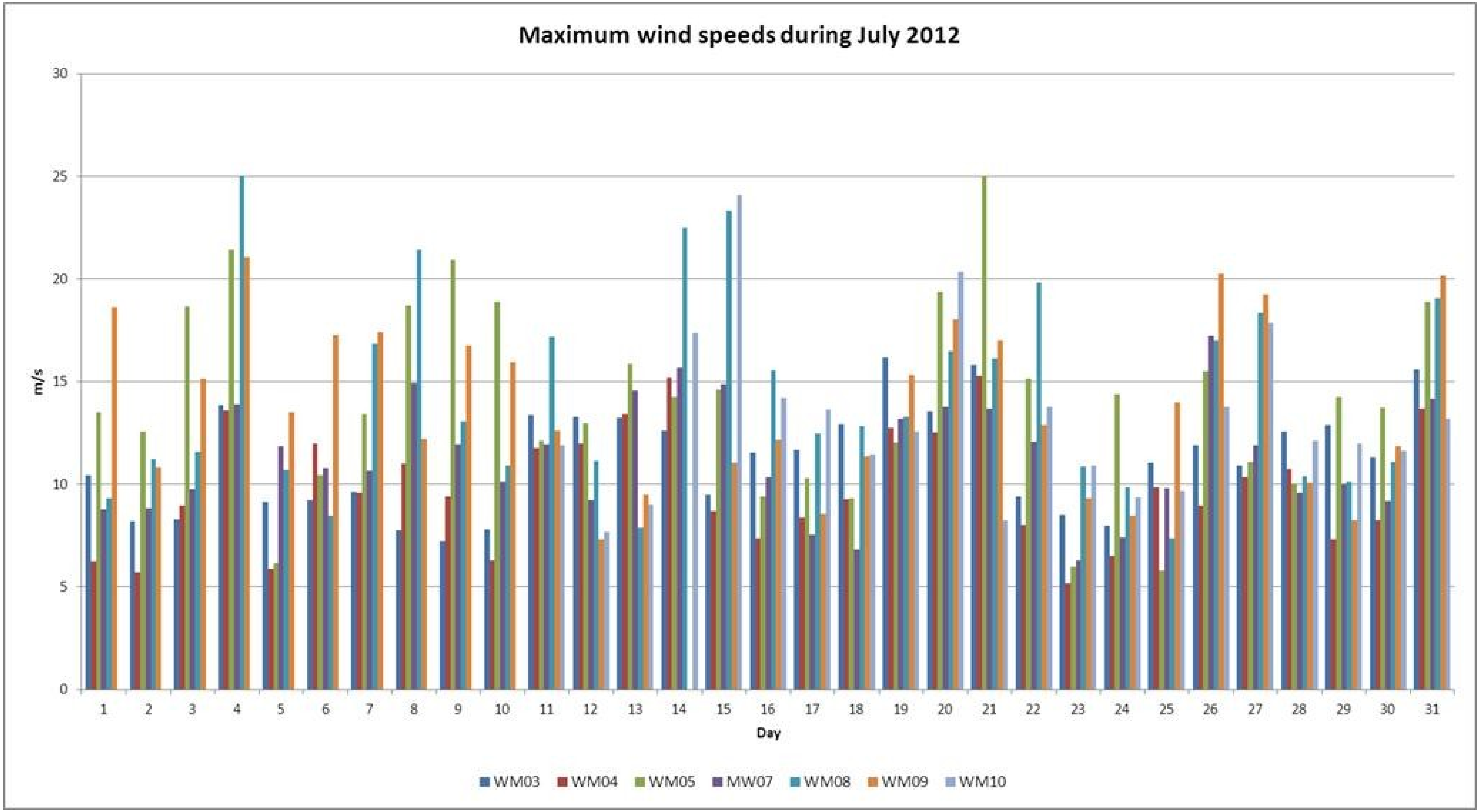

Figure 39: Maximum wind speeds for the seven wind measuring stations during July 2012

