INTEGRATED AND SYNCHRONISED APPROACH TO DSM INITIATIVES

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Disclaimer

The contents of this research report are the views and opinions of the author and not necessarily that of Eskom.

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ABSTRACT

Demand side management (DSM) interventions aim to influence the way electricity is used by customers through specific actions and programmes. A desired load shape is achieved by encouraging electricity users to consume more electricity at times when excess capacity is available and less during times of constraints. In South Africa, load management is a fixed response between 18:00 and 20:00 and includes load shifting and load curtailment out of the Time of Use (TOU) tariff peak period. Demand Market Participation (DMP), on the other hand, is a more flexible curtailment initiative and is scheduled day ahead only if constraints are expected.

This study evaluates the effectiveness of load management and DMP initiatives and proposes an optimised approach. Customer responses to the TOU tariff and the alignment of system and tariff peaks were investigated by making use of TOU metering and system sent out data. The research shows that not all customers respond to the TOU tariff signal. System peaks and TOU tariff peaks are aligned however a number of system peaks occur out of the tariff peak periods. The research further shows that load management and DMP initiatives shift and curtail load effectively. Load management initiatives with an energy efficient component are very effective and highlight the importance of energy efficiency as a whole.

Historical system sent out data was analysed and the results show that a significant number of load management initiatives can become more dynamic. It was further evident that curtailment initiatives contribute more to the system than load shifting initiatives. Load management initiatives are initiated by TOU tariff peaks and not system peaks. Load management initiatives could therefore be optimised if system constraints are used as a reference and not TOU periods. It was also evident that load shifting initiatives do not add much value during the low-demand seasons. The results of this study could be utilised to improve DSM initiatives. This study also serves to influence future DSM strategies which will embrace a sustainable DSM programme.

LIST OF ACRONYMS

ADMD	After Diversity Maximum Demand
BMS	Building Management System
CG	Customer Group
CUE	Cost of unserved energy
DME	Department of Minerals and Energy
DMP	Demand Market Participation
DPE	Department of Public Enterprises
DR	Demand Response
DSM	Demand Side Management
DST	Daylight saving time
EE	Energy Efficiency
EEDSM	Energy Efficiency and Demand Side Management
EPRI	Electric Power Research Institute
ESI	Electricity Supply Industry
ESCo	Energy Services Company
GSM	Global System for Mobile Communications
HWC	Hot Water Cylinder (also referred to as a geyser)
Hz	Hertz
IEEE	Institute of Electrical and Electronics Engineers
IRP	Integrated Resource Planning
ISO	Independent System Operator
kW	Kilowatt (demand)
LRMC	Long Run Marginal Cost
LSE	Load Serving Entity
MD	Maximum Demand
M&V	Measurement and Verification
MW	Megawatt (demand)
MWh	Megawatt hour (Energy)
NERSA	National Energy Regulator of South Africa
PCP	Power Conservation Programme
PLC	Programmable Logic Controller
RCR	Radio/audio Ripple Control Receiver
RTO	Regional Transmission Organization
SCADA	Supervisory Control and Data Acquisition
T&D	Transmission and Distribution
TOU	Time of Use
VOLL	Value of Lost Load

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CHAPTER 1: INTRODUCTION

1.1 Introduction

The South African economy has experienced a healthy growth period since the 1990s. This has been reflected in the national electricity demand growth. Industrial consumption has increased with the rise in commodity prices. A massive electrification programme was initiated by the South African government and Eskom through the South African electrification programme.

The proportion of the population with access to electricity has increased from 33.3% to nearly 70% at the end of 1996 [1], [2]. Since 1996, an additional 450 000 residential houses have been electrified per annum [2]. The residential sector is responsible for approximately 17% of the electricity consumed in South Africa. This sector is also responsible for 35% of the maximum demand (MD) [2].

"The electrification programme has resulted in a significant increase in peak demand with profound implications for the future generation plant mix" [3]. Eskom's plant availability increased in the early 1990s, but has declined in recent years [1]. As a result of the growth in demand, Eskom is faced with a fast diminishing reserve margin across the load profile.

The current installed capacity is insufficient to maintain a safe reserve margin to meet future forecasted peak demand [4]. The power system is operated close to capacity and this could result in widespread blackouts. The reserve margin does not necessarily translate into an ability to meet demand, but represents the additional available supply capacity, able to respond to unexpected system events.

There are different methodologies to determine the reserve margin. The reserve margin is generally calculated by dividing the capacity with the highest demand in one hour for the year. In theory, most calculations include firm capacity (supply and demand) that contributes to meeting demand. A resource that is able to meet demand for all hours in a year can be counted in full. A resource that can only meet the demand for some hours of the year cannot be counted in full.

Not all utilities use the same criterion to establish the reserve margin. Each utility's specific methodology to establish the reserve margin is based on a matter of study and definition. Internationally, the safe reserve margin requirement ranges between 15% and 20% [5], [6].

Figure 1-1 shows the growth in generation capacity compared with peak demand on the integrated Eskom system and the percentage reserve margin from 1950 to 2002. The sustained growth in new generation capacity between 1974 and 1993 is evident. The reserve margin peaking at 38% in 1993 is also evident [1]. According to Figure 1-1, the reserve margin dropped to 20% in 2002. Eskom's current published reserve margin is 8% [7]. As new record consumption figures are recorded, this reserve margin will reduce in the future.

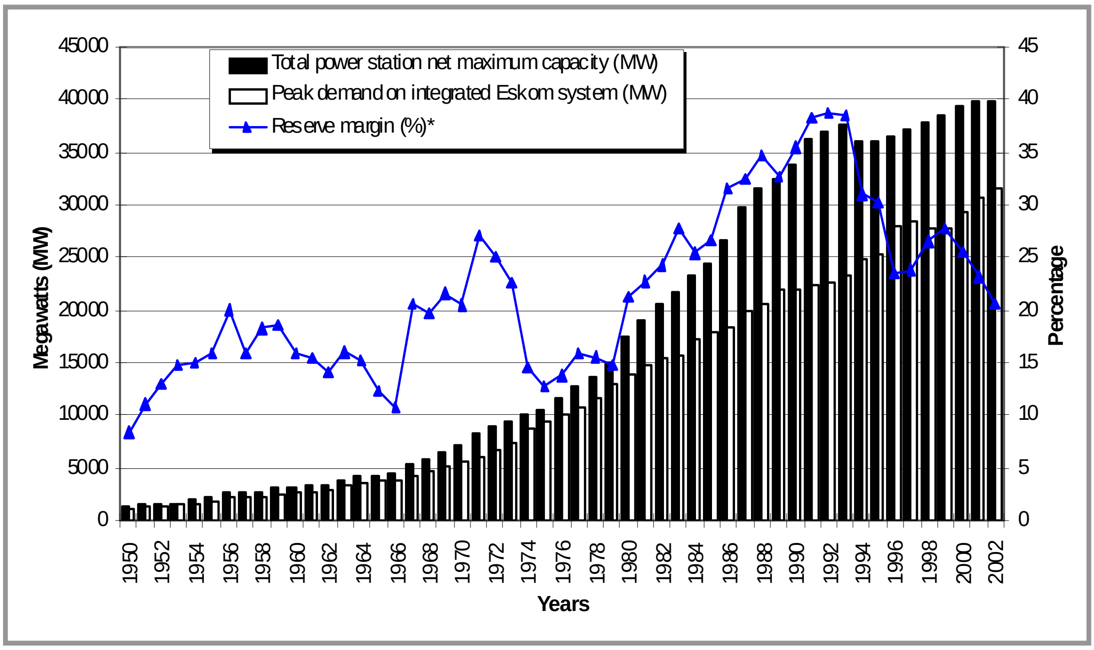

Figure 1-1: Net maximum capacity, peak demand and reserve margin (1950 to 2002) [1]

Growth in electricity demand is a sign of a growing economy and is viewed positively internationally. However, electricity outages and shortages could affect continued economic growth and reduced local and foreign direct investment in the South African economy [8]. It is, therefore, very important to ensure a reliable and efficient electricity sector. Eskom is investing in new generation, transmission and distribution infrastructure to meet the demand for electricity. Eskom is also implementing methods to balance supply and demand through a demand side management (DSM) programme.

Investment decisions in the power sector involve high risks. New generation capacity is capital intensive and poor investment decisions could mean that power needs are not met. Poor decisions could also result in unnecessary excess capacity, which is very costly to the economy [1]. DSM mechanisms should, therefore, be included in future system planning.

Figure 1-2 was drafted using sent out data. This figure indicates the growth in consumption for each year from 2000 to 2006. The consumption has been sorted from the highest consumption in any hour to the lowest consumption in any hour for each year (from 2000 to 2006). By analysing this graph, it is clear that both the base load and peak load periods have increased steadily over the past six years. This indicates that consumption has increased steadily since 1999 and is continuing to increase. This figure also illustrates why more expensive generation must be used for more hours each year to meet the demand for electricity. Therefore, as the purchasing costs of electricity increases, so the popularity of DSM offerings in the electricity industry also increases.

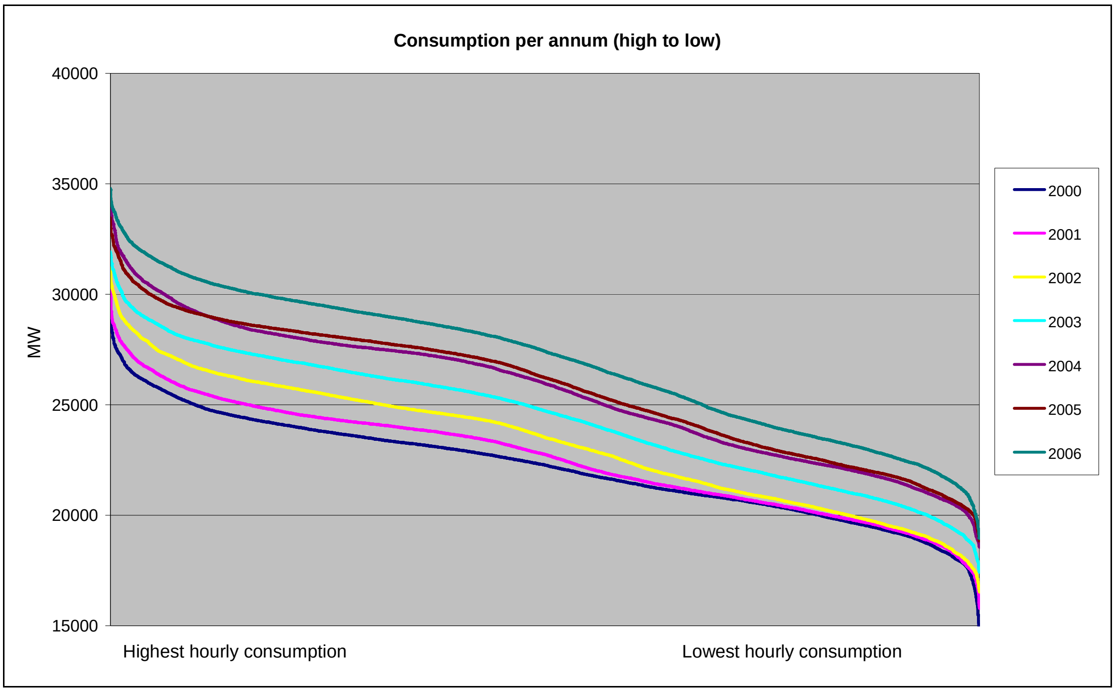

Figure 1-2: Consumption sorted from highest to lowest consumption per annum

Figure 1-3 reflects the time frame for new capacity. This outlook includes the expected capacity expansions that are required until 2024. It also indicates the estimated impact of DSM. Eskom will have to implement an aggressive DSM plan along with its other supply side options to ensure that the future supply meets the demand [9]. The DSM plan will also have to assist in ensuring a sufficient reserve margin for system security and reliability [10].

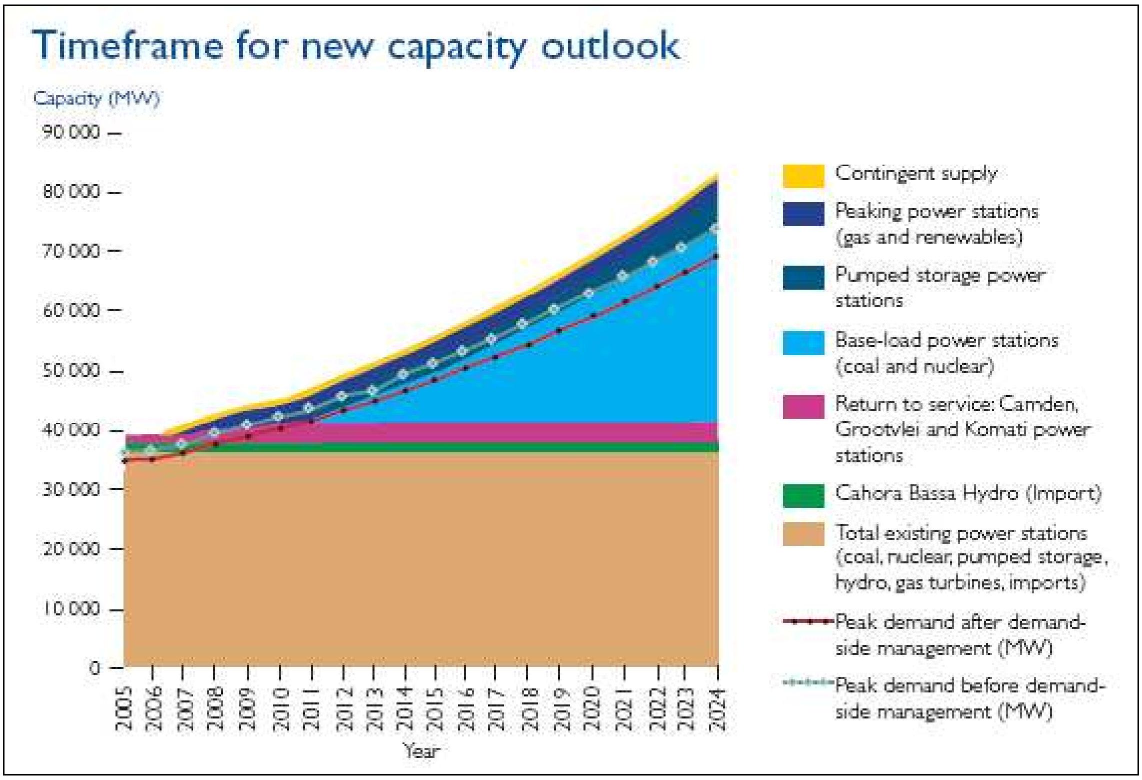

Figure 1-3: Time frame for new capacity outlook [7]

*Eskom announced in December 2008 that it will not proceed with construction of a second nuclear power plant. New base-load power stations is expected to be coal fired until further notice.

It was estimated that Eskom will run out of peaking capacity by the year 2007 [4]. Eskom needs to invest billions of rands in new power stations, other infrastructure, energy efficiency and programmes to reduce energy utilisation at certain time periods. Because of the expected shortage in peaking capacity, the National Energy Regulator of South Africa (NERSA) mandated Eskom to implement a programme according to the Regulatory Policy on Energy Efficiency and Demand Side Management (EEDSM Policy) [4]. Table 1-1 indicates the annual displacement/reduction targets per sector according to the EEDSM policy.

Table 1-1: Categories of EEDSM and annual targets [4]

Programme category	**Annual displacements (MW)**
Residential energy efficiency	32
Commercial energy efficiency	14
Industrial and mining efficiency	16
Residential load management	49
Industrial and mining load management	41
Annual total	152

The EEDSM Policy also provides guidelines for matters concerning funding, the administration of funds, asset ownership and the development of DSM plans. The implementation of DSM programmes by energy services companies (ESCos) and the requirement to create an awareness of DSM with customers are also covered.

The NERSA requirement of 152 MW per annum results in an internal DSM long-term target of 4 225MW over a 20-year period. This is more than the output of a new six-unit (approximately 600MW per unit) power station [11]. Eskom initially committed itself to the target of 152MW per annum.

However, in view of the current capacity shortages, Eskom is aiming to achieve a very ambitious saving of 3 000MW over the next five years (2007 to 2012) [11]. A DSM target is also expected to be set over the medium to long term (2012 to 2025). The intention is to alleviate supply constraints and to displace the need for the more costly supply side options that are currently under consideration.

Figure 1-4 reflects a typical winter weekday load profile and the expected load profile in 2012 with and without DSM interventions. With the current growth in demand, DSM initiatives can effectively defer new capacity.

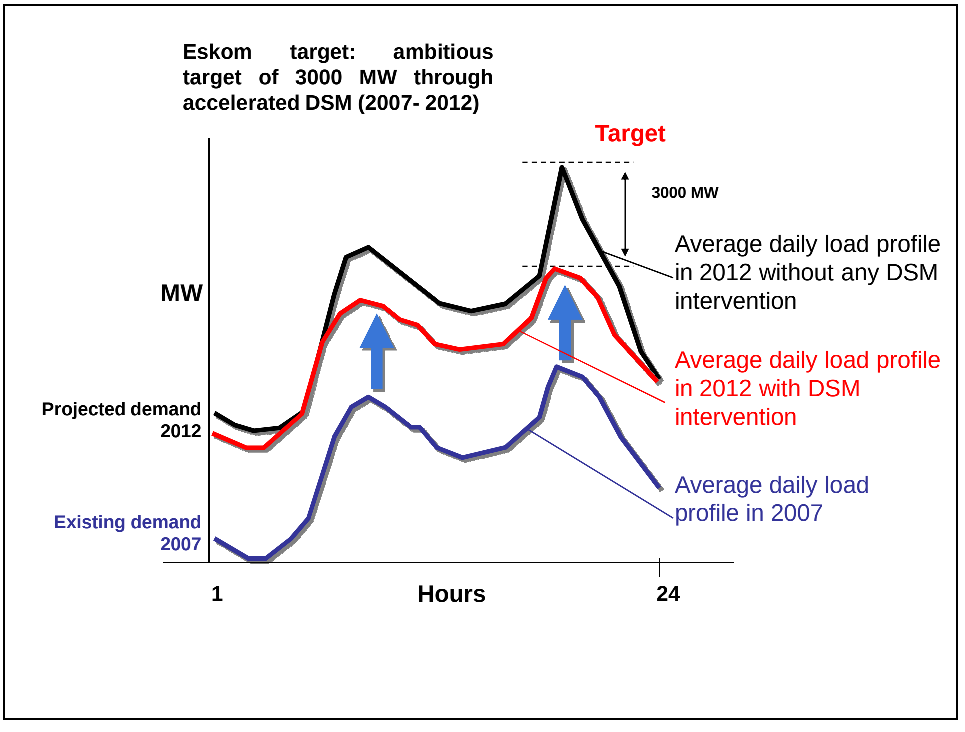

Figure 1-4: Expected winter weekday demand profile 2007 to 2012 [9]

1.2 Background on Eskom DSM initiatives

Due to the adverse economic impact of outages, Eskom uses various types of reserves to manage daily supply shortages in order to avoid load-shedding as far as possible. The Eskom DSM programme contributes to these reserves. Eskom DSM incorporates the following:

- energy efficiency;
- strategic energy conservation;
- de-marketing to alternative energy sources and supply side options;
- load management; and
- load curtailment through DMP.

Different funding and incentive mechanisms apply for the abovementioned DSM initiatives. Eskom funds load management and energy efficiency programmes through a fund that was established by the Department of Minerals and Energy (DME) and NERSA. Projects are evaluated technically and financially according to criteria.

The contribution of energy efficiency and the reduction of the overall demand profile is crucial. The load profile can only be reduced by implementing effective energy efficient initiatives. Due to the fact that energy efficient initiatives can not be dispatched on request as is the case with load management and DMP initiatives, this dissertation will mainly focus on load management and DMP initiatives. Curtailment initiatives with an energy efficient component will also be investigated and discussed.

1.3 Load management

Load management is a programme that consists of load shifting and load curtailment initiatives. Load is shifted/curtailed out of peak times as defined by the TOU (Megaflex, Miniflex and Ruraflex) tariff. ESCos are private companies that help to achieve DSM goals. ESCos approach possible clients and carry out energy audits to establish if a load management project is feasible.

If a project is feasible and the customer supports the initiative, the ESCo submits a project proposal to Eskom. Eskom evaluates each project according to the criterion set by NERSA. International experience has shown that it is imperative to have strong private sector participation in the form of ESCos for the effective delivery of DSM programmes [2].

After evaluation, viable projects are implemented once an independent measurement and verification (M&V) entity has confirmed the baseline. After an ESCo has implemented the project, the independent M&V entity verifies the load shift/curtailment. The customer must then maintain the load shift/curtailment for a period of five years. The independent M&V reports provide an impartial, credible and transparent process. The M&V reports further quantify and assess the impact and sustainability of load management projects and the results of the DSM initiatives are reported to NERSA [2].

The contracted savings is mostly an annual average and not a fixed daily or monthly quantity. However, this can vary according to what was initially proposed by the ESCo and accepted by Eskom and the customer.

The incentive for customers to take part in load management projects is financial. This incentive is achieved through a retail tariff signal. The Eskom time of use (TOU) tariff reflects the variation in energy rates for different times of each day, as well as the high-demand and low-demand seasons. The TOU tariff sends signals to customers on the changes in costs associated with the long run marginal cost (LRMC) of electricity.

TOU tariffs are intended to establish a high electricity price when the demand is high (high demand is generally associated with high generation costs). A further intention is to establish a low electricity price when the demand is low. Figure 1-5 highlights the times of the day that have high-demand characteristics, as defined by the Eskom TOU tariffs. This figure further represents the applicable tariffs for the time of day.

Daily peaks that occur in the morning and afternoon on the aggregated utility load are referred to as system peaks. The Eskom TOU tariff structure assumes that system peaks co-incise with the tariff peak. The Eskom tariff peak times are between 07:00 and 10:00 in the mornings and between 18:00 and 20:00 in the evening during weekdays.

Figure 1-6 represents a typical winter load profile with high-demand characteristics. Peak prices in the high-demand season are approximately three and a half times higher [12] than peak prices in the low-demand season (Table 1-2). Future load shift/curtailment initiatives rely on effective tariff structures.

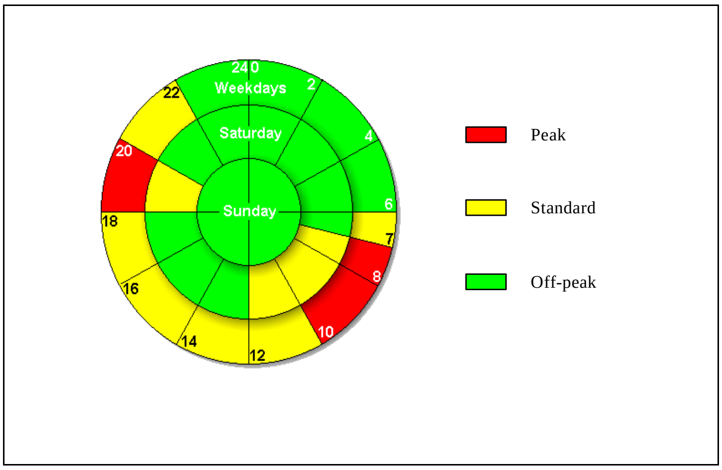

Figure 1-5: The Eskom TOU tariff structure (different rates for specific times of each day) [12]

Table 1-2: EskomTOU megaflex tariffs (1 July 2008 to 31 March 2009) [12]

High-demand season (June to August)		Low-demand season (September to May)
84.60 c/kWh	Peak	24.01c/kWh
22.37 c/kWh	Standard	14.90 c/kWh
12.16 c/kWh	Off-peak	10.56 c/kWh

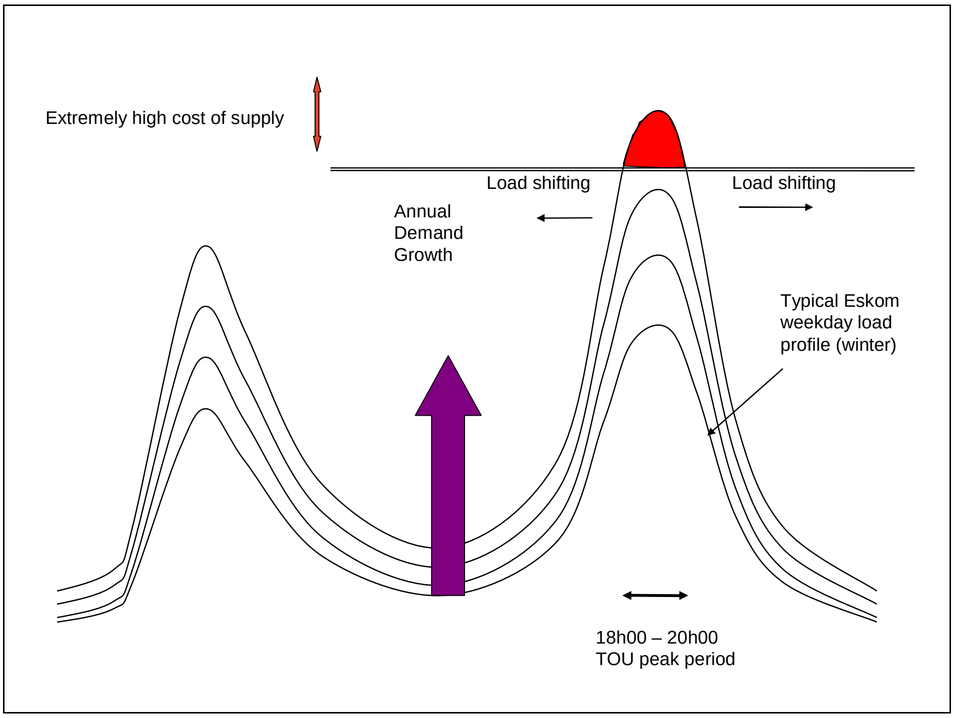

Figure 1-6: Typical winter load profile with high-demand characteristics at specific times

1.4 Demand market participation (DMP)

Due to the need for several types of reserves essential for the reliable operation of a power system, Eskom developed a load curtailment initiative in 2003 referred to as demand market participation (DMP). “DMP is a short-term pricing initiative that offers participating customers the opportunity to receive monetary compensation for load reductions during times of supply or network constraints.” [13] DMP is effective during constraints but it is possible that DMP can not be sustained in the long run due to its cost and willingness of customers to respond.

