REAL TIME PRICING AS A DEMAND SIDE MANAGEMENT OPTION FOR ESKOM

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OPSOMMING

"REAL TIME PRICING" AS 'n VERBRUIKERS GEDRAGSBESTUUR OPSIE VIR ESKOM

In die vroeë tagtiger jare het die Suid-Afrikaanse ekonomie redelike stabiele groei beleef, wat weerspieël is deur soortgelyke groei in die elektrisiteitsindustrie. Eskom het daarop reageer deur lae bedryfskoste steenkool kragstasies op te rig. Vroegtydige optrede was noodsaaklik weens die lang leityd in die oprigting van sulke kragstasies. Die ekonomie het in teenstelling egter afgekoel teen die vroeë negentigs en Eskom het oorkapasiteit van elektrisiteit in die oë gestaar. Terselfdertyd het die politieke situasie in Suid-Afrika drasties verander en Eskom verbind hulself tot grootskaalse elektrifisering van onderontwikkelde huishoudings.

Die onomkeerbare resultaat was egter 'n swak nasionale lasprofiel, wat hoë algehele generasiekostes tot gevolg het. Dié nuwe probleem het gevra vir óf 'n ander samestelling van generators óf Verbruikers Gedragsbestuur (normaalweg genoem "Demand Side Management" of DSM). Dit sou beteken dat Eskom óf addisionele spitsaanvraag kragstasies teen hoë kostes moes oprig óf die tyd van die dag en manier waarop klante elektrisiteit gebruik moes beïnvloed. Huishoudelike verbruik, wat die sondebokke is, is moeilik om te beïnvloed en 'n manier moes gevind word om industrieë te beïnvloed sodat hulle 'n omgekeerde profiel as dié van huishoudelike verbruikers sal skep.

"Tyd-van-Verbruik" tariewe is geïmplimenteer, gebaseer op Eskom se langtermyn behoeftes, wat weerspieël word deur drie tyd-gedifferensieerde energie pryse. Hierdie tariewe is staties vir ten minste 'n paar jaar en kon dus nie die korttermyn behoeftes van Eskom aanspreek nie. Tot op datum kon hierdie tariewe nie daarin slaag om die industriële verbruikspatroon noemenswaardig te beinvloed nie en 'n alternatief moes gevind word.

“Real Time Pricing” (normaalweg na verwys as “RTP”) is ‘n uurlikse tarief, gebaseer op die korttermyn kostes verbonde aan die verskaffing van elektrisiteit en is geïdentifiseer as ‘n moontlikheid om industriële laspatrone te verander. Niemand kon egter tot dusver bepaal wat die invloed op Eskom se sisteem, sowel as die koste implikasies daarvan sou wees as RTP dit kon regkry om die bestaande industriële lasprofiel te verander nie.

Die skripsie wat volg poog om hierdie vraagstuk te beantwoord en verskaf in die proses ‘n antwoord of RTP gebruik kan word as ‘n DSM gereedskapstuk - om te verhoed dat Eskom nodig sal hê om addisionele spitsaanvraag kragstasies te bou. Dit wys dat, hoewel RTP op Eskom se korttermyn behoeftes gebaseer is, dit ook die langtermyn behoeftes aanspreek. Die dokument wys uit dat kostebesparings relatief klein is gedurende die tydperk waar Eskom oormaatkapasiteit beleef, maar dat besparings gou noemenswaardig raak sodra die langtermyn behoeftes in gedrang kom.

Die skripsie sluit af met ‘n aanbeveling dat, hoewel dit blyk dat DSM as gevolg van RTP oor 4 – 5 jaar beter resultate toon, die verwagte leityd om RTP tot sy volle potensiaal te ontwikkel, in ag geneem moet word. Vervolgens beveel dit aan dat RTP onmiddellik geïmplimenteer moet word om te verseker dat die produk ten volle gevestig is teen die tyd dat DSM werklik kritiek raak. Dit sal Eskom tyd gee om die produk te verfyn en vervolmaak terwyl die industrie se reaksie ten opsigte van dinamiese tariewe ontleed kan word.

ABSTRACT

REAL TIME PRICING AS A DEMAND SIDE MANAGEMENT OPTION FOR ESKOM

In the early 80s the South African economy grew at a fairly steady rate, which was echoed by similar growth in the electricity industry. Eskom responded by building more low running cost, coal-fired power stations. Early action needed to be taken because of the lead-time in building a coal-fired power station. The economy, however, slowed down by the early 90s, and Eskom feared a situation of over capacity regarding the supply of electricity. At the same time, the political situation in South Africa changed dramatically, and Eskom embarked on a massive electrification programme for under-developed households.