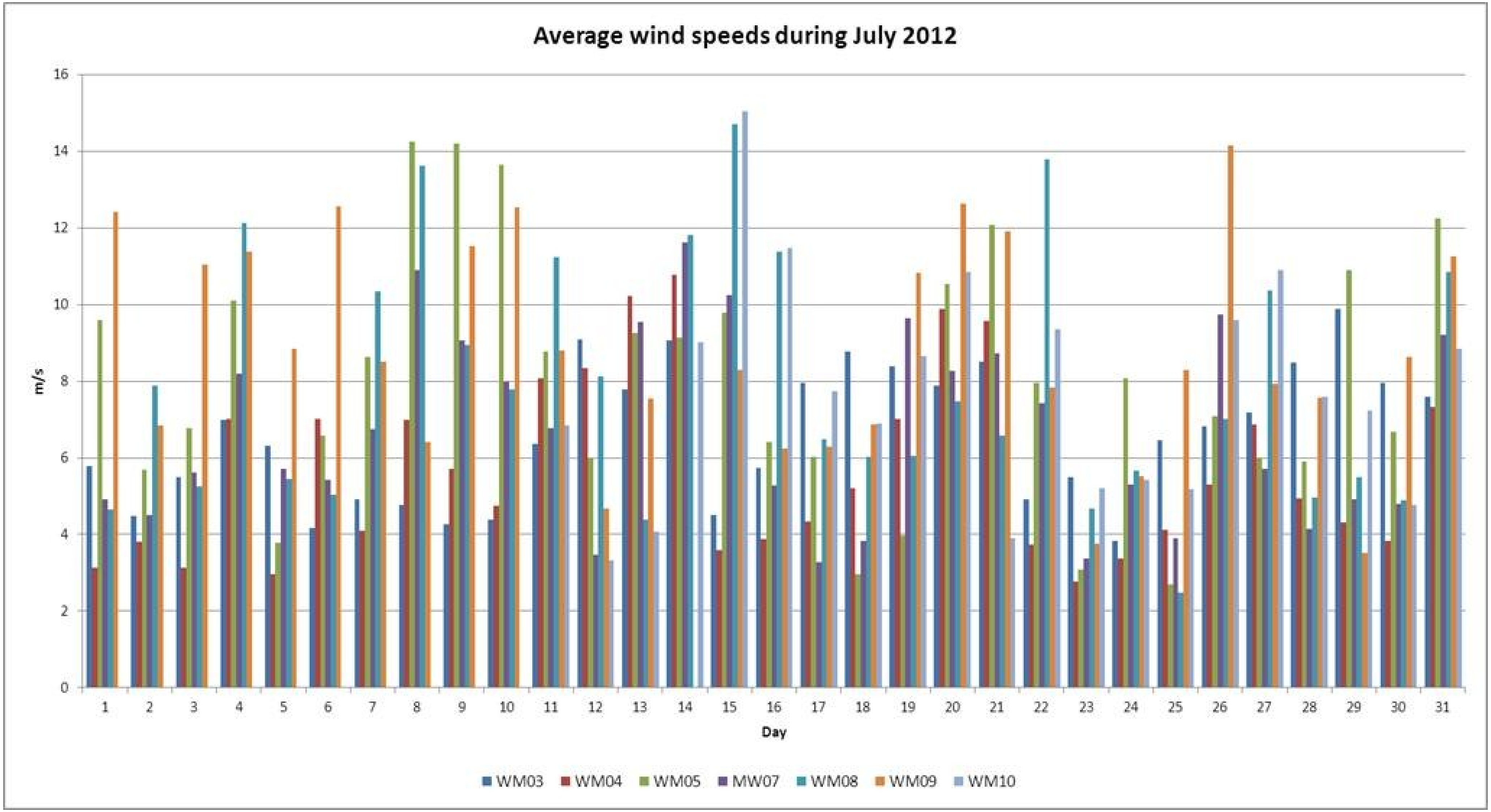

Figure 40: Average wind speeds for the seven wind measuring stations during July 2012