DMP was initially developed for large power users and an aggregator (combination of smaller customers) was introduced later. The minimum entry level for participation in the aggregator is 500kW to a maximum of 15MW [13]. In times of constraints, Eskom can request these customers to curtail load. DMP provides reserves that would normally have been provided by generators. DMP addresses supply and network constraints. It provides additional reserves and increases efficiencies in the electricity supply industry (ESI) by allowing customers to participate in the reserve market.

DMP customers are never asked to reduce load when Eskom has sufficient capacity to meet the demand. DMP is, therefore, a useful mechanism to supply reserves and to free up capacity for the energy market. Figure 1-7 illustrates an actual load curtailment event between 18:00 and 20:00 on a specific day.

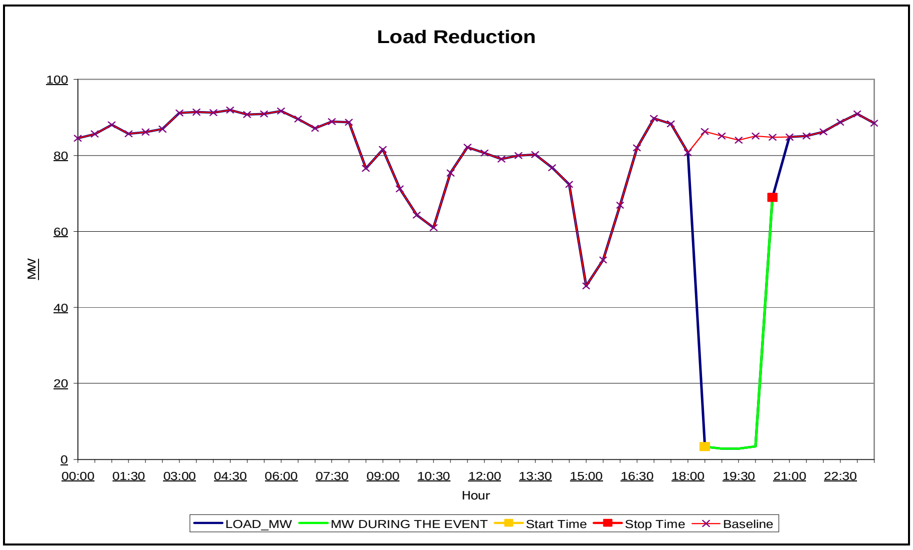

Figure 1-7: Example of DMP load curtailment

The financial benefits of DMP to the customer are through capacity and energy payments. A customer's cost to respond to DMP may include additional labour costs, paying overtime and added material and process costs [14]. An additional benefit of DMP is the reduced possibility of unexpected interruptions in supply.

Customers participating in the reserve market receive standby payments only. Standby payments range from R8/MW to R10/MW per hour [15]. Supplemental participants receive energy, as well as a standby payment. Energy payments can be as high as R800/MWh, depending on competition between participants [15]. Table 1-3 indicates the applicable DMP products that are currently available.

Table 1-3: Applicable DMP categories [16]

Category	**DMP specification**
Instantaneous reserves (Respond on low frequency)	Respond within 10 seconds Maintain response for up to 10 minutes Two events per day or more on a voluntary basis
10-minute reserves	Respond within 10 minutes from call Maintain response for up to two hours Maximum of three events per day 90% adherence up to 600 hours per annum
Supplemental reserves	Respond within 10 minutes to two hours Maintain response for up to two hours Maximum of one event per day 90% adherence up to 200 hours per annum
Emergency DMP	Respond within 10 to 60 minutes Maintain response for up to two hours Maximum of one event per day 90% adherence up to 40 hours

1.5 Power conservation programme

The Department of Public Enterprises (DPE) and Eskom published a document on 13 March 2008 that indicates that South Africa is entering its second power rationing phase [17]. This document calls on commercial, residential and other smaller customers to save 10% of their consumption and to reduce demand. This media release indicated that a reduction of 3 000MW is necessary to perform the required maintenance.

If the required load reduction cannot be achieved, it could result in forced outages (load-shedding). Further developments regarding power rationing through the power conservation programme (PCP) have been mentioned. These developments must still be finalised and legislation might be required to enforce this. If legislation is required, enforcing the PCP programme will be delayed even further. More cost-reflective tariffs might resolve this issue more easily, but will have to be investigated.

1.6 Background to the research problem

In international electricity markets, electricity prices are market related and prices vary according to supply and demand [6], [14]. The financial incentive for customers to participate in DSM initiatives, therefore, varies hourly. Utilities generally achieve their desired load shape objective due to very high prices during times of constraints and low prices when excess capacity is available. In international markets DSM is also referred to as demand response (DR).

Eskom has initiatives to promote a desired load shape objective and this includes load shifting/curtailment). The two initiatives that will be discussed in this dissertation are known as load management and DMP. Load management consists of load shifting and load curtailment. With load shifting, load is shifted out of the TOU peak period to standard and off-peak periods. With load curtailment, load is curtailed out of the TOU peak period. The main difference between load shifting and curtailment is that load curtailed will not be required in any other period and is completely removed from the system. Participation in load management is motivated by a financial incentive due to the TOU tariff structure.

Load management is, therefore, not based on actual network requirements or constraints. It is possible that load management initiatives might shift load to periods when constraints are experienced. It is further possible that the system peaks and the TOU tariff peaks are no longer aligned. This could result in a incorrect TOU tariff signal.

DMP initiatives are initiated by capacity or network constraints. Costs are more related to the real-time pricing of electricity, but still do not reflect real costs. Limited participation in DMP further makes it difficult to achieve competition. Customers receive payment only when they are required to curtail load and payment varies according to the response.

It is assumed that a substantial number of megawatts will have to be shifted or curtailed in future to manage peaks (system or network constraints). It is, therefore, critical to investigate the current impact of load management and DMP initiatives. The alignment of tariff and system peaks is critical to the success of DSM initiatives and needs to be investigated.

Customer responses to the TOU tariff signal will further indicate if the tariff signals are sufficient to achieve a desired load shape objective. It is also critical to establish if DSM initiatives can become more dynamic. Dynamic load management may increase the number of DMP participants that can be dispatched when there are system or network constraints. This will enable load management and DMP to be more in line with proven international practices. This research, therefore, intends to propose an integrated and synchronised approach to DSM initiatives.

It is critical for Eskom to have sufficient reserves to address possible supply or network constraints. The experience in the Western Cape as a result of Koeberg's Unit 1 failure, the shortages of reserve capacity in January and December 2007 and again in 2008 proved that Eskom requires additional reserve capacity [18].

1.7 Hypothesis

Load management and DMP can make a significant contribution to the electricity supply system if these initiatives are managed optimally.

DSM initiatives can be more effective if current initiatives are optimised and load management evolve into a more dynamic approach where system constraints dictate a response rather than the TOU tariff structure

1.8 Outline of dissertation

The purpose of this dissertation is to:

- investigate the current impact and effectiveness of load management and DMP initiatives;
- investigate the alignment of tariff and system peaks and the responses to the TOU tariff signal; and
- establish the ability of load management initiatives to become more dynamic.

Chapter 1 provides an introduction and background to the problem.

Chapter 2 provides a review of the literature.

Chapter 3 investigates customer responses to the TOU tariff. It further investigates the effectiveness of the TOU signal, if system peaks and tariff peaks are aligned and if system peaks are still aligned. The results of the analysis are indicated at the end of each section.

Chapter 4 investigates load management initiatives. The advantages and disadvantages of load management are determined, and the success of load shifting and the actual performance against the proposed performance are evaluated. The results of the analysis are indicated at the end of each section.

Chapter 5 investigates the advantages and disadvantages of DMP and determines if DMP can curtail load successfully. The results of the analysis are indicated at the end of each section.

Chapter 6 investigates the need for load management and DMP in the future. The growth in demand is predicted by making use of historical data and an assumed growth in historical data. The possibility of a more dynamic DSM programme is also investigated, as well as the role new tariffs can play in DSM. The results of the analysis are indicated at the end of each section. All applicable research questions and the results are also discussed in this chapter.

Chapter 7 concludes this research and highlights possible further research topics concerning DSM.

CHAPTER 2: LITERATURE REVIEW

2.1 Introduction

This chapter aims to review demand side management (DSM) practices with a view to improving or streamlining current Eskom DSM practices. Research was performed on international DSM practices in regulated and unregulated environments.

The literature review identified various advantages and disadvantages experienced by utilities. This chapter further highlights the requirements and benefits of new generation DSM.

2.2 Background on demand side management

DSM principles were initially introduced in the late 1800s and featured choice among fuels and clear pricing signals [19]. DSM further evolved due to the oil crisis in the 1970s. Electrical utilities were forced to find alternative ways of meeting the demand for electricity. Alternative ways were required when constraints were experienced or when electricity prices were extremely high.

DSM is defined as "...the planning, implementation and monitoring of those utility activities designed to influence customer use of electricity in ways that will produce desired changes in the utility's load shape, i.e. changes in the time pattern and magnitude of a utility's load. Utility programmes falling under the umbrella of DSM include load management, new uses, strategic conservation, electrification, customer generation and adjustments in market share" [21].

DSM influences the way electricity is used by customers through specific actions and programmes. DSM is orchestrated by a utility to reduce or defer the requirement for new supply side assets [20]. DSM embraces the following critical components of utility planning:

- "DSM must influence customer use. Any programme intended to influence the customer's use of electricity is considered DSM" [20];
- "DSM must achieve selected objectives. To constitute a 'desired load shape change', the programme must further the achievement of selected objectives, which must result in a reduction of average rates, improvements in customer satisfaction and achievement of reliability targets" [20]; and
- "DSM must be evaluated against non-DSM alternatives. The concept requires that selected

DSM programmes further the objectives to at least as great an extent as non-DSM alternatives such as generating units, power purchases and supply side storage devices. It is at this stage that DSM becomes part of Integrated Resource Planning" (IRP) [20].

Figure 2-1 describes the initial DSM planning model developed by the Electric Power Research Institute (EPRI). This model identified six discrete load shape objectives and technologies compatible with each load shape and end use objective. The end product was the framework for very specific DSM programmes capable of achieving a utility's load shape objective. The product of this process is still the basis for existing DSM programmes [19].

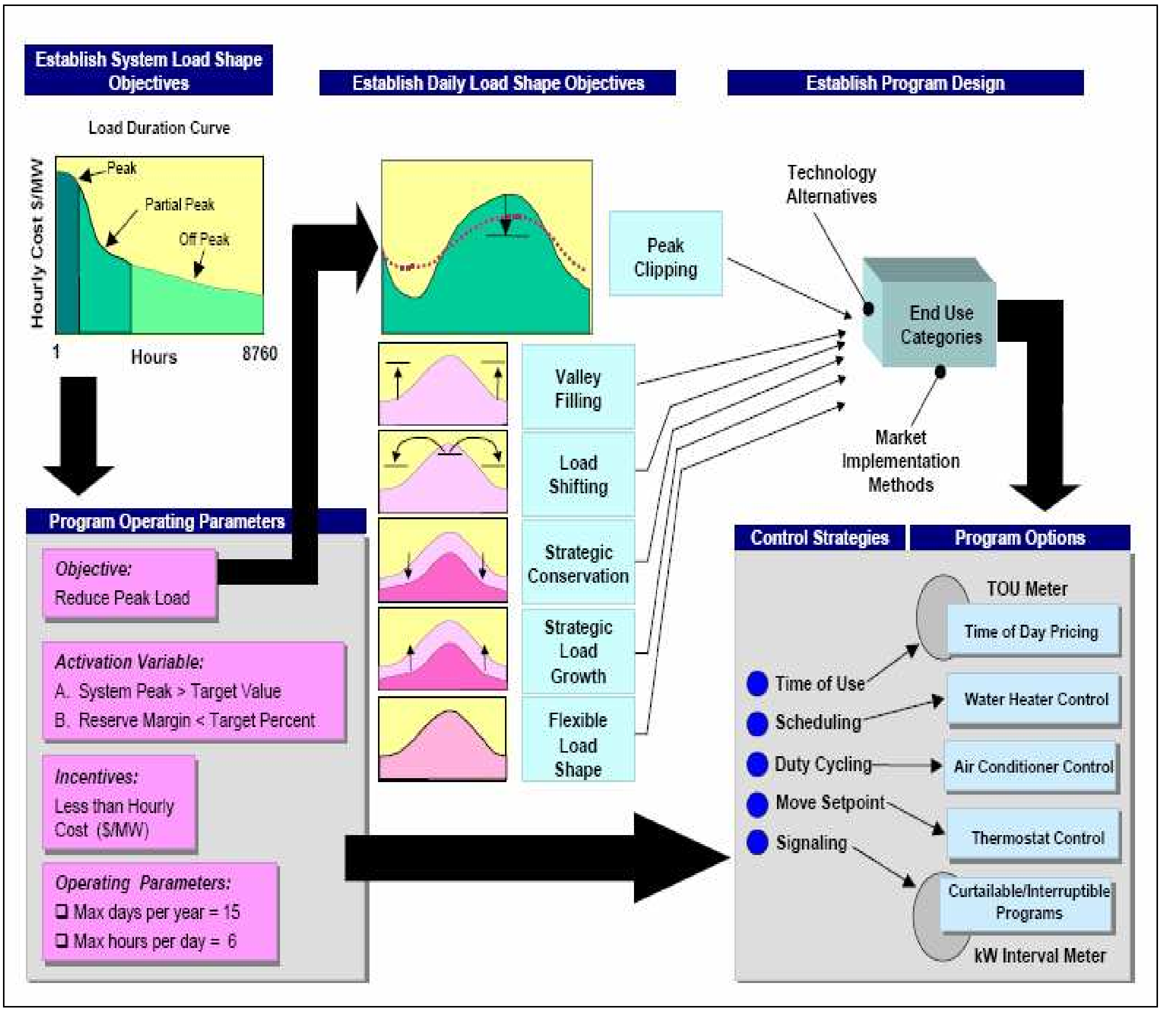

Figure 2-1: DSM planning models [19]

The six discrete load shape objectives identified by the EPRI [19] in Figure 2-1 are described as follows:

- **Peak clipping/curtailment** is a reduction of system demand during peak-load periods to decrease the size of the peak. This can be achieved by installing demand controllers, timers or utilising a building management system (BMS) to switch off certain processes at peak times.
- **Valley filling** is achieved by sending out signals for customers to consume electricity in off-peak periods. A typical example is the Eskom time of use (TOU) tariff structure that encourages customers to consume more energy in off-peak periods.
- **Load shifting** has a primary focus, which is to reduce a customer's demand during peak-load periods. Load is moved from peak-load periods to off-peak periods. This is achieved by a specific tariff signal, or it could include signals such as interruptible tariffs, real-time pricing, TOU rates, direct load control and other load management programmes. Load shifted is consumed in another time period. Load shifting is also required by the National Energy Regulator of South Africa (NERSA) as described in the Energy Efficiency and Demand Side Management (EEDSM) Policy [4].
- **Strategic conservation** is achieved by a utility sending signals to customers to reduce consumption and thereby reducing total system demand. An example of strategic conservation is energy efficiency (EE). The primary focus of EE is to reduce the use of energy both during peak and off-peak periods, typically without affecting the quality of the services provided. With energy efficiency, more advanced equipment is installed to produce the same or improved end-use services (for example, lighting, heating, cooling, efficient motors, variable speed drives and solar hot water systems), while consuming less energy than was consumed with the use of the original equipment.

EE has numerous benefits. One of these is that the environmental impacts associated with electricity generation are reduced. This also leads to fuel savings. Table 2-1 indicates the emissions and resources associated with each kW of electricity generated using coal as a resource. In South Africa, 89% of the total electricity generated is generated with coal as fuel source [9]. Another benefit of EE is that in most cases it is less expensive, cleaner and faster to implement than supply side options [2].

Table 2-1: Standard value per kW of electricity generated [9]

Fuel source	**Electricity generated**
CO^2	0.96 kg/kW
Coal	0.5 kg/kW
NOx	3.87 kg/kW
Particulate	0.28 gr/kWh
SO^2	8.79 gr/kW
H^2O	1.26 liter/kW

The implementation of EE technologies result in a reduction in a utility's sales. Because of this, EE generally happens without utility intervention and is rather guided by government policy or environmental benefits.

- **Strategic load growth** is achieved if the utility increases its sales by introducing incentives for customers to increase demand. Eskom achieved this in the 1970s and 1980s by offering very attractive long-term pricing agreements when it had excess base-load capacity. By doing this, Eskom was able to spread fixed capacity costs over a larger sales base.
- **Flexible load shape** is related to the reliability of the system. Utilities can request certain customers to reduce reliability in exchange for incentives [20]. This generally includes interruptible or curtailable load customers.

The Institute of Electrical and Electronics Engineers (IEEE) Demand Side Management Techniques Working Group did a significant amount of work to tabulate and categorise all the load management alternatives in order to achieve load shape objectives. Six load management alternatives were identified. These are end-use control, utility equipment control, energy storage, dispersed generation, customer DSM promotions and performance improvement [21].

2.3 DSM and integrated resource planning

Integrated resource planning (IRP) is a planning process for electricity utilities. The process evaluates many different options for meeting future electricity demands and selects an optimal mix of resources that minimises the cost of electricity supply, while meeting reliability needs and other objectives [22].

Normally, IRP programmes include many supply side measures, ranging from utility-owned power plants, independent power plants, power purchases, cogeneration, renewable energy sources and DSM programmes. International studies found that cost-effective DSM programmes can reduce electricity use and peak demand by approximately 20 to 40% [22]. By financing IRP and DSM efforts through electricity tariffs, costs to the average customer are reduced and a higher level of system reliability and security are achieved [22].

Depending on the time of day and the consumption patterns of a customer, load changes may be integrated into the utility's scheduling and dispatch decisions on a day-ahead basis. If managed optimally, changes in the load could offset additional capacity, which lowers the average variable electricity costs. The long-term impact of DSM hinges on reducing system peak demand [6].

Figure 2-2 indicates the impact of DSM initiatives that reduce peak demand and directly postpone the need for utilities to invest in power plants, power lines and other capacity-driven infrastructure. This produces substantial avoided cost savings. DSM programmes designed to reduce capacity needs are valued according to the marginal cost of capacity. Marginal capacity is assumed to be a peaking generator specifically added to run a few hours a month to meet the system demand [6].

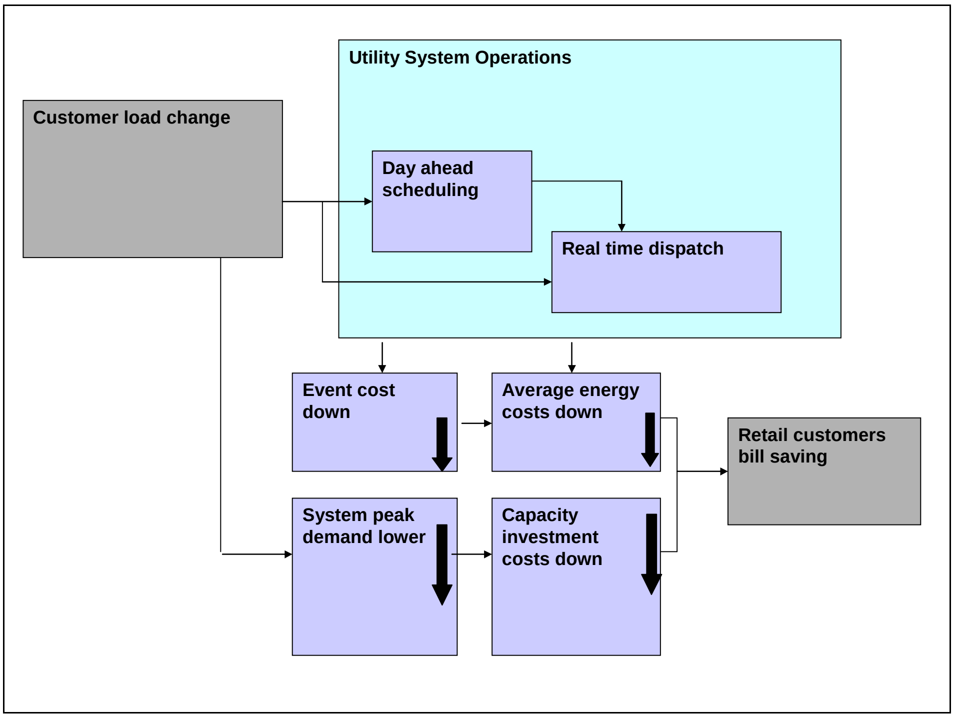

Figure 2-2: Impacts of DSM programmes (vertically integrated utilities) [6]

2.4 DSM in regulated and unregulated environments

Utilities have operated DSM programmes in regulated and unregulated environments for many years [23]. In restructured (unregulated) electricity markets, load shifting and curtailment is known as demand response (DR). The characteristics of generation has the effect that when demand approaches the installed capacity, each increment of demand imposes increasingly more costs than the previous increment [6]. “In other words, the marginal cost of electricity becomes more sensitive to changes in demand when demand is already high.” [6]

In the South African electricity supply industry (ESI), demand is very high in relation to supply capacity. This has been reflected in the high primary energy purchases during the 2007 financial year.

The main differences between DSM programmes in regulated and unregulated environments are indicated in Table 2-2. It is evident that customers in unregulated electricity markets have more choices than customers in regulated market or vertically integrated utilities. The available choices influence a customer’s decision to participate in any particular event. DSM in regulated and unregulated markets is further described in section 2.4.1 and 2.4.2.

Table 2-2: DSM programmes in regulated and unregulated markets [19]

Unregulated electricity markets	**Vertically integrated utilities/ regulated electricity markets**
Electricity prices more elastic	Electricity prices inelastic
Customers respond to spot prices	Customers respond to long run marginal pricing
Multiple load shape objectives	Options usually designed to address limited load shape objectives
Participation based on economic decisions	Participation often limited to customers with specific end-use characteristics or ability to provide minimum load reduction
Market value charged for service	Fixed incentives: could over- or under-reflect market value of load
Market value paid to customers	Fixed incentives: could over- or under-compensate customers for load contributed

The US Department of Energy identified direct, collateral and other benefits that are realised by most or all DSM participants [6]. These benefits are indicated in Table 2-3. Most of the benefits are applicable to regulated and unregulated utilities.

Short-term market benefits include savings in variable supply costs through energy efficiency. In regulated utilities, short-term benefits are limited to avoided variable supply costs [6]. Long-term market benefits include the reduction of system peak demand, and the reduction of the need for additional generation capacity or other infrastructure. It further enables the utility to better manage constraints. Avoided capacity investment is, therefore, a significant source of savings. However, to reduce capacity costs, DSM programmes must be able to shift/curtail load at high-demand times throughout the year [6]. Reliability benefits include a reduction in the probability and the extent of forced outages. Reliability benefits can be valued at the reduced risk of an outage [6].

Table 2-3: Benefits of DSM [6]

Type of benefit	**Recipient(s)**	**Benefit**		**Description/source**
Direct benefits	Customers undertaking demand response actions	Financial benefits		• Bill savings • Incentive payments (incentive-based demand response)
		Reliability benefits		• Reduced exposure to forced outages • Opportunity to assist in reducing risk of system outages
Collateral benefits	Some or all customers	Market impacts	Short-term	• Cost-effectively reduced marginal costs/prices during events • Cascading impacts on short-term capacity requirements and load serving entity (LSE) contract prices
			Long-term	• Avoided (or deferred) capacity costs • Avoided (or deferred) transmission and distribution infrastructure upgrades • Reduced need for market interventions (for example, price caps) through restrained market power

Type of benefit	Recipient(s)	Benefit	Description/source
		Reliability benefits	• Reduced likelihood and consequences of forced outages • Diversified resources available to maintain system reliability
Other benefits	Some or all customers independent system operators/ regional transmission organisation load serving entity	More robust retail markets	• Market-based options provide opportunities for innovation in competitive retail markets
		Improved choice	• Customers and load serving entities can choose desired degree of hedging • Options for customers to manage their electricity costs, even where retail competition is prohibited
		Market performance benefits	• Elastic demand reduces capacity for market power • Prospective demand response deters market power
		Possible environmental benefits	• Reduced emissions in systems with high-polluting peaking plants
		Energy independence/ security	• Local resources in states or regions reduce dependence on outside supply

2.4.1 DSM in regulated electricity markets/vertically integrated utilities

Vertically integrated utilities are responsible for generation, transmission, distribution and retail services and are indicated in Figure 2-3. These utilities make capacity investment decisions based on their IRP. The investment plan is approved by an independent regulator. The regulatory framework provides utilities special incentives to adopt DSM resources. These incentives are offered as valid alternatives to supply side resources in a way that does not lead to reduced profits, and ensure an optimal mix of resources at minimum costs.

Retail rates are based on cost to supply power, operating and maintenance costs, the average cost of supplying electricity and the profit margin. Capacity investments are usually fully recovered over a period of time along with a pre-determined return on investment [6]. Proper implementation of DSM initiatives can result in significant savings to customers in the long term. Eskom is a vertically integrated utility and operate in a regulated environment.

Figure 2-3 illustrates the short-term impacts for vertically integrated utilities. “The supply curve typically reflects the utility’s supply costs, including its own generation plants and incremental wholesale power purchases. If demand is forecasted to be ***Q***, then the demand reduction that moves consumption to $\boldsymbol{Q_{DR}}$ results in an avoided utility supply costs” [6]. The avoided supply costs will be $\boldsymbol{\Delta C\ (C - C_{DR})}$.

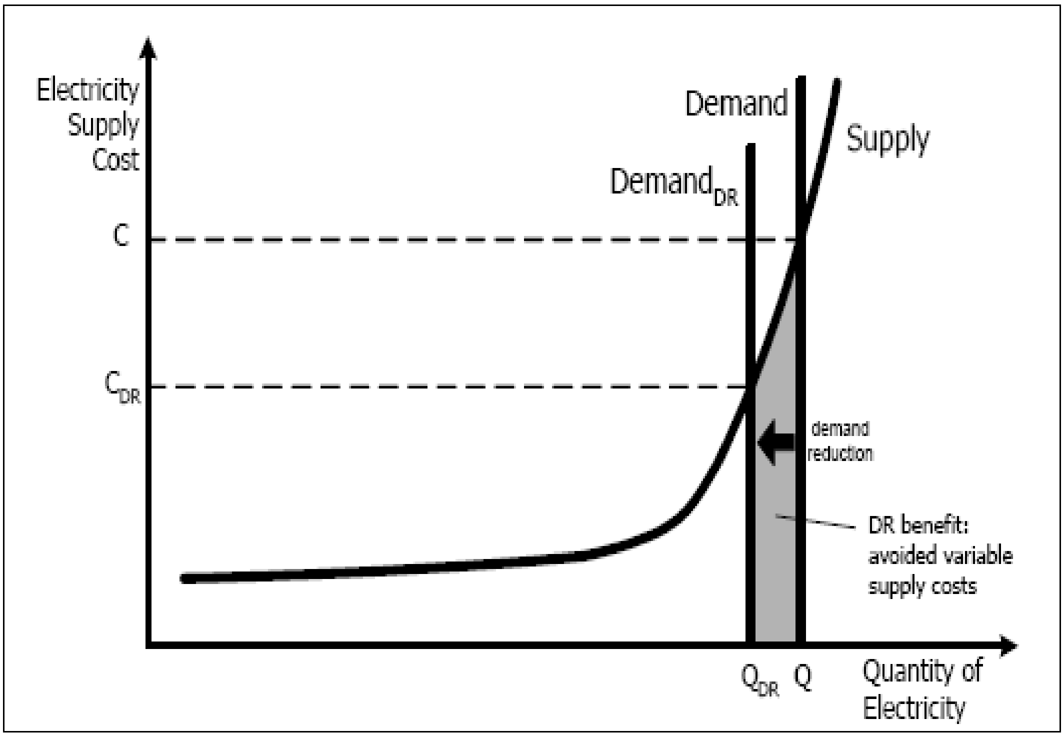

Figure 2-3: Impacts of load management for vertically integrated utilities or regulated markets [6]

In this environment, DSM is most useful to improve asset usage, to create flexibility on the system for reliability and security of supply, to defer capacity investment or assist in times when capacity shortages are experienced. The value of the initiative will determine how customers are compensated for their participation.

2.4.2 DSM in unregulated electricity markets

“Economic theory asserts that the most efficient use of a resource occurs when consumption decisions are based on prices that reflect the marginal cost of supply.” [6] In competitive markets, investment decisions are largely left to the market [24]. DSM initiatives are triggered by economic considerations, as well as system conditions [25]. Generators offer bids according to their marginal costs and utilities bid their expected load forecast. The outcome of this is a demand curve with the market clearing price equal to the price of the last generator dispatched to meet the demand.

Figure 2-4 represents the impact of DSM in wholesale markets. A demand reduction from $\boldsymbol{Q}$ to $\boldsymbol{Q_{DR}}$ represents the avoided variable costs, as well as a reduction in the price of all the energy purchased in the market $\Delta \boldsymbol{P}$ ($\boldsymbol{P} - \boldsymbol{P_{DR}}$) *[6]*. The extent of the saving from the price reduction depends on the quantity of energy purchased in the spot market. Bilateral contract prices also decrease over time if real-time prices and day-ahead prices decrease over time [6].

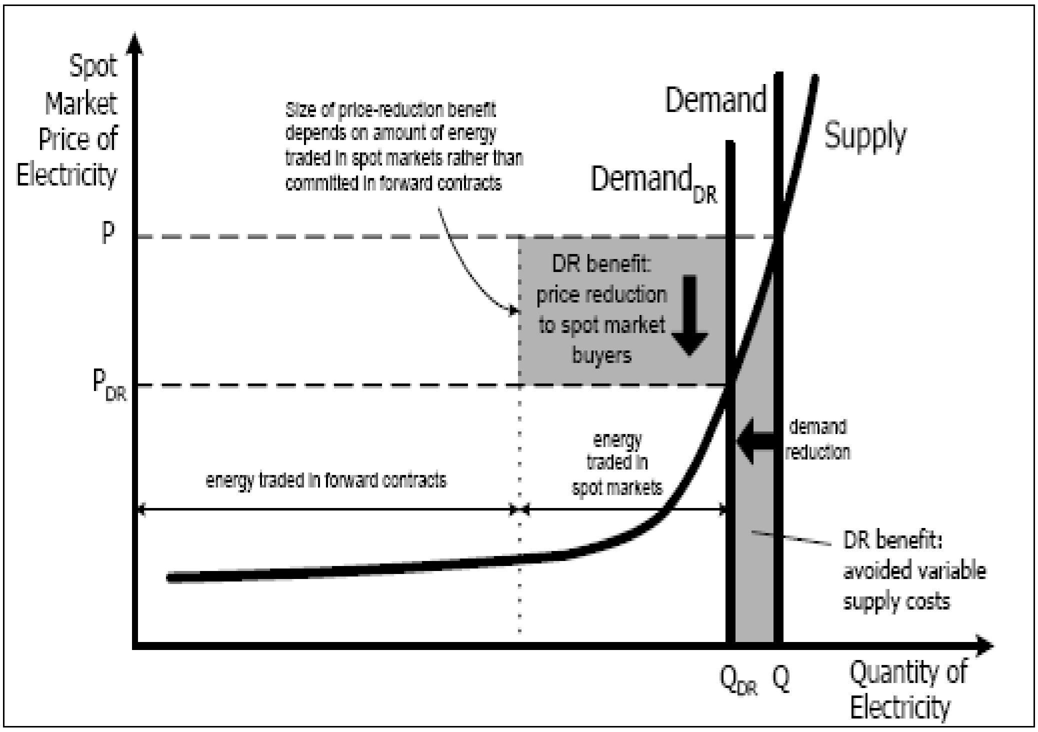

Figure 2-4: Impacts of load management for deregulated markets/utilities [6]

As in the regulated market environment, load shifting/curtailment is also useful in the unregulated environment to improve asset usage, to create flexibility on the system for reliability and security of supply, to defer capacity investment or assist in times when capacity shortages are experienced. The customer will receive the spot price of electricity as payment if the customer responds.

2.5 Effect of load shift on aggregate demand

The role of DSM is to modify the load shape in chunks large enough to reduce cost or to ensure a higher available reserve margin during a specific time. Small adjustments in end-use appliance usage enabled by simple control schemes can have a tremendous potential effect on the system. During the summer of 2000, peak load in California was approximately 51 000MW and the residential air conditioning load contribution was approximately 14% [26]. Ilic, Black and Watz calculated that a reduction of 83% in air conditioning load lead to an overall demand reduction of 12% during the system peak [26].

Figure 2-5 shows the effect of reductions between 20 and 35% in air conditioning load on the daily demand curve. A 35% reduction in the air conditioning load lowered the system peak by almost 6% and did not create a new system peak [26]. This example proves that load reduction or load shifting can smooth out the peaks during certain times of the day [26].

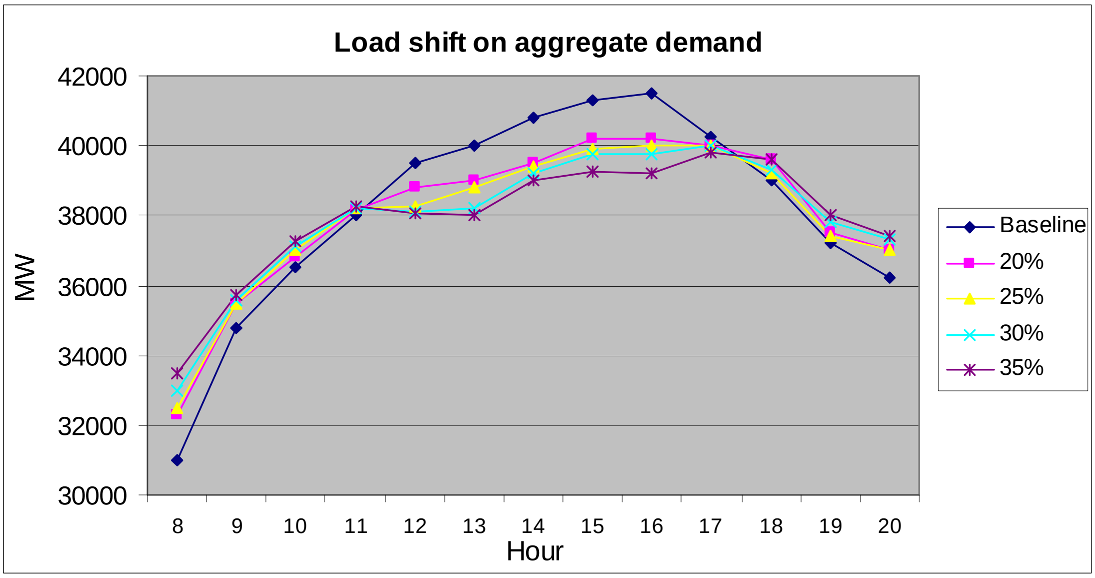

Figure 2-5: Effect of load shift on aggregate demand (air conditioning) [26]

2.6 Declining investment and participation in conventional DSM offerings

International restructuring initiatives, growing emphasis on customer choice and the emergence of wholesale electricity markets increased the need for DSM initiatives. However, an EPRI report published in 2003 identified that what should have been a growing initiative – investments in DSM initiatives – has been declining [19]. Figure 2-6 highlights the declining investment in DSM from 1993 to 1999.

EPRI identified the following reasons for the decline:

- Customers prefer alternatives that provide flexibility and economic choice. Customers also demonstrate a declining acceptance to options with fixed reductions that limit their ability to control their own operations. [19]
- High-utility focus on reliability-based DSM ignores customer needs for alternative cost management options. [19]
- Load shifting and curtailment have accumulated regulatory and operating concerns that substantially limit their perceived reliability and economic value [19].

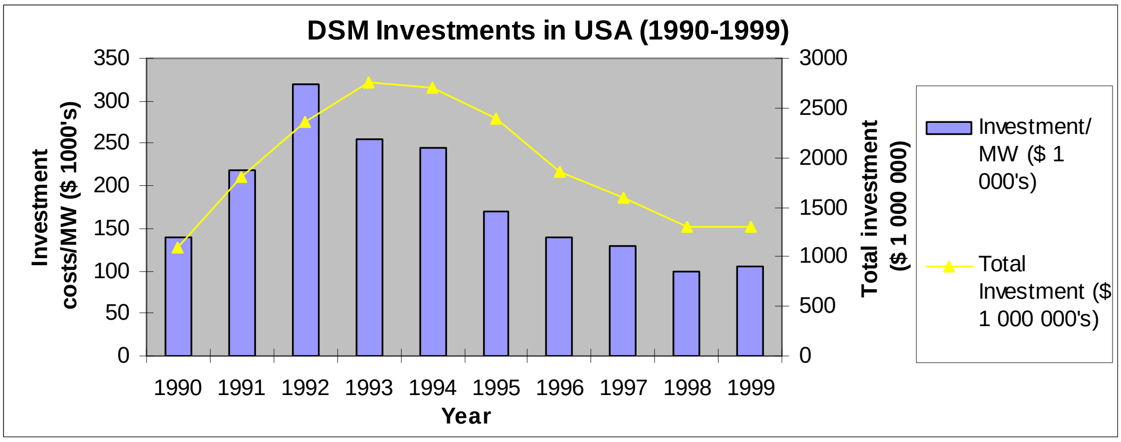

Figure 2-6: DSM investments in the USA 1990 to 1999 [19]

The US Department of Energy further indicated that its studies suggest that participation rates may have been adversely affected by the fact that customers incurred significant upfront costs without the assurance of a guaranteed benefit stream of payments [27]. Utilities and regulators are, therefore, reluctant to invest in problematic programme offerings or DSM options that were once considered popular offerings.

"Commitments to fixed demand reductions that are often at odds with business needs or other service concerns, the lack of customer control and inadequate incentives all contributes to the decline" [19]. DSM options are, therefore, challenged to provide better technological capabilities, incentive structures and operating plans. New generation DSM provides flexibility that addresses multiple load shape objectives, allows a great number of customers to participate, allows customers to receive a variety of incentives and permits customers to participate in a variety of programmes.

New generation DSM offerings are acceptable to customers and utilities achieve their load management objectives if the right signals and incentives are applied. DSM is also considered to be a critical component in maintaining a reliable electricity network.
EPRI established that the ability to address multiple load shapes can provide energy companies with the flexibility to simultaneously address infrequent reliability-driven emergency operations, as well as well as day-to-day risk and price management strategies. EPRI further identified that DSM options must incorporate four basic design features [19]. These options are as follows:

- **Multiple load shape objectives:** All energy markets (regulated or unregulated) experience periodic episodes of volatility. DSM can mitigate this at a fraction of the costs of conventional generators. Flexibility also allows for customer choice [19].
- **Pricing and incentives:** Pricing should reflect system conditions or operating conditions. Pricing based on this method allows each customer to tailor actions in order to balance the cost of service with the balance of service [19].
- **Advanced metering:** Metering technologies need to support customer options and are a necessary component of DSM projects. This will also enable utilities to compensate customers fairly for their response [19].
- **Condition for electric service:** DSM options should be available to all customers and this must become a way of life [19].

2.7 Conclusion

The value of lost load (VOLL) is a measure of what customers are willing to pay in order to avoid outages. This value differs between customer classes and groups, but is mostly greater than the retail price of electricity. Electricity costs to a country’s economy are based on supply costs and shortage costs. DSM technological progress could offer alternatives to substantially reduce shortage costs [28].

DSM programmes are effective in reducing peak demand. It enables utilities to achieve a specific load shape objective and has been used effectively during emergencies to reduce load in a short space of time. DSM investment declined in the late 1990s. This decline was mainly due to limited customer choice and fixed incentives, coupled with fixed reductions and uncertainty with the return on investment. It was also noted that customer responses should be guided by network constraints and not by fixed contracts.

The review of this literature highlights that demand reductions is effective in electricity markets.

In the absence of a competitive electricity market, DSM initiatives in South Africa might face challenges not experienced in international markets. Declining customer participation may also indicate the level of sustainability for DSM initiatives.

This study will evaluate Eskom DSM with the international best practices identified in this chapter. This study will further investigate DSM practices in Eskom and establish if load management initiatives can become more dynamic to ensure active customer participation.

CHAPTER 3: TOU TARIFF SIGNAL AND DEMAND

3.1 Introduction

Time of use (TOU) tariffs are an approximation of real-time prices [29] and reflect average costs of generation, transmission and distribution, as well as a retail component. Prices are fixed in advance and usually differentiate between seasons and specific times of each day. International data shows that most TOU participants use less electricity during high and standard tariff periods and more electricity during off-peak periods.

The purpose of this chapter is to investigate the following:

- The response of customers to the TOU tariff
- Whether system peaks and TOU peak periods are aligned.

The results of the analysis in this chapter will demonstrate whether the TOU tariff represents the correct signal to shift load effectively out of system-peak periods. This chapter will further highlight possible shortcomings of the current TOU tariff.

3.2 Response to TOU tariffs

TOU tariffs are fixed for a year in advance and are not based on real-time prices. The price to generate electricity changes as demand and supply changes. Internationally, the objective of TOU tariffs is to reduce demand at certain times of the day in order to achieve a desired load shape. The significant disadvantages of TOU tariffs are that prices do not reflect real-time events [30].

The intention of the Eskom TOU tariff is to send clear pricing signals to customers. This pricing signal reflects the long run marginal cost (LRMC) of electricity. In turn, significant load shape objectives can be realised when customers take advantage of these rate options [31]. It is important for Eskom to know what the response is to a specific tariff signal.

Knowing the correct customer response to tariff signals will assist in the development of further pricing strategies. It will also assist in the development of DSM objectives [19] and in the effective planning and development of integrated resource planning (IRP). The TOU tariff was developed by Eskom and underwent significant changes in 2002, especially as far as the price differentiation between the high and low-demand seasons was concerned [32].

Eskom's Resources and Strategy Department initiated a research project in 2003 with the intention to quantify and model various customer responses to the TOU tariff. During this study, data from 2001 was used as a baseline [32]. The study was based on data for 2003 and the results proved that the TOU tariff signal led to a system-peak demand reduction of between 400 and 500MW (between 18:00 and 19:00 on winter weekdays) [32].

The initial observation done in 2003 was subject to influences such as the strength of the South African rand, labour actions, commodity prices and the ability of customers to respond to the TOU tariff. To obtain more certainty on the impact of the tariff signal, further research was undertaken in 2005 [32]. The intention of this research was to factor in aspects such as exchange rates, labour actions and commodity prices and to correlate this information with the various customer responses. Sample design techniques were used to model the response and hourly load data was filtered to remove significant changes in the data [32].

The software that was developed during the study [32] was used to filter various customer data. The customer data analysed in this section is applicable to all customers on the TOU tariff and does not apply to load management customers only. Information for the customers was grouped into 24 categories [32] and the data is represented according to the average weekday load for each customer group. The customer groupings were made up of the following customers:

- Casting of metals, which includes conventional iron and steel, ferrochrome, ferromanganese and ferrosilicon [32]
- Manufacture, which includes basic chemicals, motor vehicles, other textiles and plastic products [32]
- Mining, which includes coal and lignite, diamonds, gold, uranium, iron ore and non-ferrous metals [32]
- Petroleum refineries/synthesis [32]
- Silicon metals [32]
- Stainless steel [32]
- Titanium [32]
- Zinc [32]

For the purpose of this analysis, each of the abovementioned customer groupings (casting of metals, petroleum refineries, mining of diamonds, mining of coal and lignite, etc) were regarded as individual customer groups to ensure confidentiality.

Customers were classified according to 24 different groups. Customer Group 1 had the most fluctuations in seasonal consumption patterns, while Customer Group 24 had the least fluctuations in seasonal consumption patterns.

Responses for all the customer groups were filtered for the various years, from 2003 to 2006, as well as seasons. Figure 3-1 shows the percentage fluctuations per season for the various customer groups. Consumption patterns for Customer Group 1 fluctuated with 25.8% between the high and low-demand season, while consumption for Customer Group 24 fluctuated with 2.1%. The average fluctuation per season was 9.9%. The fluctuation per season illustrates the following characteristics:

- Some customer groups are more sensitive to higher electricity prices than others.
- Some customers seem able to vary their activities in order to respond to the TOU tariff signal.

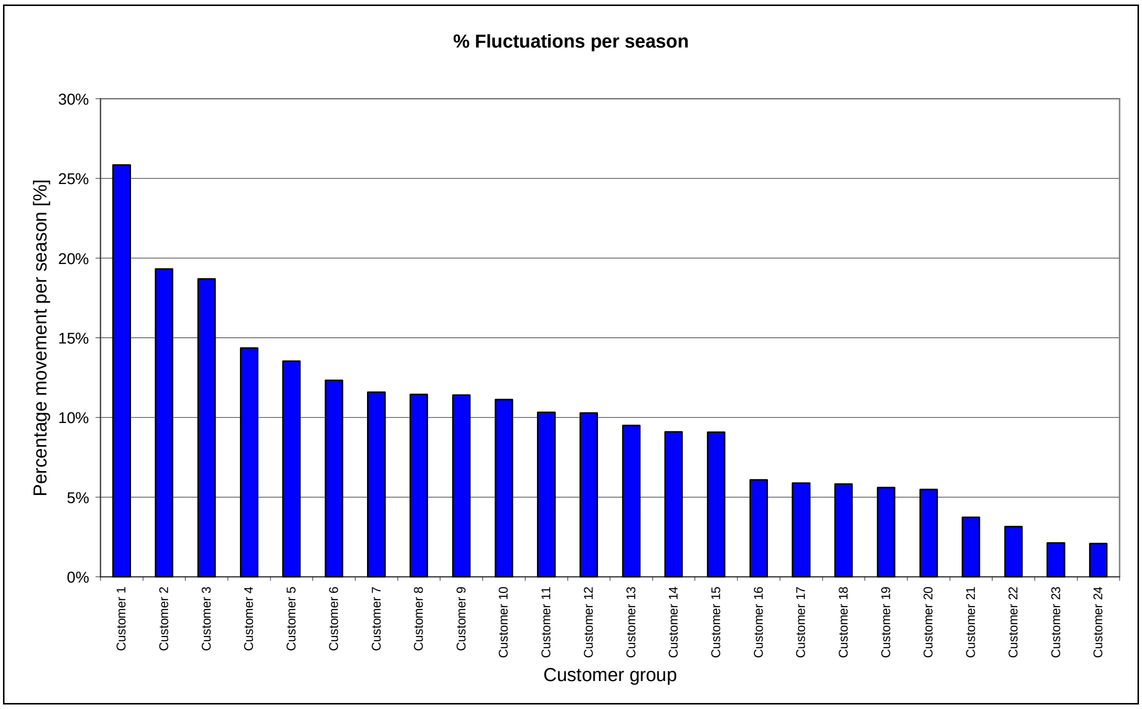

Figure 3-1: Fluctuation per season for various customer groups on the TOU tariff [32]

Average weekday profiles for three of these customer groups were selected for analysis. The three groups represent a good balance in fluctuation between the high and low-demand season. The groups that were selected are group 1 with 25.8% fluctuation, group 7 with 11.6% fluctuation and group 19 with a 5.5% fluctuation between seasons. The average weekday profiles for the three customer groups are shown in figure 3-2, 3-3 and 3-4.

Figure 3-2 shows an average weekday profile for Customer Group 1 during 2005 and 2006 for both the high and low-demand season on the TOU tariff. As indicated in Figure 3-1, this Customer Group had a 25.8% fluctuation between seasons. This fluctuation is also visible in Figure 3-2.

Figure 3-2 further shows the customer's ability to respond to TOU peak periods. The only period without sufficient incentive for Customer Group 1 to respond is during the TOU evening peak period (low-demand season). By analysing this response, it is clear that this customer group has the ability to shift load and that they might possibly benefit financially by shifting load according to the TOU tariff signal.

It is possible that due to production processes, Customer Group 1 is able to respond to the TOU morning peak irrespective of the season. It is evident that the pricing signals for the high-demand season have an impact on this customer group's decision to respond. Customer Group 1 is responding to the TOU tariff signal in the high demand season. It is likely that this customer would have responded during the evening TOU peak period (low-demand season) if the tariff signal was sufficient during this season.

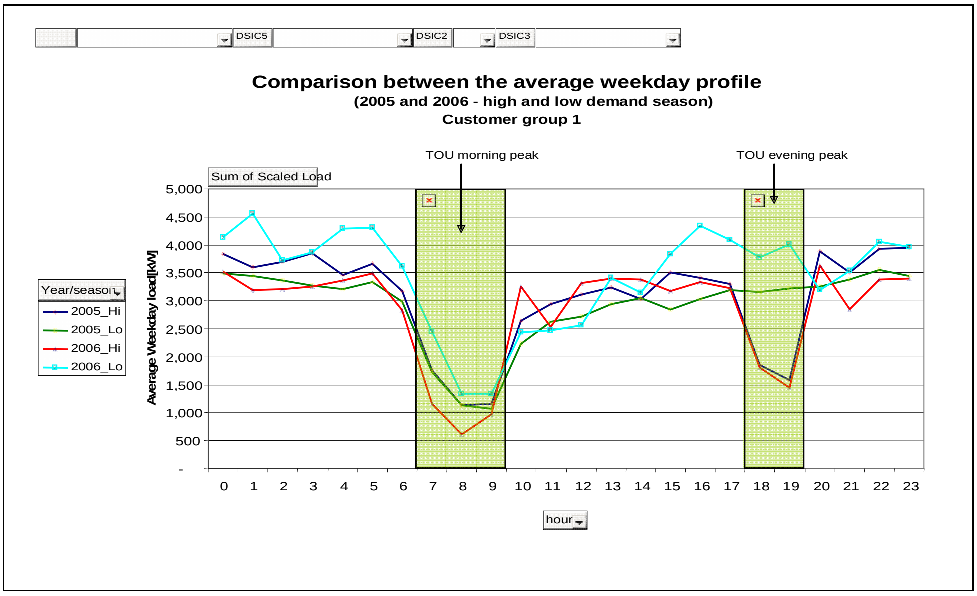

Figure 3-2: Average weekday profile for Customer Group 1 during 2005 and 2006 (high- and low-demand season) on the TOU tariff [32]

Figure 3-3 shows an average weekday profile for Customer Group 7 during 2003, 2004, 2005 and 2006 (high-demand season) on the TOU tariff. For all the years between 2003 and 2006, this customer group has been responding to the TOU morning peak period. During 2003 and 2004, this customer group also responded to the TOU evening peak period. There was no substantial reduction in the demand patterns during 2005 and 2006 during the TOU evening peak period. This customer group's demand has also increased annually and shows a steady growth from 2003 to 2006.

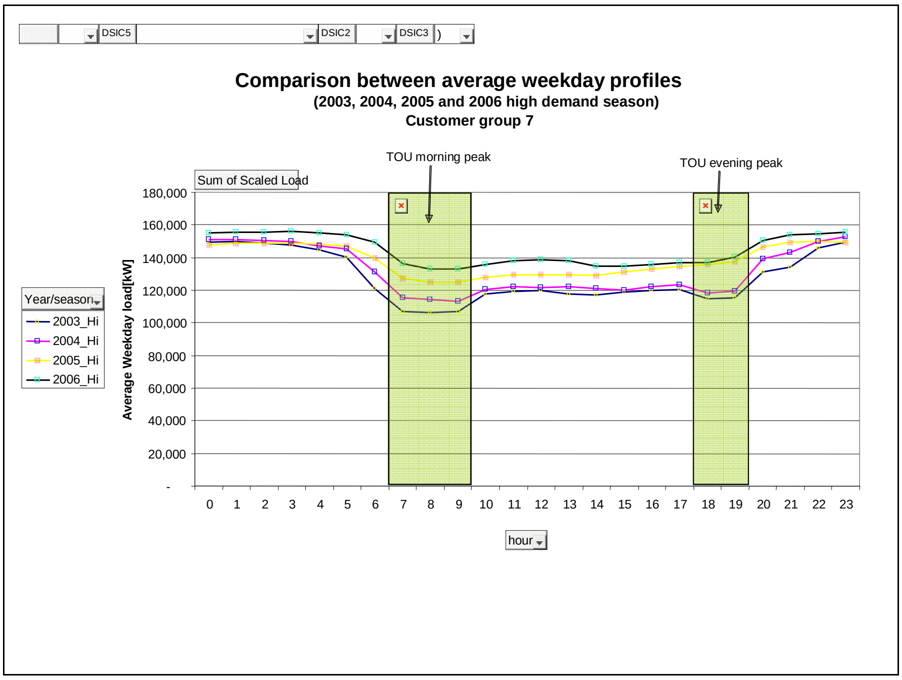

Figure 3-3: Average weekday profile for Customer Group 7 during 2003, 2004, 2005 and 2006 (high-demand season) on the TOU tariff [32]

Figure 3-4 shows an average weekday profile for Customer Group 19 during 2004, 2005 and 2006 (high- and low-demand season) on the TOU tariff. The highest average consumption occurred in 2005 during the low-demand season, while the second highest average consumption occurred in 2006 during the high-demand season. It is clear that this customer group did not respond to the TOU tariff signal. The customer group's load is gradually increasing and the incentive to reduce consumption during TOU peaks does not seem to be sufficient to encourage this customer group to reduce demand during TOU peak periods.

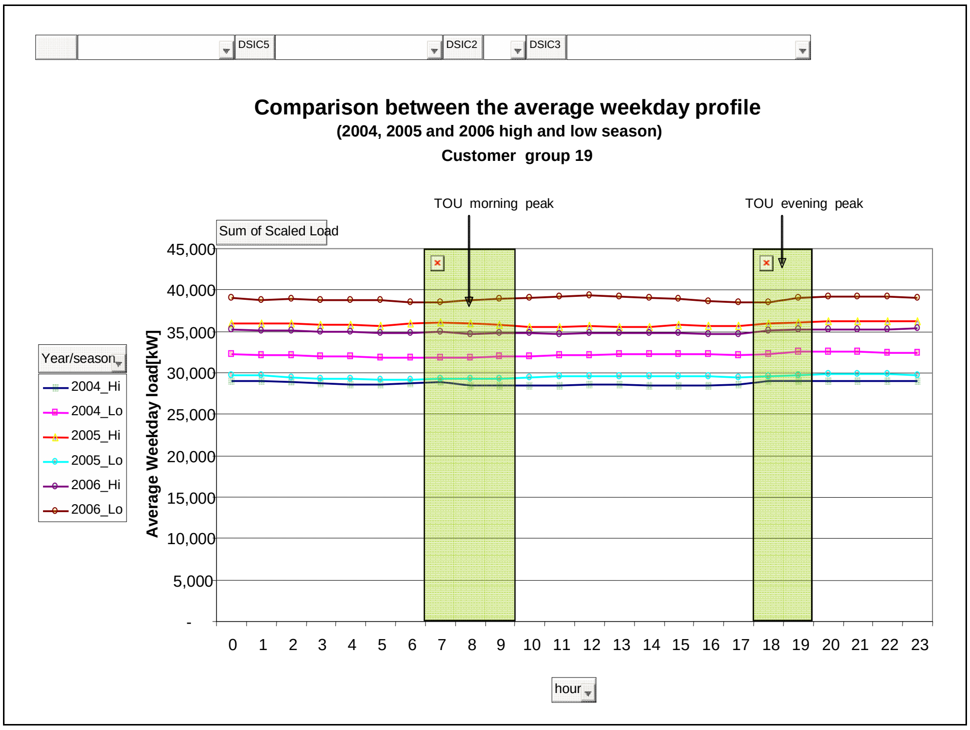

Figure 3-4 Average weekday profile for Customer Group 19 during 2004, 2005 and 2006 (high- and low-demand season) on the TOU tariff [32]

3.2.1 Results

By analysing the results of the various responses to the TOU tariff signal, it is quite obvious that certain customer groups respond to TOU tariff signals, while others do not respond at all. Customers may not necessarily respond to economic incentives alone [31]. Environmental, political and other factors might also play a role. However, in most cases economic incentives play the biggest role in a customer's decision to respond to a TOU tariff signal [31].

The results in this section prove that customer groups respond more to the TOU tariff during the high-demand season compared than in the low-demand season. A higher tariff during the low-demand season could encourage customers to respond during this season. Higher tariffs will have economic implications but the correct tariff signals should not lead to the creation of new constraints.

3.3 System peaks

A specific amount of operating reserves are required at any given time period. The operating reserves secure capacity that will be available for the reliable and secure balancing of supply and demand following a contingency loss.

The reserves that might be required varies, but the loss of a unit at Koeberg, three units at conventional coal-fired power stations, and the Cahora Bassa feed will result in a loss of 920MW, 1 800MW and 1 800MW respectively [33]. Operating reserves are therefore required to be not less than 1 800 MW [33]. The South African Grid Code are used as a guideline in this section and defines five categories of operating reserves: instantaneous reserves, regulating reserves, supplemental reserves, emergency reserves and ten-minute reserves.

Operating reserves of less than 1 800MW do not imply that an outage is eminent. This simply indicates that the required reserves necessary to support the system in case of a contingency loss are not adequate. When the operating reserves are less than the required 1 800 MW [33], this might be a sign of system constraints.

Day-ahead forecasts can be attributed to factors that can be measured, such as behaviour or people, weather variables and economic trends [20]. This is a fairly accurate estimation and data for the available operating reserves, which includes day-ahead estimations, as well as actual system data, was collected and analysed. The period represented by the data ranges over a 20-month period between January 2006 and September 2007 and represents the high- and low-demand seasons. Where the reserves were less than 1 800 MW in any hour, as prescribed as a minimum by the grid code [33], this was added to establish in which hour of the day constraints were more likely to occur.

Figure 3-5 was derived from actual data that was sent out and indicates the percentage of times that the operating reserves were less than the minimum prescribed reserves [33]. The results are grouped according to the TOU tariff periods and the periods in figure 3-5 are represented in red, yellow and green for the high, standard and low demand-periods respectively, as defined in Chapter 1. The results show that 39.71% of the constraints occurred during the TOU peak period, 47.79% occurred during the standard TOU period and 12.5% occurred during the TOU off-peak period.

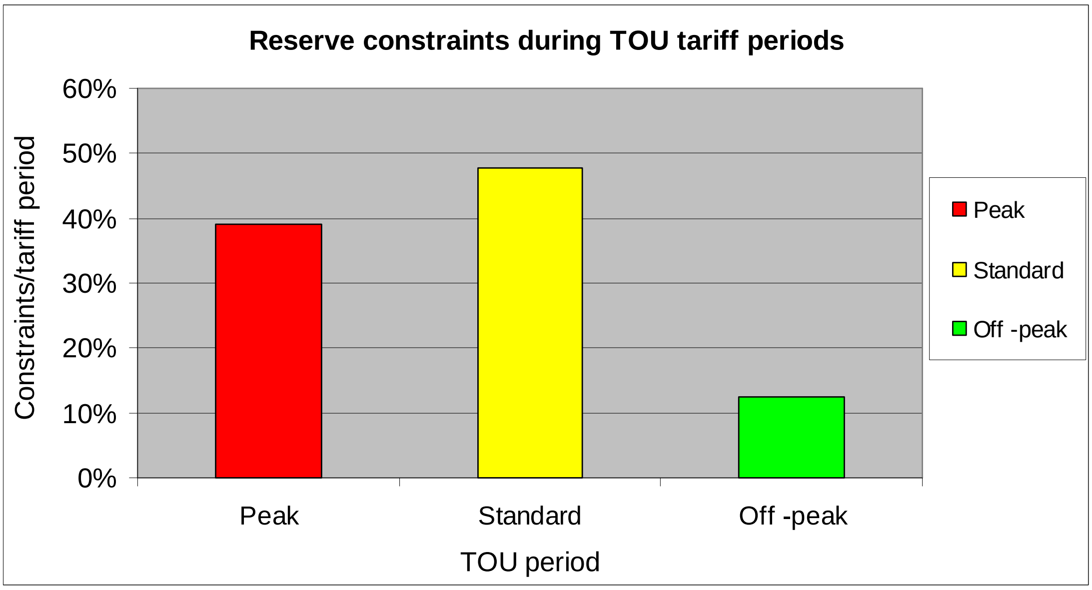

Figure 3-5: Reserve constraints during the TOU tariff period

Figure 3-6 represents the day-ahead estimates, as well as the actual data sent out. The constraints are represented as a percentage for each hour of the day and the TOU periods in figure3-6 are represented in red, yellow and green for the high, standard and off-peak periods respectively, as defined in Chapter 1. By analysing Figure 3-6, it is clear that the TOU peak period is still the time when most constraints are experienced on the network.

However, the standard TOU period after the morning TOU peak period and the hours before and after the evening TOU peak period also represent constraints. This can be attributed to growth in electricity consumption and, to a lesser extent, to the possible creation of new peaks due to load shifting. It is also noticeable how accurately the day-ahead estimations were done in comparison to the actual reserve constraints.

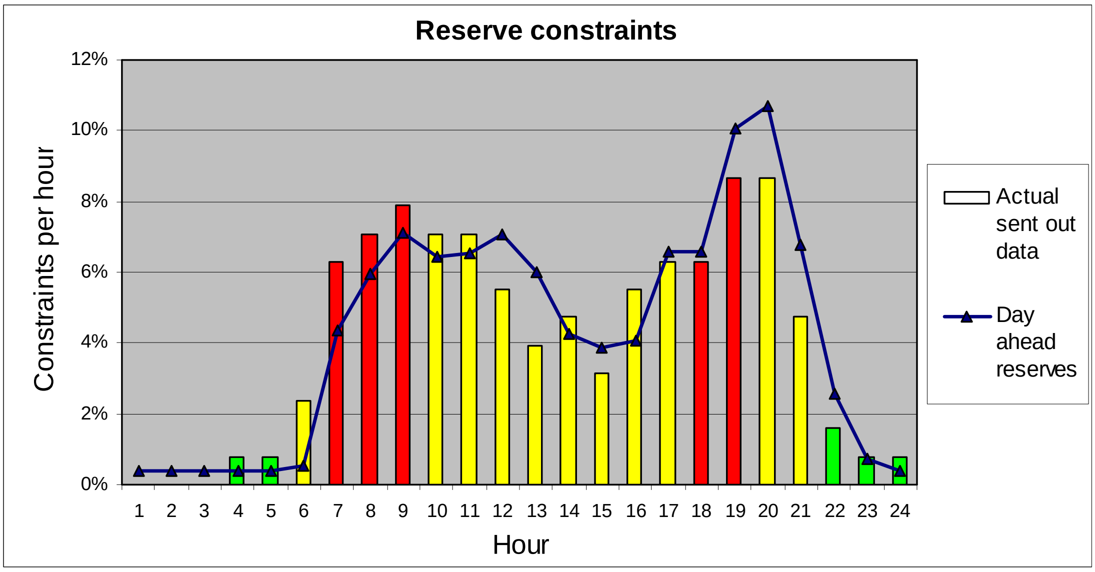

Figure 3-6: Hours of the day with reserve constraints indicated as a percentage per hour

3.3.1 Results

The analysis in this section highlights the fact that constraints are experienced during the TOU tariff periods. Further constraints are also experienced during standard TOU periods. The results show that more constraints occur during standard TOU periods (47.79%) than during peak periods (39.71%). To shift load out of the TOU tariff period could lead to further constraints in the periods after the TOU tariff periods.

3.4 Alignment of peaks

The development of a TOU tariff is generally a huge and detailed process. One of the factors that influenced the development of the Eskom TOU tariff is the demand profile, which indicates the times of day when the highest consumption occurs, as well as its duration. To establish if the system peaks remained aligned and to establish if the TOU peaks and the system peaks are still aligned, actual sent out data between 1990 and 2007 was analysed.

Weekly sent out profiles for the various years were compared and are presented in this section. The weekly profiles for the different years remained relatively constant. The analysis was repeated for a number of weeks during a year and the responses still remained relatively constant. For the purpose of representing the analysis of the data in this section and the sections that will follow, Week 4&5 and Week 27&28 was selected for analysis. The basis for this selection:

- The profiles remained relatively constant except for seasonal differences.
- Week 4&5 is during the low-demand TOU tariff season and week 27&28 is during the high-demand TOU tariff season. Both weeks fall in a period when industry operates normally.
- Week 27&28 represents a very cold time of the year, when excess electricity is generally consumed.

Figure 3-7 represents data sent out for Week 4&5 during the low-demand season (weekdays only) between 1990 and 2007. Only seven of the 17 years are presented for practical reasons. The results for the 17 years remain relatively constant and these seven years represent a good balance. Figure 3-7 clearly shows that, except for a steady increase in demand over the years, consumption patterns have not changed much over the past 17 years.

The evening peak is generally higher than the rest of the day. Slightly higher consumption occurs during the morning and evening TOU peak periods if compared to the rest of the day, and consumption declines substantially between 21:00 in the evenings and 06:00 in the mornings. The vertical lines show morning and evening peaks are still aligned (blue lines- highlight morning peaks and red lines highlight evening peaks).

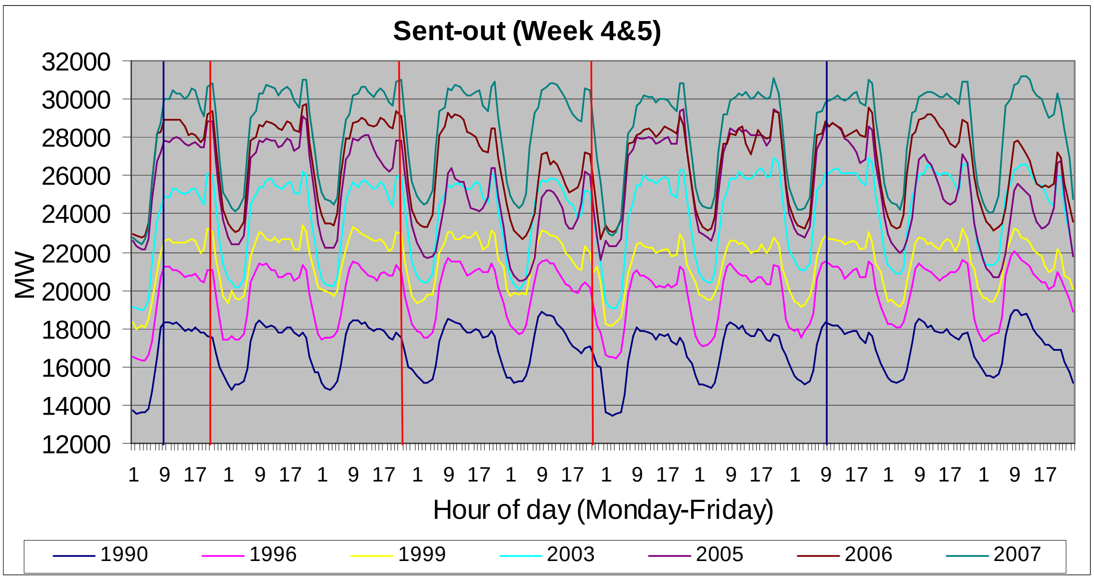

Figure 3-7: Sent out load profile for Week 4&5 (Low-demand season)

Figure 3-8 represents data sent out for Week 27 and 28 for the high-demand season (weekdays only) between 1990 and 2007. Once again, only seven of the 17 years are presented. Figure 3-8 shows that consumption patterns did not change much, except for the increase in the overall demand over the years. The evening peaks are generally higher than the morning peak. The morning and evening peaks are clearly visible and consumption reduces substantially between 21:00 in the evening and 06:00 in the mornings. The vertical lines show morning and evening peaks are still aligned (blue lines-highlight morning peaks and red lines highlight evening peaks).

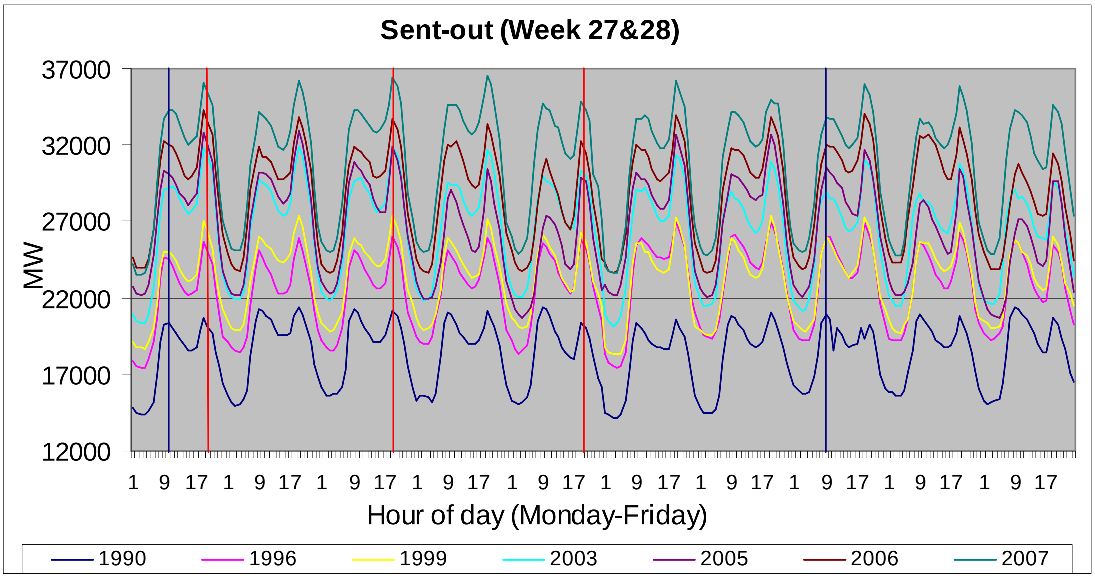

Figure 3-8: Sent out load profile for Week 27&28 (High-demand season)

3.4.1 Results

Except for the growth in demand, the demand patterns for the various hours in the day remained very similar over a 17-year period (high- and low-demand season). The summer profiles are still relative flat. Distinct peaks occur during morning and evening peak periods during the high demand season (winter).

3.5 Alignment of system peaks with TOU tariff peaks

Sent out data was analysed again to establish the growth in demand and to illustrate the data sent out in relation to the TOU peak periods. Figure 3-9 shows the demand profile on a Friday during Week 4 and Week 27 from 2005 to 2007. The TOU peak period is also indicated. During the low- and high-demand season (Week 4 and Week 27), the demand peaks almost at the end of the TOU morning peak period or just after it.

The system peaks in the high-demand season occur early in the evening TOU tariff period. It is also clear that demand generally increases substantially from around 17:00 during this season and remains high until the demand gradually drops from 20:00 to 20:40.

Figure 3-9 is based on actual sent out data and shows that the system peaks in the low-demand season occur late in the evening TOU tariff period. The demand increases from around 18:00 and starts to decline from around 20:45. Figure 3-9 shows that the TOU periods in both the morning and evening peaks are not long enough in duration to represent the demand on the system during this time. It is also clear that consumption peaks earlier in the high-demand season than in the low-demand season during the evening peak period.

Figure 3-9 further shows during the low-demand season of 2005 the demand in the TOU morning peak period was 27 770MW. The demand in 2007, for the same day and season was equal or more than 27 770MW from 07h00-22h00. During the high demand season of 2005 the demand in the TOU evening peak period was 32 799MW while the demand in 2007 during the same season was equal or more than this demand from 09h00-22h00. Both days during the high- and low demand season shows significant increases in demand from 2005 to 2007.

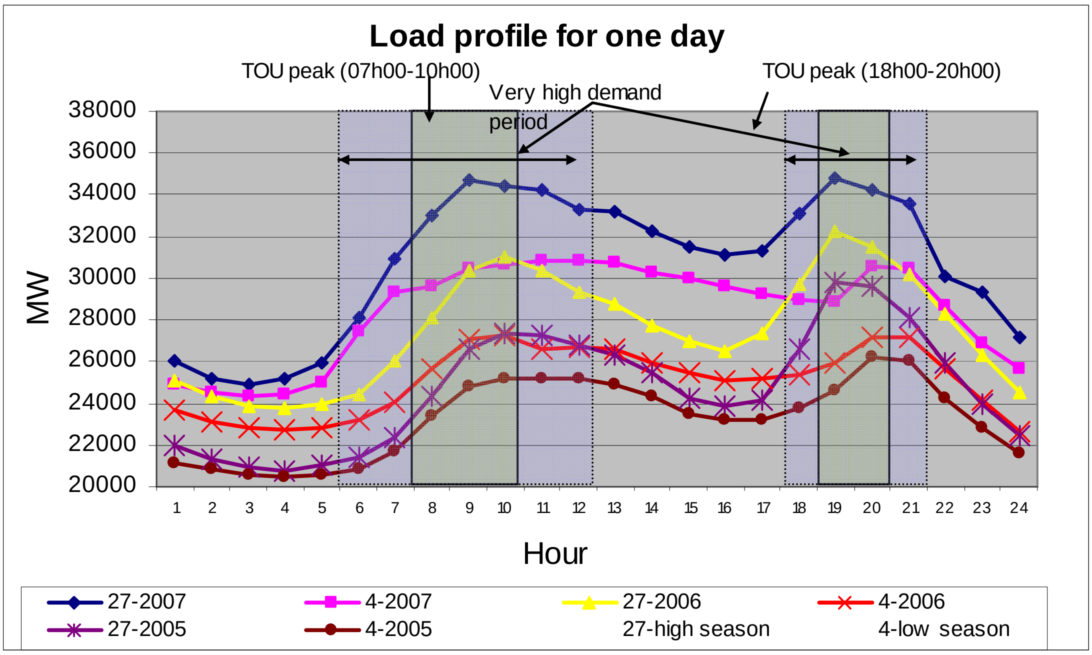

Figure 3-9: Load profile for one day during the high- and low-demand season (2005 to 2007)

3.5.1 Results

Although the consumption patterns remained constant over the past 17 years as shown in the previous section, the demand has increased substantially. This increase in peak demand must be supplied with the same generating capacity as in previous years (excluding recently installed peaking stations and DSM interventions). The consumption in standard periods is, therefore, equal to the consumption in TOU peak periods when the TOU tariff was initially introduced.

3.6 Conclusion

In some hours, it is more costly and more technically challenging for a utility to meet the demand than in others hours. However, customers base their decisions to shift load on pre-determined prices for specific hours of the day. Customers respond to or are able to respond to TOU tariffs. The individual responses are influenced by a number of factors. Two of the major influences in a customer's decision to respond is possibly financial and technical.

The analysis in this chapter proves that a number of customers ignore the TOU signal completely, while others may only respond if production patterns allow. The impression is that the financial incentive associated with the TOU tariff is generally not adequate enough to encourage a substantial load shift out of the TOU peak period. Although there has been a substantial increase in demand over the past few years, consumption patterns have not changed much during this time. Due to the growth in demand, more energy must be generated during all tariff periods when compared to historical data.

This analysis highlights one of the shortcomings of long run marginal cost (LRMC). The TOU tariff might have been an effective signal when it was designed and implemented initially, but its effectiveness has declined during the last few years. Due to the growth in demand, the peak demand periods of the past are now experienced during standard TOU tariff periods. In 2006, 28.71% of the electricity sent out by Eskom was higher than the highest recorded reading in 2000 (from figure 1-2). With the delay in capacity expansion, the TOU peak periods could possibly be expanded to motivate customers to change their consumption behaviour and consume more electricity during the TOU off-peak periods.

A huge contributor to the peaks is the residential customer, as explained in Chapter 1. It is a challenge to filter TOU pricing to residential customers. TOU metering is expensive and more complex to administer than conventional metering technologies. Another challenge is that most utilities have non-optimal price signals to encourage residential customers to respond to TOU tariffs. Promulgating new TOU tariff structures for residential customers is also a lengthy process and will, therefore, not lead to an immediate solution.

Tariff signals must become stronger to ensure that customers maintain DSM initiatives even after the five-year contractual obligation towards Eskom lapses. If tariff signals do not encourage customers to respond to the tariff, all DSM projects will deliver a MW shift/curtailment only for the contract period. It is possible that the investment could be worthless after the five-year contract period. This will reduce the effectiveness of the DSM process as the technologies installed to shift/curtail load are generally expected to last the lifetime of the equipment it controls. This period is generally between ten and twenty years.

The analysis highlights the fact that system peaks and tariff peaks are not exactly in line with each other due to the increase in demand over the past few years. In the next chapter, three load management initiatives will be investigated.

CHAPTER 4: ESKOM'S LOAD MANAGEMENT PROGRAMME

4.1 Introduction

Internationally, declining participation in demand side management (DSM) programmes can be attributed to the fact that customers incur significant upfront costs without the assurance of a benefit stream of payments [27]. Eskom implements a DSM programme where all upfront costs are funded as directed by the EEDSM policy [4]. Customers receive technologies that enable them to shift or curtail load at no cost.

In return, customers are expected to shift or curtail load out of the time of use (TOU) evening peak period (18:00 to 20:00) [4]. Customers' further benefit financially when energy is shifted or completely removed from peak periods.

Load management initiatives are contracted for a period of five years during the evening TOU peak period. In some cases, customers are also able to shift/curtail load out of the morning TOU peak period (07:00 to 10:00), and although the morning TOU period is not contracted, the financial incentive could encourage customers to shift/curtail load during this period.

The purpose of this chapter is to:

- quantify the load shift potential of selected load management initiatives;
- determine the advantages and disadvantages of selected load management initiatives;
- determine the success rate of various load management technologies; and
- highlight any shortcomings of load management.

4.2 Load management case studies

In order to illustrate the effect of load management projects and to prove that various technologies can shift/curtail load effectively, three examples of load shifting and one curtailment initiative are presented. The three load shifting technologies are hot-water load control as implemented in the residential sector, water pumping and hoist-winder initiatives as implemented in the mining sector. The curtailment initiative is compressed air management as implemented in the mining sector.

The examples presented in this section indicate the load shifted/curtailed out of the TOU peaks as required by the NERSA policy. The load shifting projects are mostly energy neutral, and load shifted out of TOU peak periods will be consumed during other TOU periods.

Curtailment initiatives are not energy neutral. The load removed will not be consumed during other times and is, therefore, completely removed from the power system. This chapter will not investigate the technical detail of the technologies, but will rather focus on how and if the technology can be used to optimise load management.

4.3 Residential hot water load control

Residential customers contribute approximately 17% of the total electricity consumption in South Africa [2]. The residential sector is also responsible for 35% of the maximum demand [2]. A residential hot water cylinder (HWC) – also referred to as a geyser – contributes substantially to this demand. The opportunity exists to switch a HWC off during peak periods without any discomfort to the customer. This is mainly due to the design of the HWC and its ability to store hot water.

Hot water load control is the only load management initiative currently implemented by Eskom in the residential sector. With RCR technology the forecasted load shift is determined by making use of the after diversity maximum demand (ADMD) [34]. HWCs can be controlled with RCRs or global system for mobile communications (GSM) technology. The potential MW shift will, however, remain the same, as only the technology switching the HWC changes. In this section, a project making use of RCRs to control the HWC was analysed.

The number of HWCs in South Africa that was controlled with radio/audio ripple control receivers (RCRs) at the turn of the century was estimated to be six hundred thousand [35]. The controllable load of the 600 000 HWCs was estimated to be 360MW [35] at the time, which indicates that a huge opportunity for load shifting initiatives with RCR technology still exists.

To implement an RCR initiative, energy metering, communication networks, central processing equipment and ripple or audio radio control receivers are installed. The RCR is switched on and off when it receives a pre-programmed signal from the control equipment. The RCRs are wired into the HWC circuits at a residential dwelling. RCRs allow current to flow to the HWC when it is switched on and, therefore, this presents the opportunity to perform load shifting. Data was collected at the substation level and the data was used to perform capacity and notch tests.

Capacity tests are performed to determine the number of HWCs that are controlled with RCRs from a specific point on an electrical network. During a capacity test, all controllable HWCs are switched off for a few hours from late evening to early morning. Due to the heat losses and the hot water consumed while the HWC is switched off, all HWCs should switch on when the RCR receives the pre-programmed signal to switch on. The total comeback load is measured and is divided by the average geyser size to indicate the amount of RCRs that are operational. The average geyser size generally ranges between 2kW and 4kW [36].

Notch tests are performed by switching the controllable HWCs off for five minutes and then on for 30 minutes over a period of a week. The resulting points in the measured data are calculated by taking an average of five minutes before and five minutes after the event during the TOU evening peak. The resulting points will indicate the maximum shiftable load that the system can achieve [37]. Research has shown that the load that can be shed per HWC in the morning is approximately 0.91kW to 0.84kW during autumn and winter respectively [35] and 0.62kW to 0.66kW during autumn and winter respectively [35].

With other DSM load management initiatives, baselines are developed before implementation. With residential hot water load control the notch and capacity test will determine the baseline which are done after commissioning of the system. The number of operational receivers, the after diversity maximum demand (ADMD) and the load shifted out of the evening TOU peak period were derived from the notch and capacity test and the results are presented in this section.

Figure 4-1 indicates the results of the capacity test that was performed on 9 July 2006. The average consumption while the HWCs were switched off was 11 496kW. When the RCRs were switched back on (allowing current to flow through), the consumption peaked at 25 873kW. The capacity of the HWCs that can be controlled with the RCRs from this municipal substation is therefore estimated at 14 377kW. By using the average geyser size of 2.67kW (calculated by Forlee) [35] as a guideline, it is estimated that 5 384 RCRs were operational when this capacity test was performed on 9 July 2006.

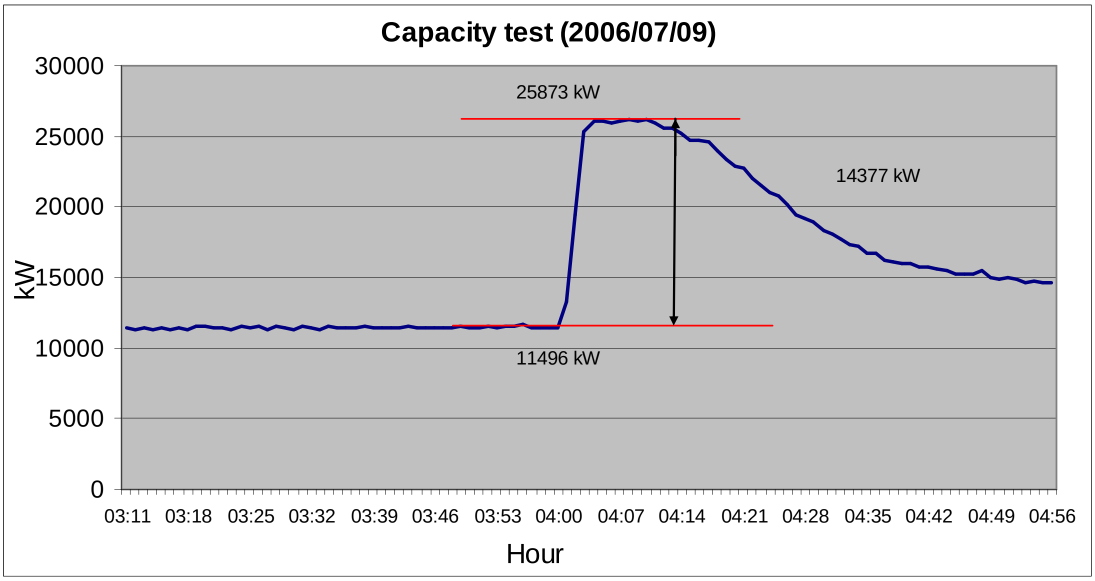

Figure 4-1 Cold pick-up indicating installed capacity of controlled HWCs

Data of a notch test performed on 8 September 2006 is presented in Figure 4-2. This test indicates a load shift potential of 2 419kW, 3 248kW, 2 857kW, 4 239kW and 5 114kW respectively during the TOU evening peak period. This load shift potential averages at 3575kW or 3.575MW between 18:00 and 20:00.

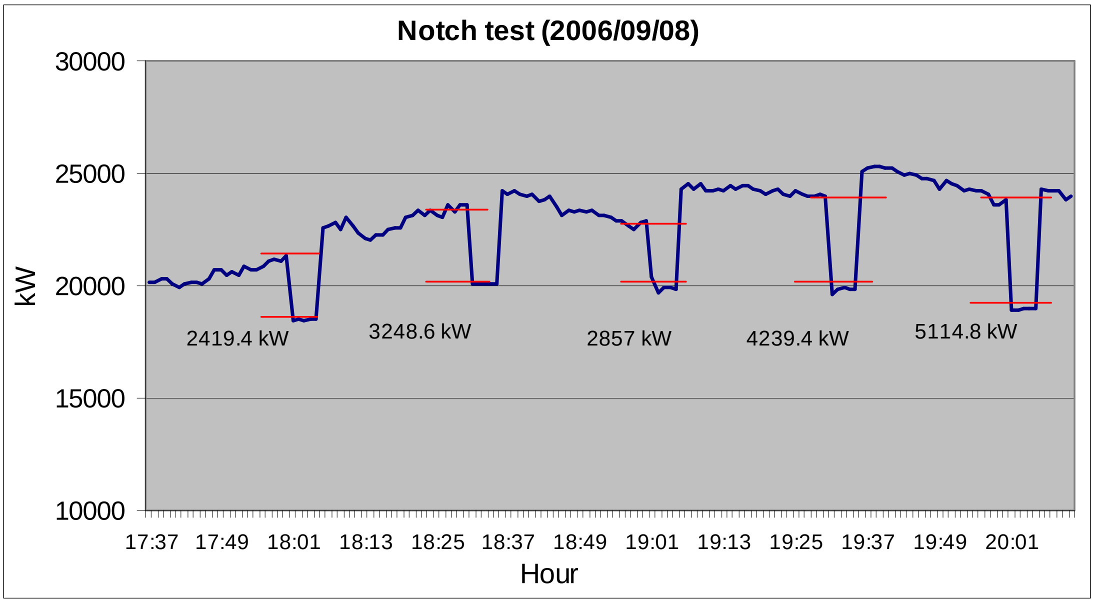

Figure 4-2: Notch test (8 September 2006)

Figure 4-2 further shows that the load shift potential varies every half an hour during the TOU evening peak as shown in Figure 4.2. This varying load shift potential can mainly be attributed to the consumption patterns of hot water from HWCs in residential areas. With hot water load control, the hot water consumption pattern differs between summer, autumn and winter months. The consumption patterns results in a different ADMD between seasons [37]. During the winter months, the consumption of hot water is much higher than that during summer months [37], [39]. It is therefore assumed that the controllable load will differ between seasons. Table 4-1 below shows the average seasonal ADMD calculated by Pandaram.

Table 4 -1: Average seasonal ADMD [37]

Season	Morning Peak ADMD (watts)	Evening Peak ADMD (watts)
Winter	1037.0	836.5
Autumn	762.9	705.3
Summer	552.4	429.4
Average	**784.1**	**657.1**

Potentially the highest load shift potential exists when the ADMD is at its highest and supports the assumption made that the controllable load will differ between seasons. However, most cold water complaints are experienced during the winter months. Over controlling during winter months could lead to illegal disconnections or a community not buying into these types of technologies.

Delport highlighted the fact that winter months don't necessarily translate in a bigger controllable load [39]. He further indicated that although hot water load increases in winter months, this increase don't necessarily allow for a bigger controllable load [39]. Thus a higher ADMD don't necessarily translate into a higher load shift as assumed earlier in this section.

With residential load management initiatives, the come back load is managed in a controlled manner by the various distributors. This is done in such a way as to not exceed their notified maximum demand. If the MD is not managed optimally it is possible that new peaks may be created in times outside TOU peak periods. This will mean high demand charges to distributors and Eskom will have to make access capacity available during these times.

4.3.1 Results

Residential hot water load control is effective in shifting load. The highest load shift potential exists during the TOU tariff peak periods due to residential hot water consumption patterns. Although this technology is effective in shifting load, the load shifted may create new system peaks if not managed optimally.

One major disadvantage of the RCR technology is that communication is unidirectional only. It is, therefore, impossible to know if a specific RCR is faulty or if the circuit has been bypassed unless a physical audit is done. Research done by Pandaram in 2008 indicate that of the audits done only 82% of the investments made in RCR technologies derived benefits for the Eskom network [37]. The same load shift will, however, be possible with GSM or smart meter technology. These technologies allow for two-way communication. Two-way communication allows for better control of residential hot water load control but these technologies come at higher capital and operational cost.

The research done by Forlee [35] shows that there is still huge opportunities for implementing residential hot water load control. It will be better to control a higher number of HWCs than to over control the existing HWCs. Over controlling of HWCs will lead to cold water complaints which could further lead to illegal disconnections.

4.4 Water pumping load control

A number of load shifting opportunities exist in pumping projects. These projects range from agricultural, mining and industrial projects to water supplying utilities. In all these projects, the load shift potential is directly related to the design and flexibility of operations. A number of factors contribute to the feasibility and sustainability of pumping projects, including the following:

- Minimum and maximum dam/reservoir capacity.
- Quantity of water pumped per day/month/season.
- Equipment constraints (size of pipes, pumps, electric motors, valves, etc.).
- Safety constraints (minimum requirement by customer and law).
- Maintenance constraints.
- Allowable on/off periods.
- Water usage/consumption.

In this specific case, an analysis of data was done in a mining environment. In a mining environment, water is used to cool down the underground working environment. In some cases, it is used during production activities and water collects naturally underground. All this water must be pumped out of the mine to prevent flooding.

Mining houses are under tremendous pressure to produce at maximum capacity and, therefore, load management technologies should not interfere with their production output. In order to do this, control and monitoring equipment are installed at delivery points. The information is sent back to a programmable logic controller (PLC) to ensure that the load management activities remain within the pre-programmed constraints.

Before implementing load management technologies, it is often impossible to switch the pumps on and off during the Eskom TOU tariff peak period. This is mainly due to mechanical stresses and the cost of labour and operational expenses. If manual load shifting is an option, the load shift possibility is normally much less than an intelligent optimised pumping system. Before this specific load shift technology was implemented, water was pumped at any time and no load shift was possible. Pump systems comprise of a series of pumps. Each pump station has pumps, valves, settlers, pipes and reservoirs.

In this water pumping example, there are four reservoirs at the surface and four underground at different levels. As soon as a reservoir below surface exceeds the pre-determined volume of water, the pumps will switch, on irrespective of the time of day. If the water is not pumped out of the mine, the mine or other mines in the area can flood, which can cause a mine to be closed down in some extreme cases. The pumps might switch on during the TOU tariff peak. This will lead to huge electrical accounts, which would not be the case if the pumps were controlled by optimised control equipment.

By optimising the system and installing the control equipment, the water can be pumped out of the reservoir in off-peak and standard TOU tariff periods. The correct dam levels can also be monitored on a supervisory control and data acquisition (SCADA) system. It will be possible to override the control equipment in cases of emergency, but under normal circumstances, this will be controlled by the control equipment to ensure a maximum load shift out of the tariff peak period.

The installation of DSM equipment allows for better monitoring and control of the operations. If this system is maintained, the mine will be able to participate for the contracted five-year period. After the contract period, the mine should also be able to shift load for the life span of the equipment if the tariff signal is sufficient.

Measured metering data was analysed to determine the exact impact of this pumping initiative. The baseline data, as agreed to between the ESCo, client (mine), Eskom DSM and the independent M&V entity, was compared to the actual metering data measured after implementation. The TOU peak tariff periods are also indicated.

Figure 4-3 represents the baseline (before) and after implementation load profile. During the morning and evening TOU tariff period, 5.685MW and 11.588MW was respectively shifted out of the tariff peak periods. More energy was, therefore, consumed in the off-peak and standard TOU tariff periods. There was an increase in demand of 5.062MW and 10.456MW respectively between 12:00 and 17:00 and between 20:00 and 22:00 on the day of the analysis.

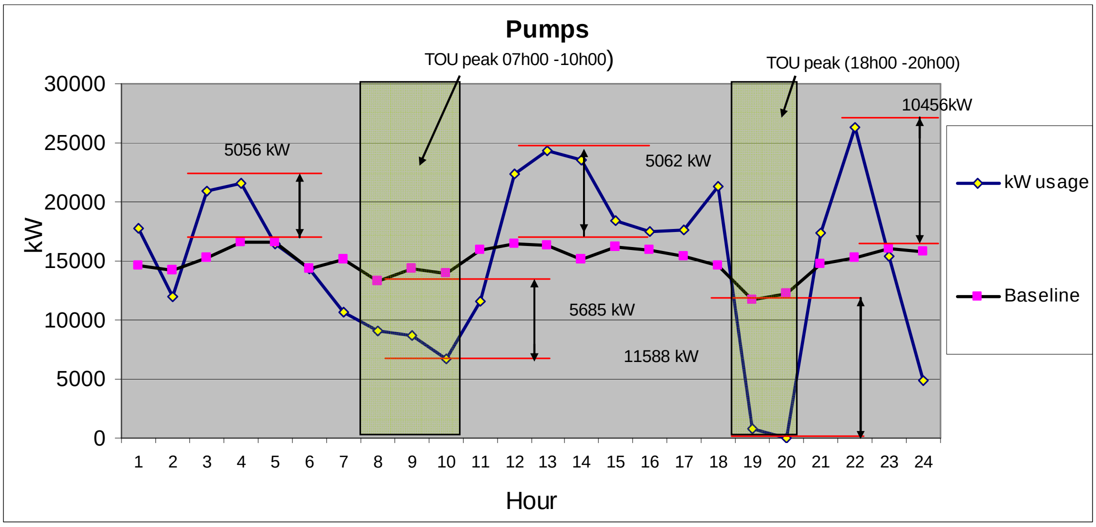

Figure 4-3: Load shifting (mining pumping initiative)

4.4.1 Results

Pumping initiatives in mining environments can shift load effectively. Due to storage capacity at this mine, load shifting can be achieved at any time of the day. The reason this initiative is shifting load during the TOU tariff peak is due to contractual obligations and the monetary savings to customers. Due to the load shift, the demand in the periods after the TOU peak periods is higher than the baseline.

4.5 Winders load control

Winding systems at mines are either used for the extraction of ore (rock winders) or to transport workers and equipment (man winders) between the various shafts. The combined consumption of winders contributes substantially to a mine's total electricity consumption. It is difficult to implement load management initiatives on man winders due to the human factor and mining operations. Man winders do not consume large amounts of electrical energy and, therefore, load management technologies on man winders have not been implemented through the Energy

Efficiency and Demand Side Management (EEDSM) Fund to date.

Rock winders, on the other hand, consume substantial amounts of electrical energy, and are not affected by the human factor. Load shifting is possible with the installation of basic control equipment. Before this load management initiative was implemented, ore was extracted with the winders 24 hours a day, seven days a week. As soon as the skip is fully loaded, the winders automatically hoist the skip to the surface where it is emptied.

A control system comprising SCADA and PLCs are installed and the control system is programmed to prevent rock winders from operating simultaneously in the TOU peak periods. Ore extraction will, therefore, continue during the TOU peak periods, but will be limited to ensure that the production processes are not affected. The control system of the rock winders is set up to ensure that the safety and production requirements of the mine are not affected.

Measured metering data was analysed to determine the exact impact of this winders initiative. The baseline data, as agreed to between the ESCo, client (mine), Eskom DSM and the independent M&V entity, was compared to the actual metering data measured after implementation. The TOU peak tariff periods are also indicated. Although the installed capacity of the winders is much higher, the contracted load shift on this initiative is only 3MW.

The reason for only contracting 3MW is to allow some rock winders to continue operating during the evening peak period. This ensures that the mine produces at maximum capacity, while saving through the TOU tariff, and that the mine complies with its contractual obligations in the DSM agreement between the mine and Eskom.

Figure 4-4 represents the baseline (before) and after implementation load profile. During the morning and evening TOU tariff period, 1.055MW and 3.15MW was respectively shifted out of the tariff peak periods. More energy was, therefore, consumed in the off-peak and standard TOU tariff periods. There was an increase in demand of 1.425MW and 1.438MW respectively between 12:00 and 14:00 and between 22:00-24:00 on the day of the analysis.

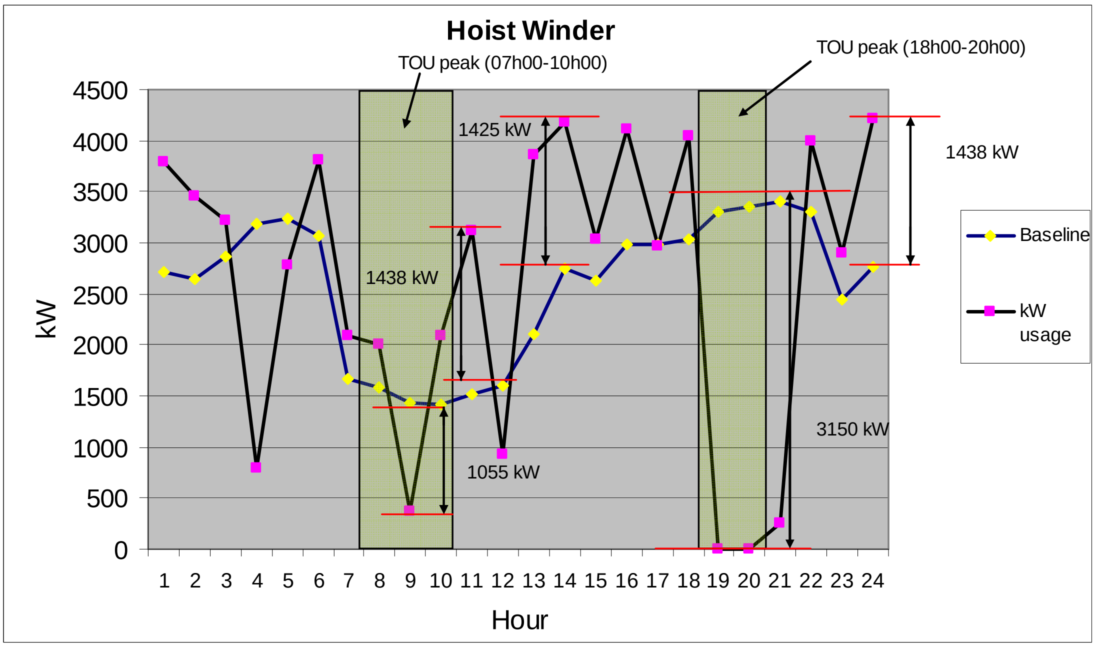

Figure 4-4: Load shifting (mining winder initiative)

4.5.1 Results

Winder initiatives in mining environments can shift load effectively. Due to flexibility around production processes at this mine, load shifting can be achieved at any time during the day. The reason this initiative is shifting load during the TOU tariff peak is due to contractual obligations and the monetary savings to the customers. Due to the load shift, the demand in the periods after the TOU peak periods is higher than the baseline.

4.6 Compressed air management

Compressed air systems at mines are used for drilling, operation of pneumatic equipment, agitation, cooling etc. Compressed air rings normally consist of a number of users such as mine shafts and metallurgical plants. The ring is usually supplied from a number of compressors situated along the ring. Mining companies are reluctant to implement compressed air initiatives due to the possible interference with production.

By installing dynamic compressed air simulation, monitoring and control system technologies, load can be curtailed from the system during TOU peak periods as defined by the EEDSM policy [4]. These dynamic simulation, monitoring and control systems take into account all relevant safety, health, operational and other constraints. This ensures that optimal air pressure and flow is available at all locations in the network during the TOU peak periods.

Figure 4-5 represents the baseline (before) and the after implementation load profile of a typical day for a compressed air initiative. Measured metering data was analysed to determine the exact impact of this compressed air management initiative. The baseline data, as agreed to between the ESCo, client (mine), Eskom DSM and the independent M&V entity, was compared to the actual metering data measured after implementation. The TOU peak tariff periods are also indicated. This compressed air initiative lead to a total curtailment of 4.403MW and 7.724MW respectively out of the TOU morning and evening peak period.

Although this is a curtailment initiative, a huge energy efficient component is realised as a result of the newly installed technologies. By controlling the angle of the air inlet vanes (guide vanes), inlet air flow is reduced to the minimum required amount. This ensures that the supply of compressed air meets the demand and no compressed air is wasted. This avoids pressures rising to high, with possible additional wastage due to blow-off to atmosphere. By making use of this compressed air technology, energy consumption of 2.849MWh and 2.769MWh were avoided during December 2008 and January 2009 respectively.

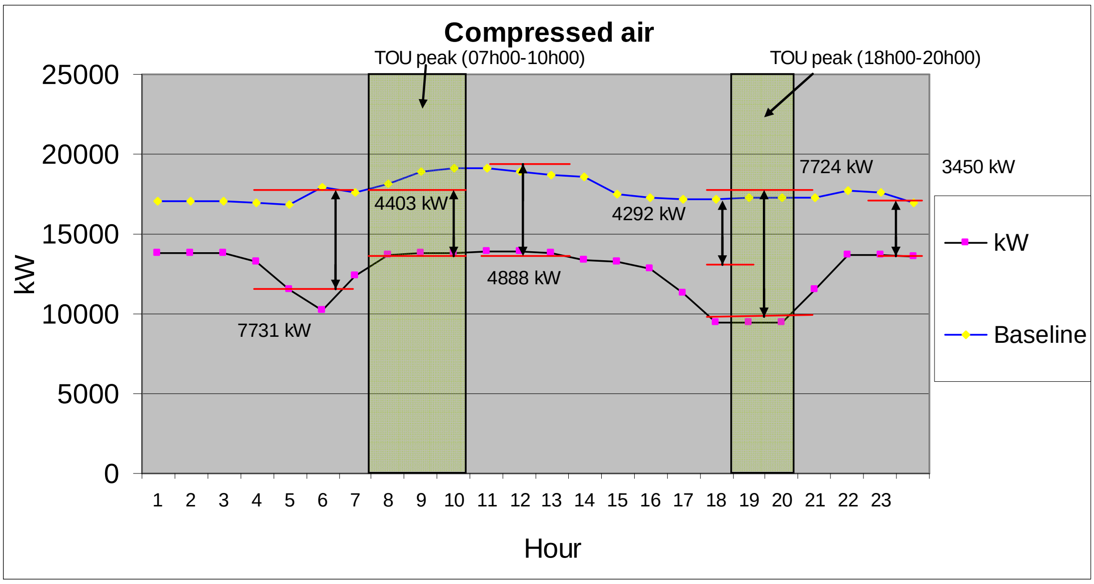

Figure 4-5: Load curtailment (mining compressed air initiative)

4.6.1 Results

From all the load management initiatives that were investigated in this section, this technology is by far the most effective. This is because no come- back load is experienced. Due to production processes at the particular mine and the flexibility of the technology, a huge energy efficient component is also realised as part of the initiative. The energy efficient component is evident in Figure 4-5 and although this relates to reduced energy sales, it achieves government's objectives by reducing the national demand profile. It seems as if a national roll-out of these technologies on all mining sites should be investigated.

4.7 Performance of load management initiatives

Eskom is obliged to ensure that EEDSM programmes are implemented as specified by the EEDSM policy [4]. The performance of all projects funded thought the EEDSM Fund must be measured and verified by an independent body. This body is known as an M&V entity and is accountable to provide NERSA, Eskom DSM, the client and the ESCo with credible independent reports. These reports quantify and assess project performance, the number of projects and MW shifted/curtailed through load management initiatives or saved through energy efficiency [4]. The reports also verify if initiatives are being sustained.

Before any Eskom DSM initiative can be implemented, a baseline must be determined. To develop a baseline, the M&V team will conduct measurements for a predetermined time (dictated by the type of technology). This data will be used and a baseline will be developed. The ESCo, M&V team and Eskom DSM must agree to a baseline before a project can be implemented.

A condonable day is a day when an ESCo or a client cannot meet contracted load shift/curtailment or energy efficient targets due to factors beyond the control of the ESCo or the client. Condonable days will vary for the different customer groups and performance on condonable days will not affect the performance of any DSM intervention if Eskom declares the day a condonable day.

All M&V reports are available to Eskom DSM once they have been captured on the server. The half -hour data is not readily available and each M&V report reflects the average load shift obtained during a specific month. The exact impact of load management initiatives at any given time is not available to Eskom DSM.

Performance reports may only be available one month after they have been developed. No real-time tracking system currently exists for DSM projects. In order to establish the performance of load management initiatives, all available M&V reports for completed load management initiatives were reviewed. These results are captured in Figure 4-6. The results represent completed load management initiatives from the establishment of Eskom DSM to March 2008.

The MW reduction reported on in the M&V reports represents an average monthly load shift/curtailment during evening peak periods, unless a load shift/curtailment in the morning was also agreed between the relevant parties. For purposes of confidentiality, various technologies were grouped and are represented as Technology 1 to Technology 8.

M&V reports were analysed and the average monthly load shift/curtailment was recorded per technology. Figure 4-6 shows the performance of different load management technologies for which data was available up to March 2008. The performance of the different initiatives ranges from 44.69% to 110%, with an average performance of 82%.

These results show that certain load management initiatives perform better than others. Performance of technologies and ESCos were still a very uncertain topic when DSM started. Eskom DSM is now in a better position to evaluate project proposals, as the performance of technologies and ESCos are known.

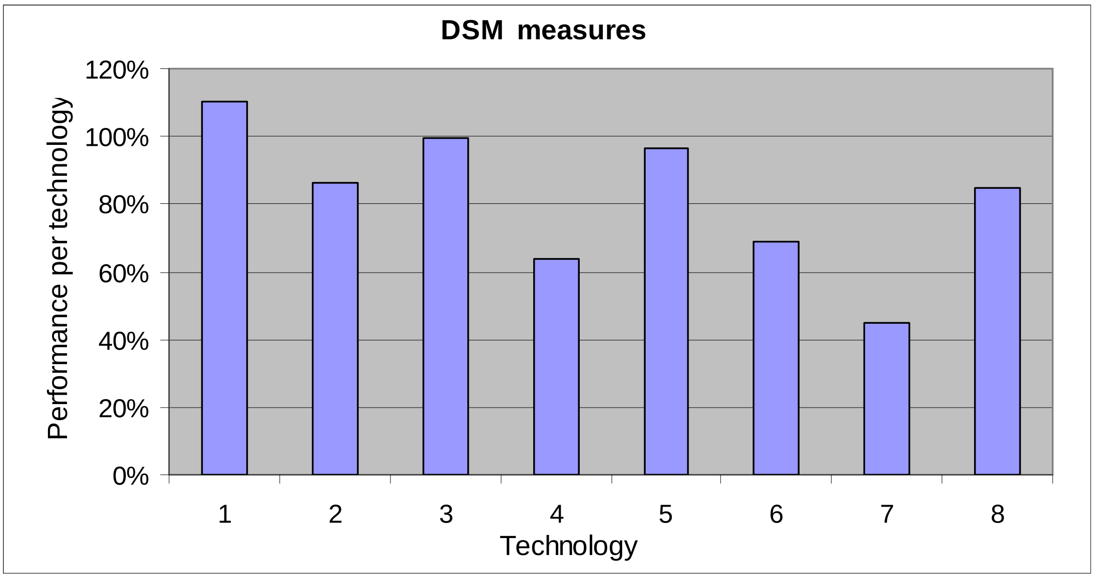

Figure 4-6: Performance of load management measures

The actual verified MW shift obtained by Eskom DSM during 2006/2007 was 103.6MW [38]. This is higher than the 90MW required by the EEDSM regulatory policy for residential, industrial and mining load management [4].

4.6.1 Results

Certain load management initiatives perform better than others and it is possible to establish trends for the various initiatives. It is currently not possible to establish the real-time impact of load management initiatives on the power system due to unavailability of metering data.

4.8 Conclusion

The analysis of the residential HWC project indicated that a different load shift potential exists during the morning and evening peak periods. The controllable load of a HWC also changes per season and the maximum controllable load is in the high-demand season (winter). If residential hot water load control is not managed optimally, it may lead to new peaks and cold water complaints which could further result in illegal disconnections.

The analysis of the underground pumping and winder initiatives proved that these types of technologies can shift load effectively. The two load shifting technologies investigated in the mining environment can further shift load during any hour of the day. The reason for shifting load out of the TOU evening peak period is because of the NERSA regulatory policy.

All three load shift initiatives covered in this section shows come back load after TOU peak periods. This come back load have effects on the system and can create new peaks. The come back load will have to be managed to avoid the creation of new peaks. It is extremely difficult to manage come back load and the only way this can be managed from a suppliers perspective is to implement heavy penalties to customers that exceed their notified maximum demand. Further if all customers simply shifts load, new peaks will be created. A balance is therefore required between load curtailment, load shifting and energy efficient initiatives to ensure an optimal load profile.

The analysis of the compressed air initiative proved that this technology can curtail load effectively. No come back load is experienced and this initiative also proved to have an effective energy efficient component associated with it.

The data gathering and analysis of M&V reports are a huge and time-consuming process. Only a monthly average load shift is available in the published M&V reports. It is imperative that half-hour data must be made available to Eskom DSM for all load management initiatives. It is impossible to establish the full impact of load management if actual metering data is not readily available.

With proper analysis and a more flexible regulatory policy, Eskom clients might be able to shift/curtail load during other times when constraints are being experienced and not only during

TOU peak periods. All DSM initiatives come at a cost to the economy as these initiatives are funded through levies imposed on all customers of electricity.

The advantages specific to DSM initiatives are as follows:

- A number of DSM initiatives can shift/curtail load effectively without affecting production or consumption patterns.
- Communication and control equipment are installed with each DSM initiative. These technologies will allow for a more dynamic approach if allowed.
- Compressed air curtailment initiatives have a huge energy efficiency component associated with the technology

The disadvantages specific to load management initiatives are as follow:

- The response is fixed and not flexible.
- Customers might shift load when access capacity is available.
- Customers might shift load to times when constraints will be experienced.
- Customers may be creating new peaks.
- Eskom funds these initiatives and underperformance of the initiatives will reduce the value of the investment.

Fixed responses declined internationally and more emphasis should be placed on active/dynamic DSM initiatives.

CHAPTER 5: MANAGING PEAK DEMAND USING DMP

5.1 Introduction

According to Prof Anton Eberhard, the demand market participation (DMP) programme that was implemented during the Cape crisis, was probably the most successful of all demand side management (DSM) initiatives [18]. The DMP programme initiated in the Western Cape proved to yield over 100MW by May 2006. A major contributor to the success of the DMP programme during this crisis in 2006 was most likely due to the short implementation period required for DMP.

The purpose of this chapter is to:

- determine the advantages and disadvantages of DMP;
- quantify the load curtailment potential during selected DMP events; and
- establish if DMP is used more often during specific hours or seasons.

The results of the analysis in this chapter will demonstrate if DMP is effective in reducing demand during times of constraints and the times of day when DMP is mostly used.

5.2 Expected DMP responses

For the analysis in this section, the system operator's event list for 2007 was analysed. This event list indicates the date, time, duration and quantity of the expected MW reduction for DMP events for the whole of 2007. The system operator compiles the event list based on day-ahead estimates. Customers are only requested to curtail load when constraints are anticipated at any given hour. The event list is based on the quantity of MW customers were requested to curtail. The event list does not represent what was actually curtailed on a specific day. Although the expected and actual MW curtailments could differ, the difference is normally not substantial. The reasons for this are as follows:

- Customers are compensated for actual performance and Eskom never pays for underperformance on the DMP programme.
- Continued under-performance by a customer may lead to the cancellation of a DMP contract.

The actual customer response is calculated after the expected event and settling of accounts occurs monthly. All expected responses from the system operator's event list were grouped and categorised. The following results were derived from the analysis:

- The expected MW curtailment for each hour (average per month) for both the high- and low-demand season.
- Average expected response per month.
- Expected responses during the time of use (TOU) tariff periods.

Figure 5-1 illustrates the expected DMP responses per hour as an average for the year, as well as an average for the high- and low-demand season. It is clear that the highest expected response occurred out of the TOU tariff period (17:00). It further shows expected responses for all the hours between 05:00 and 20h00. The average responses are not very high, except for 17:00 and 18:00.

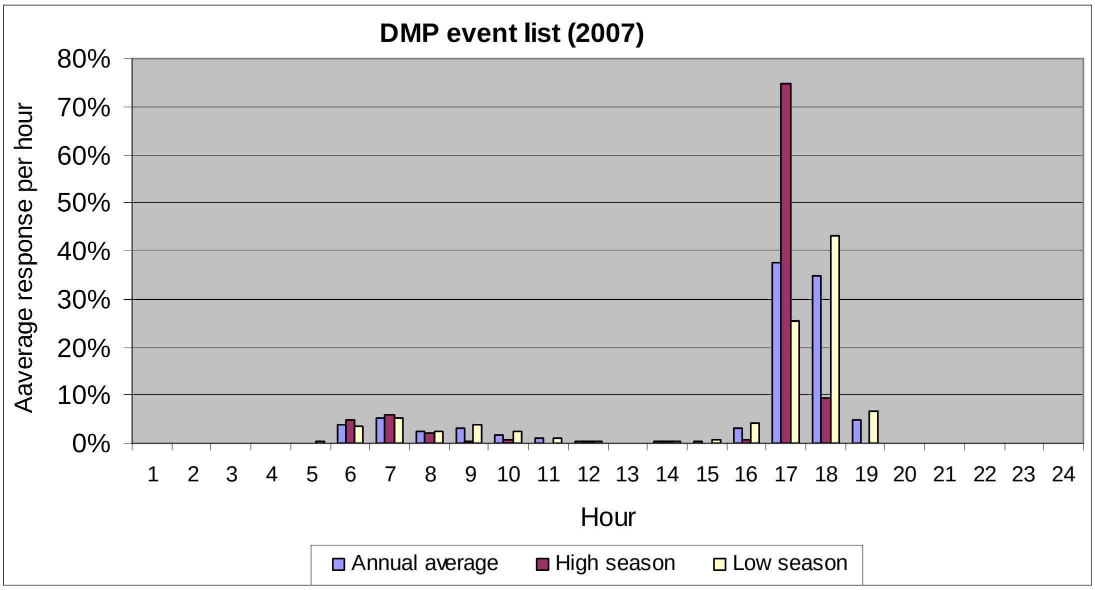

Figure 5-1: DMP event list (2007) indicating expected events per hour

Table 5-1 shows the year, as well as an average response during the high- and low-demand season. On average, the expected curtailments during the peak and standard TOU periods were relatively equal with a limited response required during the off-peak period.

Table 5-1 further shows the expected responses during the high-demand and low-demand season. The expected responses during the TOU tariff peak period were approximately three times higher in the low-demand season than in the high-demand season.

The expected responses during the TOU tariff standard period were approximately twice as high in the high-demand season than in the low-demand season. These expected responses indicate constraints during these times and correlate with the system sent out information presented in Chapter 3. This can be attributed to the relative low tariffs during the TOU peak period (low-demand season) and TOU standard period (high-demand season).

Table 5-1: Expected DMP responses (presented according to the TOU tariff)

	Average	**High-demand season**	**Low-demand season**
Peak	50.48 %	17.83 %	61.36 %
Standard	49.26%	82.05%	38.33%
Off-peak	0.26 %	0.12 %	0.31 %

Figure 5-2 shows the average expected DMP responses per month. The expected responses between October and December 2007 are much higher than those for the rest of the year and once again fall within the TOU low-demand season. The higher expected response during this time might be attributed to routine maintenance on the generation plant.

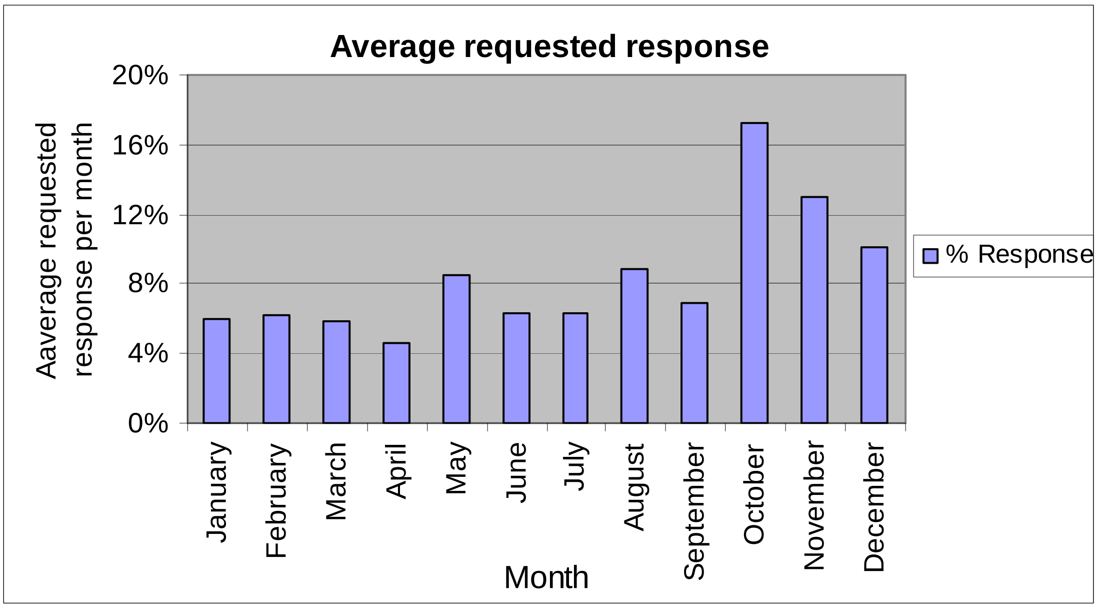

Figure 5-2: Average requested response (grouped per month)

Figure 5-3 shows the average expected response for October 2007. The X-axis represents the hour of the day and the Y-axis represents the average expected response per hour. It is noticeable how the expected curtailment increases when system peaks are experienced. This highlights the flexibility of DMP and the possibility to curtail load at any hour, based on a day-ahead notice period.

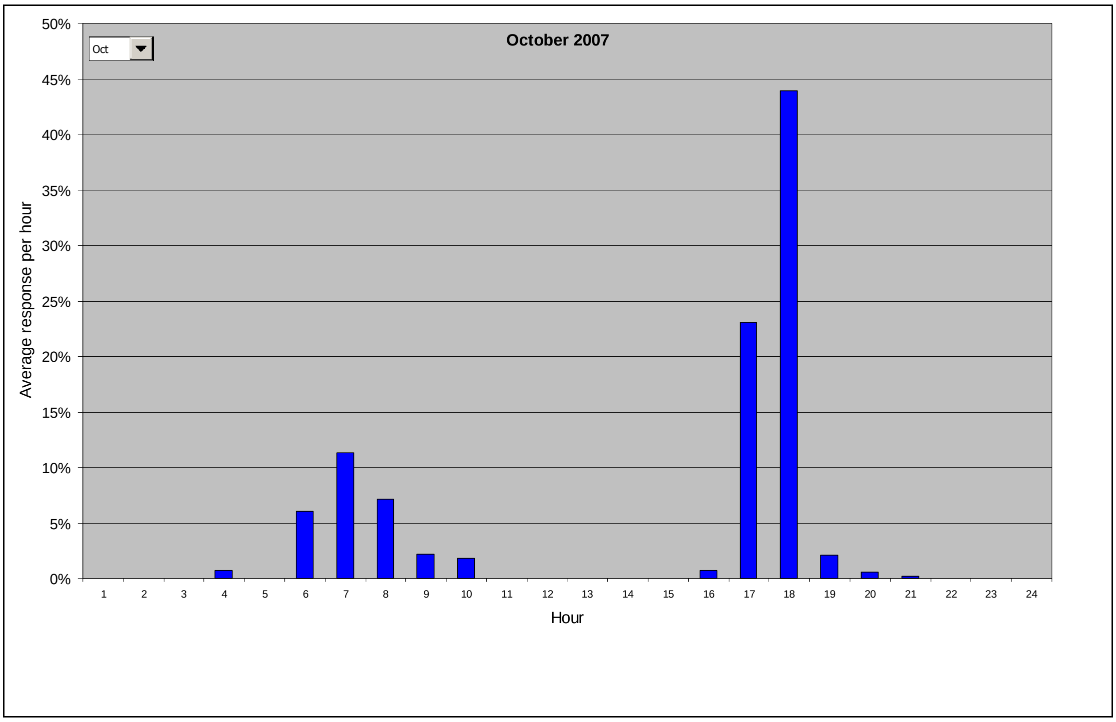

Figure 5-3: Expected average DMP responses for October 2007

5.2.1 Results

A substantial DMP response is expected during the standard TOU period. The DMP responses emphasises the need for a more effective tariff signal. Due to the flexibility of DMP, actual system constraints can be managed more effectively than with a static programme such as load management.

5.3. Actual DMP responses during a curtailment event

In this section, actual DMP responses will be investigated. Metering data was collected of DMP customers. Due to the higher than average responses during October (figure 5-2), 13 October 2007 was selected. The data was analysed and is represented in Figure 5-4. Figure 5-4 shows the actual response of nine customer groups on 13 October 2007. The y-axis represents the MW reduction achieved by each customer, while the x-axis represents the hour of the day.

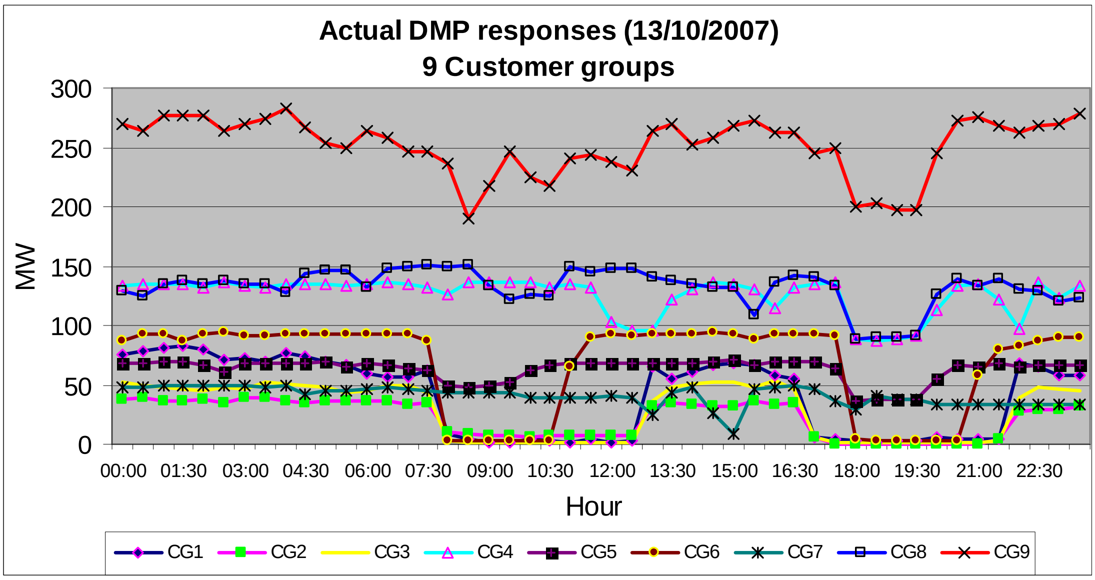

Figure 5-4: Actual DMP responses on 13 October 2007

Table 5-2 shows the actual responses on 13 October 2007. The total response for the day was 683MW from the customers indicated below. The response ranged between 08:00 and 21:00 and can be categorised according to the following time slots: 08:00 to 11:00 – 249MW, 11:00 to 13:00 – 165MW, 18:00 to 20:00 – 269MW and 20:00 to 21:00 – 84MW.

Table 5-2: Actual DMP responses on 13 October 2007

Customer Group	Expected MW Response	Time of response
1 to 3	165	08:00 – 13:00
1 to 3	165	17:00 – 22:00
4	40	18:00 – 20:00
5	30	18:00 – 20:00
6	84	08:00 – 11:00
6	84	18:00 – 21:00
7	10	18:00 – 20:00
8	45	18:00 – 20:00
9	60	18:00 – 20:00

Figure 5-5 illustrates the combined effect of a number of smaller DMP participants on 4 June 2007. Nine customers participated in this event. The total MW required from these customers was 10MW between 17:30 and 19:30. Figure 5-5 illustrates that a number of smaller customers can make a valuable contribution to DMP and that the technologies are in place to accommodate multiple participation in DMP initiatives.

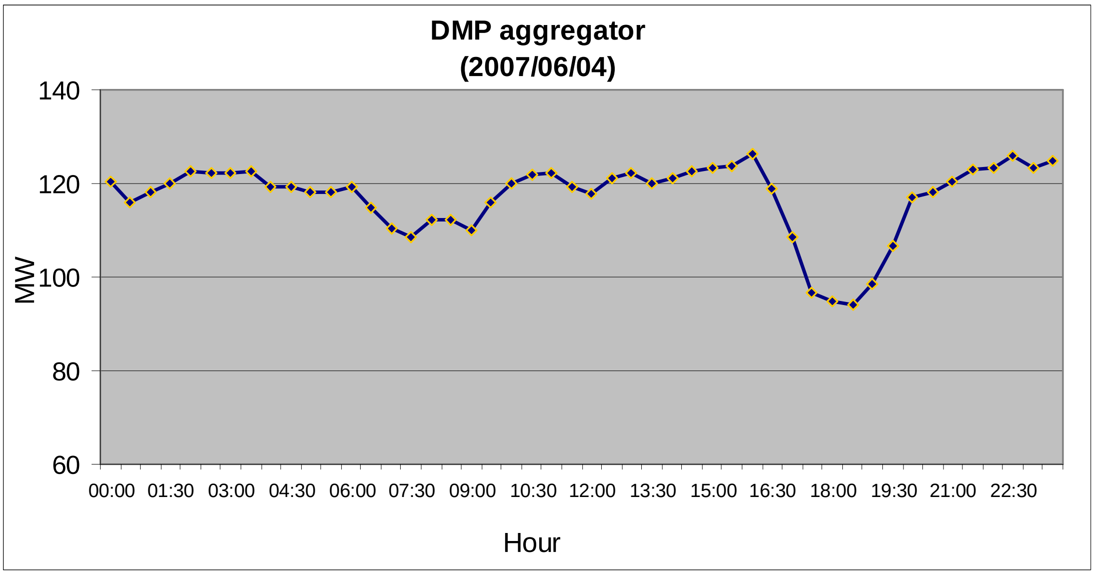

Figure 5-5: Combination of smaller DMP participants

5.3.1 Results

DMP is effective in curtailing load at any time when Eskom experiences constraints on the networks. DMP, therefore, has the ability to assist the system operator to ensure adequate capacity and that reserves are on line for each hour of the day.

5.4. Further benefits of DMP

To a certain extent, load management and emergency/supplemental DMP can be counted among planned reserves and, as such, become part of the overall resources assembled to meet the system reserve margin [6].

Instantaneous DMP provides benefits distinct from load shifting and emergency/supplemental DMP. Instantaneous DMP provides incremental reliability benefits, of which one is under-frequency response. The extent of each response is determined by the specific need. Eskom's DMP customers responding in the instantaneous reserve category are automatically switched off by a control circuit at 49.65Hz (previously this category responded at 49.75Hz). The supply to the participating customers is then automatically restored when the frequency reaches 49.85Hz.

Data was collected for a number of under-frequency events that occurred during 2006 and 2007. The data analysed in this section represents a good example of a typical under-frequency event.

Figure 5-6 represents the total instantaneous DMP response on 10 July 2007 between 17:47:54 and 17:57:20. The response shown is a graphic representation of the four customers who responded during this event. Once again, customer names are withheld and the customers have been grouped from Customer A to Customer D.

The total combined response during the event was 124.37MW. The combined load before the event was 240.75MW and this dropped to a combined load of 116.39MW during the event. Customer A to D's individual responses were 55.39, 24.42, 10.35 and 34.2MWs respectively. It is clear that as soon as the frequency dropped at around 17:47:54, the individual customer load was reduced. At 17:57:22, the frequency stabilised and, as the frequency increased above 49.85Hz, the individual loads increased again, except for Customer C who did not increase load immediately.

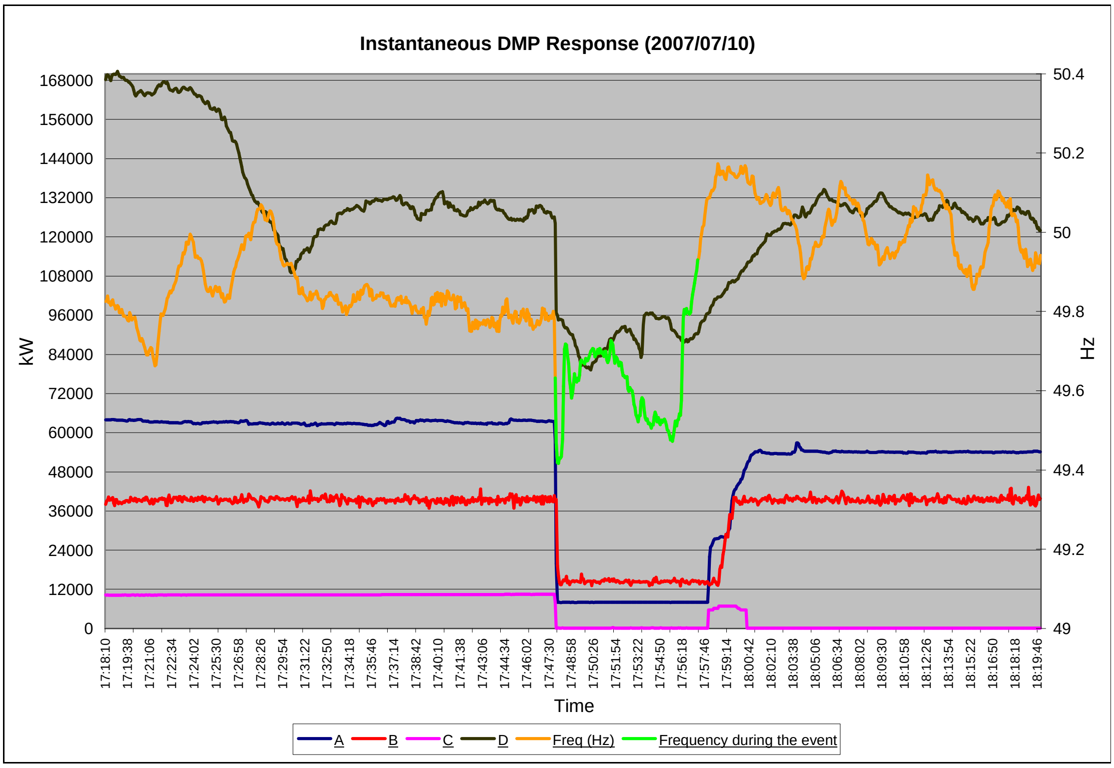

Figure 5-6: Instantaneous DMP response for 10 July 2007

Customer C consumed 10.5MW before the event and the load was only restored a few minutes later. It is possible that the delay in the increase of the load might be due to a delay in production processes coming on line again. Table 5-3 shows the individual customers' responses and the MW reductions during the event.

Table 5-3: Customer response (under-frequency event)

Customer	**Before event**	**During event**
Customer A	63.42MW	55.392MW
Customer B	40.7MW	24.417MW
Customer C	10.5MW	10.355MW
Customer D	126.13MW	34.203MW
Total	**240.75MW**	**124.367MW**

5.4.1 Results

Instantaneous DMP is effective in assisting with under-frequency events. The response is immediate with no delays. In order for a customer to respond to instantaneous DMP as currently implemented, the following is required:

- Metering and control equipment must be in place to enable an automatic response.
- The quantity of MW a customer can respond by must be substantial enough to make a meaningful contribution.
- The customer's production processes must allow for an immediate shutdown of a certain part of the plant.

5.5 Conclusion

Emergency/supplemental DMP can be counted among planned reserves and, as such, become part of the overall resources available to meet the system reserve margin [6]. This is possible because the system operator is able to request DMP customers to curtail load on a day-ahead basis.

DMP is, therefore, flexible and can be dispatched when required and the customer can continue with their normal processes if no constraints are experienced. DMP comes at a cost to the economy as it is very costly to dispatch.

DMP can be used effectively to manage and correct under-frequency events. With DMP, a substantial number of MWs can be removed from the system in a very short space of time. Customers that respond to under-frequency events need to have control equipment in place that will enable them to respond if required. The individual customer's production processes must, however, allow for an unexpected response. A relative constant consumption pattern allows for easier settling of accounts as this is used in the baseline determination. However, it is possible to agree to a fair baseline with almost any customer. The advantages specific to DMP are as follows:

- DMP is flexible and can respond when constraints are expected or experienced on the power system.
- Customers are only paid for their response (except with instantaneous DMP).
- Customers are not expected to curtail load when access capacity is available.
- Customers have a better understanding of system constraints because they communicate with the system operator to submit their curtailment bids.
- There is a lesser chance of being switched off during load shedding if the customer participates in the DMP programme.

The disadvantages specific to DMP are as follows:

- DMP has limited participants.
- DMP is an expensive option due to limited participation and the lack of competition.
- DMP may not be sustainable on the long run if customers are called on to respond too often and customer fatigue occurs.
- DMP is costly.

CHAPTER 6: OPTIMISATION OF DSM PRACTICES

6.1 Introduction

In the previous chapters, load management and demand market participation (DMP) were investigated. DMP proved to be flexible and effective in achieving a desired objective. Load management initiatives also proved to deliver a desired quantity of MWs. However, due to load management consisting of load shifting, as well as curtailment initiatives, the effect on the network will differ. Load management initiatives further proved not to be as flexible and effective as the case with DMP. The purpose of this chapter is therefore to establish:

- if load management initiatives can become more dynamic (able to be dispatched based on system constraints, as with DMP);
- if DMP and load management will be required in future; and
- possible tariff options that ensure an optimal signal to encourage customers to shift/curtail load effectively.

6.2 Load predictions based on historical data

The purpose of this section is to establish the capacity that will be available to meet the demand in the short term and the associated role load management and DMP may play in meeting this demand. The average load profile for summer (low-demand season) and winter (high- demand season) during 2006 was used as a baseline. New generation capacity coming on line from 2008 to 2015 [7], [41] was included in the total generation capacity for each year. The published quantity [7], [41] of new capacity coming on line was used. This might change due to delays, fast-tracked generation investments and changes to capacity expansion plans.

A basic toolkit was developed and this was used to filter information. The toolkit factored in the average load expected for each season from 2008 to 2016 at a growth rate of between 0 and 8%. The toolkit also included the percentage of generation capacity available for the specific season. The expected growth in electricity consumption was assumed to be 2.5% per annum and, therefore, this was used in the illustrations below. Commissioning dates of new generation plant were used and this is, therefore, only a high level estimation of the capacity that will be available.

During the winter season, the available capacity is generally at its highest. The available capacity during the summer season is generally lower during this time, due to the routine maintenance taking place during the summer season. For this reason, an availability of 93% of total installed capacity was selected in the winter season and an availability of 84% was selected during the summer season for the purpose of this illustration.

The percentage of unavailability includes provisions for reserves, as well as planned maintenance. Unplanned maintenance is not factored in. The capacity represents the maximum available capacity for the whole day. Some of this will not be available for 24 hours of the day because of the associated technology (pumped storage and gas turbines). The line representing the capacity (yellow) will, therefore, not be parallel to the x-axis at all times. However, for this illustration, the capacity will remain constant (at maximum) for the whole period.

Figure 6-1 illustrates an average summer profile for 2006 and 2011. The data for 2006 is the actual average summer profile and the data for 2011 is an assumption based on a growth of 2.5% per annum from 2006 to 2011. The yellow line represents 84% of the installed capacity in 2011. Figure 6-1 shows the difference between the load profile and the maximum available supply is not much (1285MW for Monday during the TOU evening period). The maximum capacity will also not be at this level throughout each day and will differ daily. A growth rate of 2.5% per annum is also not high and if the worldwide economy regains the growth we seen until late in 2008, the evening peak will exceed the available supply (1583MW at a growth rate of 4%).

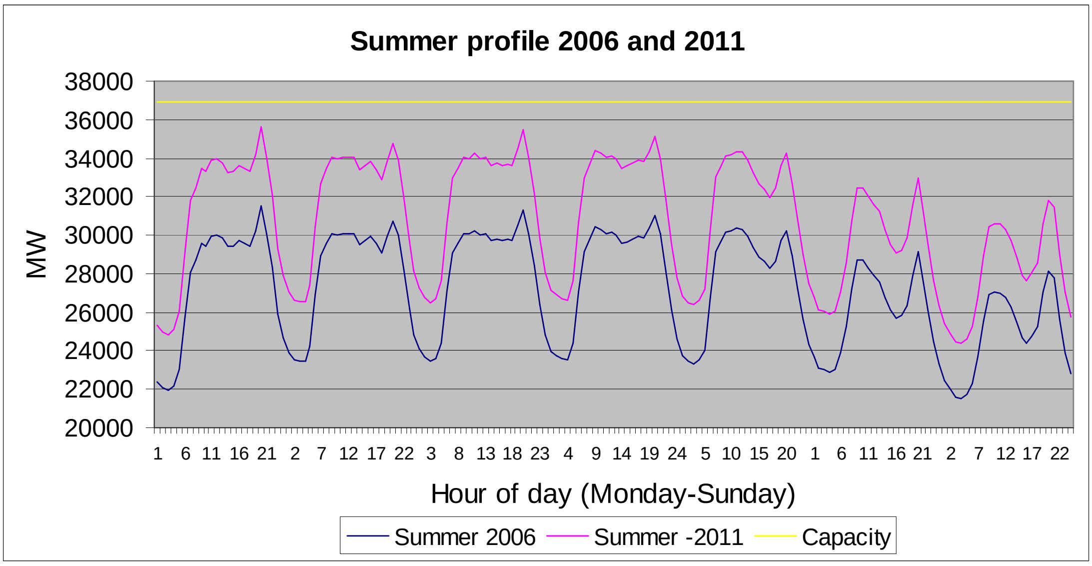

Figure 6-1 Average profile (Summer2006 and 2011)

Figure 6-2 illustrates an average summer profile for 2006 and 2014. The data for 2006 is the actual average summer profile and the data for 2014 is an assumption based on a growth of 2.5% per annum from 2006 to 2014. The yellow line represents 84% of the installed capacity in 2014. Figure 6-2 shows that adequate capacity will be available for the supply to meet the demand after 2014 if the growth rate remains between 0 and 4%. If the growth rate increases to 4.5%, the demand during the evening peak period will be equal to the available capacity (taken at 4.5% growth rate per annum with 84 % capacity availability for 2014).

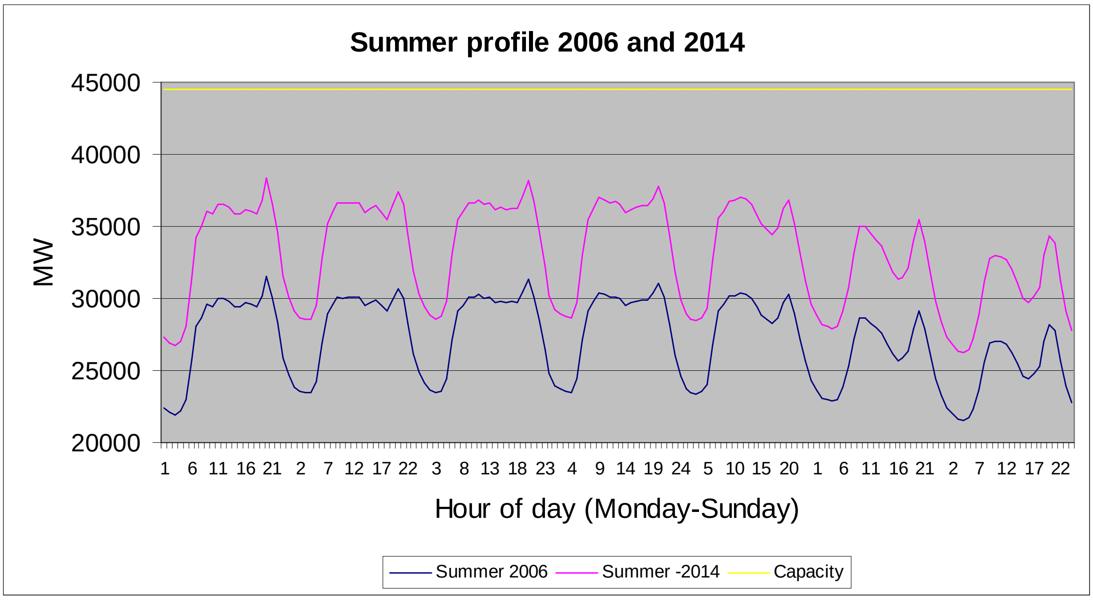

Figure 6-2: Average profile (Summer 2006 and 2014)

Figure 6-3 illustrates an average winter profile for 2006 and 2011. The data for 2006 is the actual average winter profile and the data for 2011 is an assumption based on a growth of 2.5% per annum from 2006 to 2011. The yellow line represents 93% of the installed capacity in 2011.

Figure 6-3 shows the difference between the demand profile and the maximum available supply is not much (1593MW for Wednesday during the TOU evening peak period). The maximum capacity will also not be at this level throughout each day and will also differ daily. A growth rate of 2.5% per annum is also not high and once again if the worldwide economy regains the growth we seen until late in 2008, the evening peak will exceed the available supply (exceed supply with 362MW during the TOU evening peak period on the Wednesday at a growth rate of 3.5% per annum).

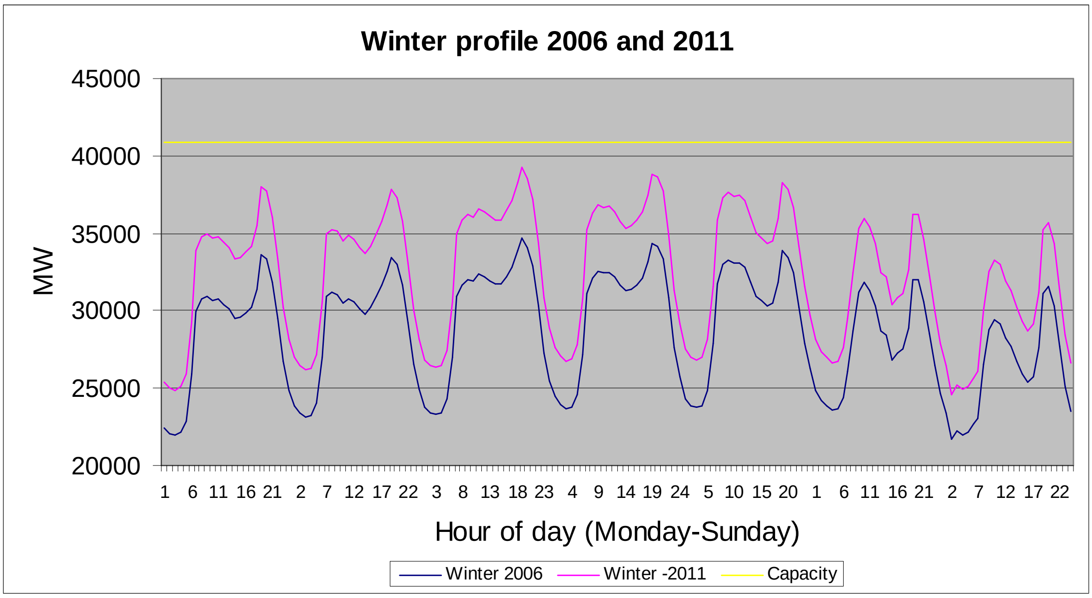

Figure 6-3: Average profile (Winter 2006 and 2011)

Figure 6-4 illustrates an average winter profile for 2006 and 2014. The data for 2006 is the actual average summer profile and the data for 2014 is an assumption based on a growth of 2.5% par annum from 2006 to 2014. The yellow line represents 93% of the installed capacity in 2014. Figure 6-4 shows that adequate capacity will be available for the supply to meet the demand after 2014 if the growth rate remains between at 2.5% per annum and this will remain the case unless the growth rate increases beyond 4.5% per annum.

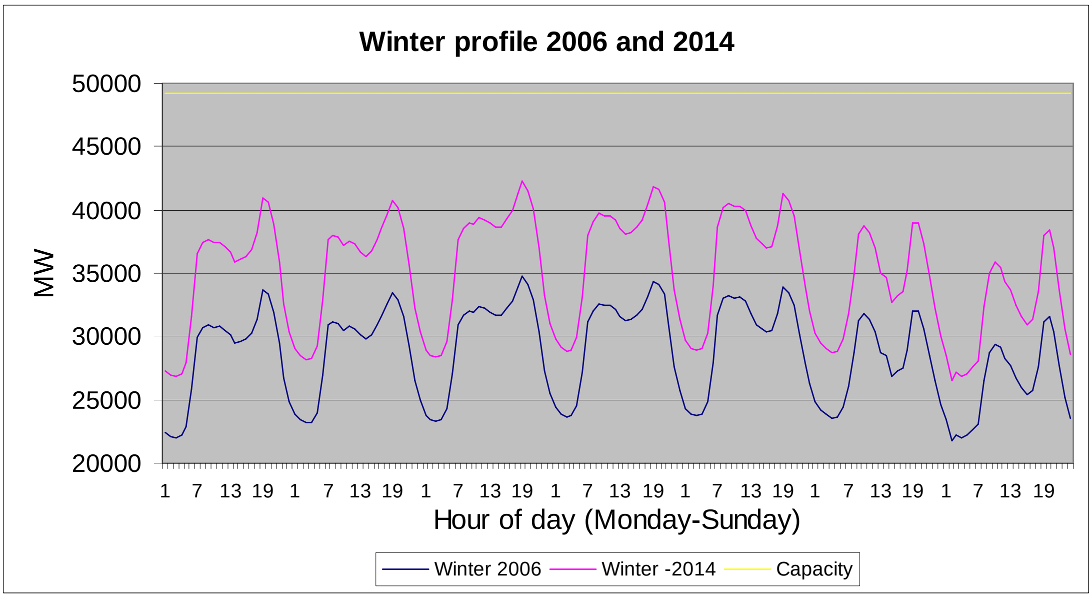

Figure 6-4: Average profile (Winter 2006 and 2014)

6.2.1 Results

Load management and DMP will play an important role to manage peak demand in the short to medium term. The growth rate of electricity consumption and the available capacity also affects the type of technologies required to manage peak demand. The analysis in this chapter indicates that load management and DMP will play an important role from now to at least 2013. However, if the growth rate of electricity consumption can be reduced to between 1 and 2% par annum, the need for load management and DMP initiatives will decline.

6.3 Load management initiatives and possible effect on the power system

In the previous section, it was clear that load management and DMP initiatives will play an important role to manage peak demand in the short to medium term. The way these types of initiatives are implemented plays a vital role in determining the success of the initiatives. The purpose of this section is to analyse load profiles in order to establish a possibility of optimising load shifting and DMP initiatives.

The average weekly profile for 2006 (summer and winter), as well as the profile for Week 4 (summer) and Week 27 (winter) were used for this illustration.

The weekly profiles are represented in Figure 6-5 and the daily profiles for the high and low-demand season are represented in figures 6-6 and 6-7. As is the case with the analysis in Chapter 3, it is once again very evident that the high-demand season (winter) has much higher peaks than the low-demand season (summer), as illustrated in Figure 6-5.

DMP can add value when constraints are experienced, as no load will be added to the system during another time period. Curtailment through the load management programme will also be able to add value during times of constraints, but due to the regulatory policy [4], the contribution of curtailment through the load management programme is limited to the tariff peak periods. Load shifting initiatives is, however, different in that the load shifted from one period will be required in another period. Figure 6-6 and 6-7 highlights load can be shifted to after 21h00.

Figure 6-5 illustrates that the potential to shift load in the winter months is much higher than the possible load shift during the summer months due to higher peaks in winter than in summer. The summer profile is very flat compared to a winter profile. A number of units are also unavailable during summer months due to the maintenance season. It can be concluded that load shifting in summer months are not as effective as load shifting during winter months.

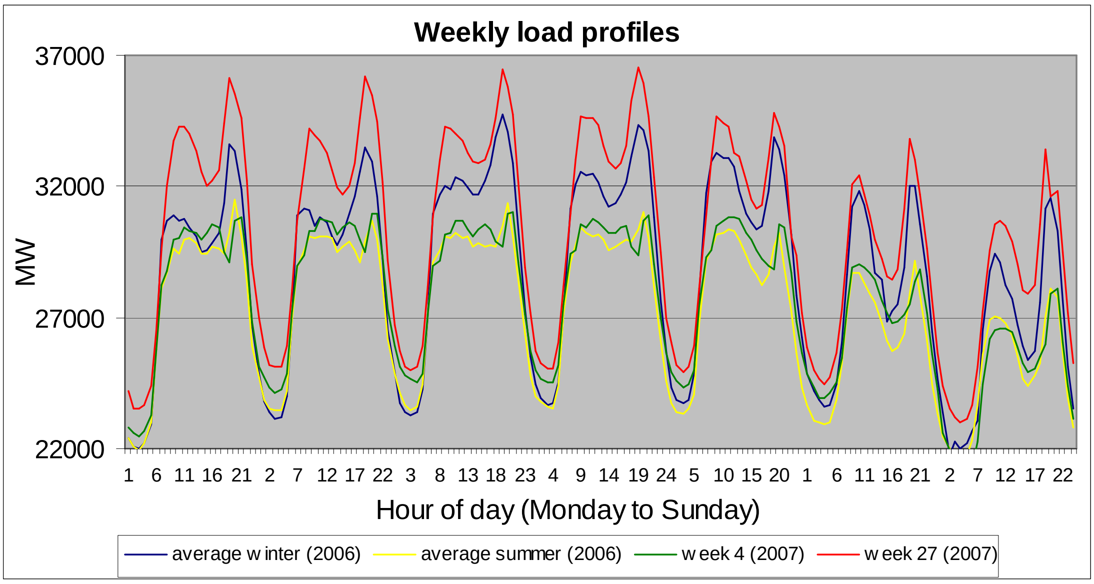

Figure 6-5: Weekly load profile (high-demand and low-demand season)

The data used in Figure 6-6 is the average load profile for Day 1 during the high-demand season (2006) and the actual load profile for Week 27 (winter 2007) on the same day. The system sent out (average 2006 winter) peaked at 33 628MW with a daily low of 21 989MW. The system sent out for Week 27 (day 1) peaked at 36 147MW, with a low of 23 495MW.

The difference between the highest and the lowest demand was, therefore, 11 639MW and 12 652MW respectively, leaving an opportunity for various load shift initiatives from around 20:45 to 21:00. Different types of load shift initiatives will however provide different results and because come back load can not be controlled by Eskom, curtailment initiatives is still a better option. Figure 6-6 further shows that the morning peak only drops substantially at around 13:00. Therefore, a load shift initiative in winter months before 13:00 might not be adding any value.

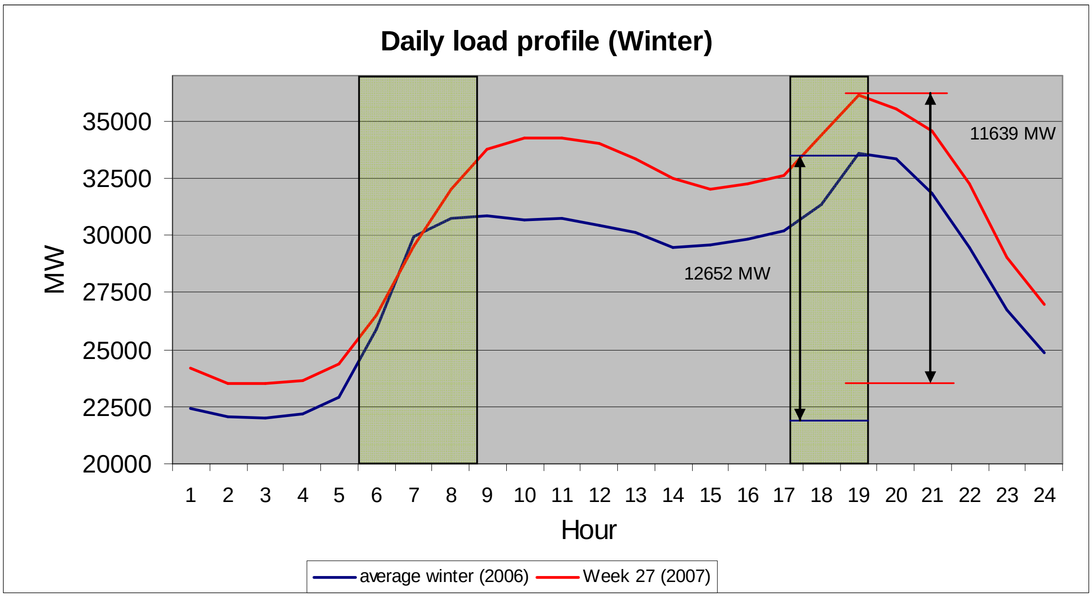

Figure 6-6 Daily load profile (high-demand season)

The data used in Figure 6-7 is the average load profile for Day 1 during the low-demand season (2006) and the actual load profile for Week 4 (summer 2007) on the same day. The system sent out (average 2006 summer) peaked at 31 509MW with a daily low of 21 940MW. The system sent out for Week 4 (day 1) peaked at 30 860MW with a low of 22 451MW.

The difference between the highest and the lowest demand was, therefore, 9 569MW and 8 409MW respectively, leaving a smaller opportunity for load shifting during summer months than for the winter months. By analysing Figure 6-7 further, it is clear that the morning peak remains very constant during the day (06:00 to 21:00).

The flat profile also means that any load shifted during the day (06:00-21:00) may create new peaks. As load shifting during the summer months will only add substantial value after 21:00, the current load shift initiatives are not optimal. In fact this might be more of a disadvantage to the system than a benefit. Once customers have the technology to shift load, the possibility exists that the customer will shift this load to benefit from the monetary savings. The NERSA policy which was designed to assist with capacity constraints might therefore even contribute to the constraints experienced due to the demand and comeback loads experienced after 20:00.

Even if load shifting initiatives are completely stopped, the initiatives that was already implemented or currently under implementation should be managed in a more active way as not to create new constraints.

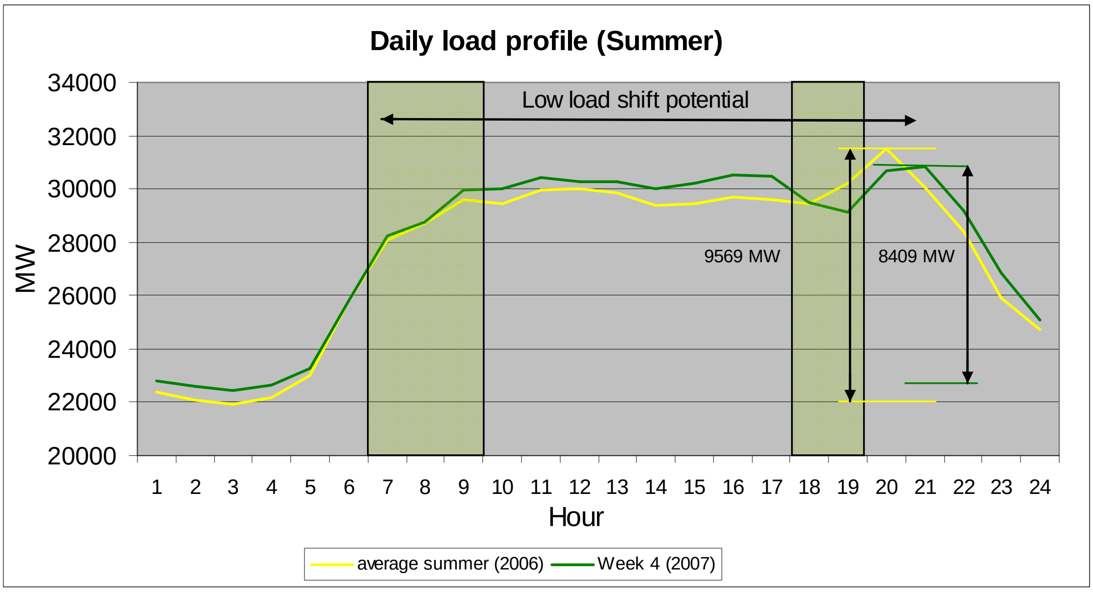

Figure 6-7 Daily load profile (low-demand season)

6.3.1 Results

Load management and DMP initiatives can be used to manage system peaks. Curtailment through the load management programme and DMP can add value at any time when constraints are experienced. However, only DMP is managed in a way to respond during times of constraints. Load shifting can also be used to manage peak demand, but does not add much value in its current form.

The way load shifting is implemented creates a further problem in that load is shifted to periods when access capacity is not necessarily available. As more load shifting projects come on line (currently being installed), more constraints might be experienced during some days in any specific hour/season. Load shifting have more advantages during winter months than during the summer months due to the flat profile during summer.

6.4 A dynamic approach to load management

The analysis in the previous chapters highlighted that load management initiatives shift/curtail load effectively. It was also evident that network constraints occur during the TOU peak periods. It was also noted that constraints also generally occur before and after TOU peak periods. Load shifting initiatives are only used during the tariff peak periods and therefore, could add to the constraints in the hours after the TOU peak periods.

The system operator is not able to request the dispatch any load management initiatives as is the case with DMP. Load management might not add value throughout any specific year due to seasonality and the associated consumption patterns. In order to have a more dynamic approach to load management, the question arises whether load management initiatives and DMP can be integrated, or rather if load management can be dispatched as DMP (more active/dynamic). Due to the funding mechanisms, DMP and DSM cannot be intergrated as a programme. However, the management of the available MW can be grouped with DMP as long as the repayments and contractual obligations can be adapted accordingly.

The findings identified by the Electric Power Research Institute (EPRI) in Chapter 2 [19] highlighted the DSM experience gained in the USA since the 1970s. Static DSM initiatives slowly deteriorated up to a stage where customers no longer wanted to participate in any of the DSM programmes that were on offer at the time. These programmes mainly became non-viable due to the fact that the utility did not benefit from them and subsequently the customer was not rewarded for a response. The following problems are identified with load management options associated with vertically integrated utilities [19]:

- Programmes normally address limited load shape objectives. With load management, only the TOU peak periods is currently targeted.
- Participation is often limited to customers with specific end-use characteristics. Participation in the industrial environment is limited to customers who can curtail/shift in access of 0.5MW.

It is, therefore, necessary to change the current approach and to convert the current static load management into a more dynamic approach where customers may be allowed to respond at any time as long as the response is determined by the system operator. The time a customer shifts/curtails load might be a pre-arranged time between the customer and the system operator based on a week or day-ahead schedule.

This will be possible due to the forecasts done by the system operator. A more dynamic approach might be further developed to allow customers with enabling technologies and processes to respond to network requirements even at a shorter time period.

In chapter 4 it was evident that some load management initiatives can shift/curtail load at any time, while with HWCs, the maximum load shift potential exists during the TOU peak tariff period [37]. The MW potential of all DSM load management projects are represented in Table 6-1. The total amount of MW is made up of individual projects as explained in Chapter 1. These projects include projects that have already been completed, projects that are currently under implementation and projects that are currently either in the approval process or in procurement.

Table 6-1 shows the possible load shift and curtailment potential available to DSM (projects are included that have been audited and found to be feasible, though not yet implemented). These initiatives, if and when implemented, will generally be available during the tariff peak periods, but by introducing a dynamic approach, some of the MW could be available at any hour. However, only the exact quantity of MW available to respond in the tariff peak periods are known at this stage and responses during other hours should be investigated.

Table 6-1 Load shift/curtailment potential

	Total load management	**Total load shift**	**Total curtailment/clipping**
Not contracted to date (audits and feasibility completed by ESCos)	297.54MW	233.2MW	64.26MW
Contracted/implementation	210.42MW	169.82 MW	40.6MW
Completed	324.83MW	295.89MW	28.94MW
Total potential	832.80MW	699MW	133.8MW

Of all the projects, 71 were randomly selected and analysed to establish if load management initiatives can be more dynamic. For this analysis, HWC initiatives were excluded and attention was paid to industrial and mining initiatives. The 71 projects represents 38% of the total projects currently at DSM. The 71 projects included load shifting and curtailment initiatives. Of the 71 projects that was analysed, 70 projects can become more dynamic if allowed. A huge opportunity, therefore exist for dynamic DSM.

The reason why potential projects are not proposed in a more dynamic format is due to the requirements of the NERSA policy. If a more dynamic approach can be adapted, projects can be simulated individually to determine the ability of each project's flexibility. A project might be able to shift/curtail load for longer periods of time (which varies according to seasons).

6.4.1 Results

It is possible to dispatch DSM initiatives at times other than the TOU peak periods. Research in this, as well as previous chapters, indicated a lack of flexibility and initiative as far as load management is concerned. DSM load management can add more value if it is implemented in a more dynamic way. Customers responding in times other than peak tariff periods will have financial implications and customers will need incentives to shift/curtail load at other time periods.

6.5 Desired signals through tariffs

The analysis in Chapter 3 highlighted that the TOU tariff can send a much stronger signal to customers. Without proper pricing signals, customers have no incentive to change their consumption behaviour in response to system constraints or supply shortages [26]. The purpose of this section is to investigate different tariff options and to recommend a way forward. Tariffs will be investigated at a high level and their associated advantages and disadvantaged will be listed.

Internationally, a number of rate options exist. Many utilities have offered real-time pricing and some have recently added a critical peak rate [29]. In the absence of an electricity market, it might be necessary to have electricity tariffs that are priced above and below efficient price levels during different time periods. Money over-recovered could then be used to fund capital expansion projects, therefore, reducing the revenue requirement for the following regulatory approval period. Table 6-2 was drawn up using the general characteristics of basic tariff options.

Table 6-2: Tariffs and associated characteristics

	Time of use (TOU)	**Real-time (block rate)**	**Critical peak rates**
Metering	Relative simple	Hourly metering	Hourly metering
Period	Fixed periods	Changes hourly or as consumption increases	Short periods of time (contracted in advance)
Desired effect	Shift load from high to low price periods	Shift load during times of constraints: create demand elasticity	Shift load during times of constraints: create demand elasticity
Disadvantages	Doesn't reflect actual costs	Complex metering	Complex metering Short notice periods
Costs	Based on long run marginal costs	Short-term pricing	Short-term pricing
Best suited	All customers	Mostly industrial/large	Mostly industrial/large

Real-time pricing (also referred to as block rate tariffs) and critical peak prices will definitely send a very strong signal to electricity customers. These are also the types of tariffs utilities introduced internationally in preparation of electricity markets. In electricity markets, constraints are managed economically, whereby electricity is very expensive during times of constraints.

Although critical peak rates and real-time prices could result in a desired load shape for any utility, there are legal, contractual and financial implications associated with changes to tariffs. The development of a new tariff is associated with a rigorous costing exercise. The time to implement new tariffs is also associated with commissioning of new communication and metering technologies. Critical peak rates and real-time prices can introduce more elasticity in the demand [26], [30] for electricity, however, the time frame left to implement these tariffs is not sufficient (section 6.2).

The quickest option is to introduce new TOU tariffs. TOU tariffs are already approved by NERSA and the periods (high, standard and low-demand, as well as seasonal differentiation) can be adjusted with the least delays. As long as Eskom doesn't over-recover during any financial year, it should not be a problem. A new more cost reflective TOU tariff will send clear signals to all customers of electricity in the shortest time period.

For customers, there is an optimal point of load shift beyond which further shifting will not be viable. The higher the customer's load factor, the less scope there is for load shifting without incurring a network charges penalty. Therefore, it is critical to roll TOU metering out to residential customers. These customers have a huge load shift potential due to their low load factor and the total effect will contribute substantially. To date, only pilot TOU projects have been implemented in the residential sector, and these should be able to inform how TOU can be rolled out to residential customers nationally. New technologies are becoming more cost effective for smaller customers, due to innovation in information technologies and power electronics [43].

6.5.1 Daylight savings and the introduction of time zones

Daylight saving time (DST) is not a new concept and was implemented in Europe during the First World War and during 1918 in the USA [41]. A number of articles and publications are available on this subject and the indication is that DST is effective. Several suggestions and recommendations have recently been mentioned in articles regarding the introduction of a daylight-savings system or time zones in South Africa. The Mail and Guardian newspaper published an article where a potential demand shift of 560MW was suggested by D. Joubert from Eskom Generation [42].

Eskom’s Resources and Strategy Department initiated a research project with the intention to determine the potential benefits of multiple time zones for South Africa [44]. Table 6-3 shows the annual peak demand could be reduced by between 192MW and 220MW with the introduction of two time zones and 258MW with the introduction of three time zones [44].

Table 6-3: Annual Benefit of Diversity [44]

Scenario		2007
1	Western Region separated	192 MW
2	Northern and Eastern Regions separated	222 MW
3	Three Time Zones	258 MW

Although energy consumption could remain the same, it is possible to see a slight improvement in energy consumption due to more efficient use of daylight. The biggest advantage will however be applicable to a shift in demand to another period. The Director General of Public Enterprises Portia Molefe, pointed out that there was still much more to consider "and work around" before a decision would be made on the introduction of more time zones in South Africa [45]. The cost, complexity and subsequent benefits of implementing time zones will ultimately dictate if it will be implemented some time in the future.

6.5.2 DSM and the impact on the Economy

All DSM initiatives come at a cost to the economy and the costs of this are generally shifted to the end user. With the higher expected tariffs over the next couple of year’s energy efficient initiatives will become more viable that what is currently the case.

As mentioned in chapter 4 and 5, DSM load management and DMP comes at a cost to the economy too. With DSM load management all initiatives are funded by a levy on the electricity tariff established by NERSA. Load management initiatives are paid for in advance and a response is expected during the contract period as agreed to between Eskom and the customers.

DMP customers are paid when customers respond and the response is guided by network or capacity constraints. The costs of DMP are expensive but it must be noted that DMP is more cost effective than the alternative, which is making use of gas turbines to meet peak demand. The exact costs of the load shedding during 2007/8 on industries and the economy can not be accurately quantified but the cost of unserved energy (CUE) is estimated to be R 50bn [46].

All the initiatives mentioned will have an effect on the country's economy and in the long term it is expected that more efficient measures will become a natural choice. These energy efficient measures will also help to reduce the overall demand profile.

6.6 Research questions – results

Research question	**Anticipated outcome**
How do customers respond to the TOU tariff signal and are the tariff signal still effective?	Most customers respond to TOU tariff signal.
Research outcome	
From the research it was found that (Figure 3-2, 3-3 and 3-4) not all customers respond to the TOU tariff signal. More customers respond during the high-demand season than during the low-demand season (Figure 5.1), which is an indication that the higher price has an effect on a decision to respond. It was further found (Figure 3-1) that the fluctuation per season was not substantial enough to indicate an overall effective TOU tariff signal. The conclusion that can be reached is that some customers are more sensitive to higher electricity prices than others. The tariff signal seems to be less effective than when it was initially introduced.	

Research question	**Anticipated outcome**
Are system peaks and TOU peak periods aligned?	The system peaks and tariff peaks are no longer aligned.
Research outcome	
From the research it was found (Figure 3-9) that system peaks and tariff peaks are still aligned. The highest demand generally occurs within the TOU tariff period. The research further shows (Figure 3-5 and 3-6) that a number of constraints occur out of the TOU peak periods. This is further supported by Figure 5-1 and Table 5-1 which indicate the expected DMP responses in periods other than TOU peak periods.	

Research question	**Anticipated outcome**
Are system peaks still aligned?	System peaks are no longer aligned.
Research outcome	
From the research it was found (Figure 3-7 and 3-8) that system peaks are still aligned. The huge increase in consumption over the past few years is causing the peaks to be much higher if compared with historical data, but the peak periods remain the same. Peaking generation must	

be used to meet the demand in a number of cases where this was historically used purely over the TOU tariff period.

Research question	**Anticipated outcome**
Can load management shift load successfully?	DSM technologies shift load successfully.
Research outcome	
From the research it was found (Figure 4-2, 4-4 and 4-5) that load management initiatives can shift load effectively.	

Research question	**Anticipated outcome**
What are the advantages and disadvantages of load management?	Load shifting/curtailment may occur when no constraints are experienced, which could lead to a loss of income for the utility. Load shifting can add value but new peaks might be created.
Research outcome	
From the research it was found (Figure 3-6, 6-6 and 6-7) that peaks generally occur in the TOU tariff period, but are also very evident in the hours before and after the TOU tariff peaks. It was further found that peaks occur at any time during the day, depending on network conditions (Figure 5-1, 5-3 and Table 5-1). During 2007, DMP was dispatched on average 37.73% (annual average) in hour 17 and 5.04% (annual average) in hour 19 (Figure 5-1), which highlights what role load management might have played during this time.	

Research question	**Anticipated outcome**
Can DMP curtail load successfully?	DMP is able to curtail load successfully.
Research outcome	
From the research it was found (Figure 5-4, 5-5 and 5-6) that DMP is effective in curtailing load.	

Research question	**Anticipated outcome**
What are the advantages and disadvantages of DMP?	DMP can curtail load at any time.
Research outcome	
From the research it was found (Figure 5-2, 5-3 and 5-4) that DMP can be dispatched to curtail load in any hour when system constraints are expected or experienced. It was further found (Figure 5-6) that DMP contributes very effectively with frequency control. Limited customer	

participation in DMP is a disadvantage. More participants create competition and reduce customer fatigue.

Research question	**Anticipated outcome**
Will DMP and load management be required in future?	Load management and DMP will be required to manage peak demand periods.
Research outcome	
From the research it was found (Figure 6-1 and 6-3) that load management and DMP initiatives will add value in managing constraints in short to medium term.	

Research question	**Anticipated outcome**
Can load management initiatives become more dynamic?	The two technologies can be integrated.
Research outcome	
From the research it was found (Section 6.4) that some load management initiatives can be technically integrated into DMP. Policy issues, however, don't allow this initiative. It was further found (Figure 5-5) that smaller participants can successfully be grouped together to ensure a valuable response and that technologies are in place to accommodate multiple participation in DMP.	

Research question	**Anticipated outcome**
Can new tariffs assist with the expected capacity shortages in the short term?	Real-time pricing and critical peak rates will assist to achieve a desired load shape objective.
Research outcome	
From the research it was found (Table 6-3 and Section 6.5) that to manage the current and future constraints expected in the short term, the TOU tariff is a feasible option. However, the tariff periods and seasonal discrepancies need to be corrected. This research also indicated (Figure 4.6) that the most feasible option is encourage more Energy Efficient initiatives or load management initiatives with a energy efficient component. Energy Efficient technologies will reduce the overall demand profile. A more cost reflective tariff will also encourage Energy Efficiency.	

CHAPTER 7: OVERALL VIEWPOINT

7.1 Conclusions and recommendations

This research show that load management and DMP can make a significant contribution to the electricity supply system if these initiatives are managed optimally. The tools available to achieve a desired load shape objective may be effective, but must be adjusted to ensure the maximum benefit is realised. In some cases, the current incentives are not sufficient to ensure a desired load shape.

The current time of use (TOU) tariff signal is not sufficient. The TOU tariff peaks must be aligned with system peak periods. The TOU tariff must further be reviewed to ensure that a desired load shape objective can be achieved. The seasonal definitions in light of changes to the demand profile (price, peak seasons and peak hours within each season) should also be reviewed.

More participants on TOU tariffs must be introduced. These tariffs must also be introduced in the residential sector. A huge opportunity exists in the residential sector due to current consumption patterns and the low load factor associated with these customers. With new generation metering technologies, residential TOU metering has become a viable option internationally.

This research further proves that DSM initiatives can be more effective if current initiatives are optimized and load management evolve into a more dynamic approach where system constraints dictate a response rather than the TOU tariff structure.

It is therefore possible to convert a substantial quantity of load management initiatives from the current static programme to a more dynamic approach. This will further allow for more participants in DMP without the usual costs associated with DMP (customers expected to respond due to money invested in EEDSM initiatives [4] and not all paid as the case with DMP). The system will be managed better and customer responses will be guided by system and network constraints. Load management programmes unable to become more dynamic will add further value if the TOU tariff can be adjusted to reflect actual system constraints.

DMP is effective in achieving a desired load shape objective. More participants in DMP will bring DMP more in line with international best practices. With more participants, DMP will also reflect market prices (prices at which customers are willing to reduce load).

Both load management and DMP can be used to curtail and shift load effectively. Both load management and DMP must be retained to complement current supply side options. Load management and DMP further contribute to the system because network constraints do not affect these demand side technologies as is the case with supply side options.

7.2 Areas for further research

Further research on the following topics will be able to guide future strategies and initiatives:

- Implementation strategy for dynamic load management, whereby load management initiatives can be dispatched at any time of the day.
- The relationship between the growth in the economy and the growth in electricity consumption.
- Viable energy efficient technologies able to reduce the overall demand profile.
- Cost of various DSM initiatives to the economy.

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