The inevitable result was a poor national load factor, causing high overall generation cost. This new problem called for either a different mix of generation plant or Demand Side Management (generally called DSM). This means that Eskom needed either to build expensive additional peaking-plant or to influence the way and time of the day customers consume electricity. Domestic consumption, which is the culprit regarding the poor load factor, is difficult to influence, and a way needed to be found to influence industry to consume electricity in a way that will create an inverse profile to that of the domestic consumer.

"Time of Use" tariffs were introduced; based on long-term needs of the utility, which are expressed through three time differentiated energy rates. These tariffs are static for at least a few years at a time and thus could not address the short-term needs of the utility. To date these tariffs have failed to influence substantially industrial usage patterns, and an alternative needed to be found.

Real Time Pricing (generally referred to as RTP) is an hourly tariff, based on the short-term cost of providing electricity, and was identified as a possible way to influence industrial load patterns on a daily basis. However, to date, no one could indicate what

the real effect on Eskom's system and costs would be if RTP managed to alter substantially the current industrial load profile.

The dissertation that follows endeavors to answer this question and, in doing so, gives an indication of whether RTP can be used as a DSM tool to prevent Eskom from having to build additional peaking power stations. It shows that, though RTP is based on Eskom's short-term needs, it also manages to address the longer-term needs of the utility. It indicates that cost savings are relatively small during the period Eskom is experiencing over-capacity, but savings quickly become noticeable as the longer-term needs come into play.

The dissertation concludes with a recommendation that, though DSM through RTP seems to be worth more in 4 to 5 years, cognisance needs be taken of the lead time anticipated in developing RTP to its full potential. In conclusion, it recommends immediate implementation of RTP to ensure the product be fully established by the time the need for DSM becomes critical. This will allow Eskom time to refine and perfect the product as well as to study industry's reaction to dynamic pricing.

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CHAPTER 1: INTRODUCTION

1.1 Introduction

During the early to mid 80s, the South African economy experienced a period of relatively high growth. Likewise, electricity consumption increased on average by 2.79% per year till the mid 90s (Figure 1.1 - NER, 1998:3). Extrapolating the economic and electricity growth figures, at that time, together with the optimistic views for South Africa in the late 90s, led the Eskom forecasters to believe Eskom's generating capacity would have to be increased by the turn of the century.

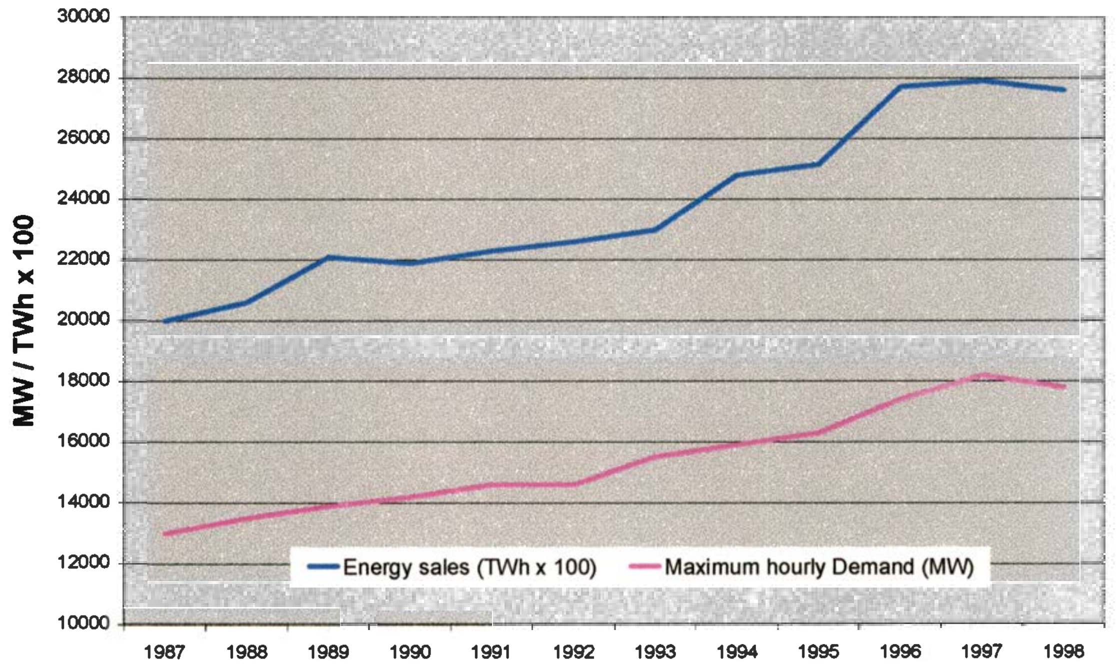

Figure 1.1 *Yearly growth in electricity sales (NER, 1998:3)*

The industrial sector was identified as the main area of growth, with a typical flat load profile. Taking all factors into account and with coal being readily available in South Africa, thermal base load generation was seen as the best solution to the anticipated forthcoming shortage in generating capacity. Eskom accordingly embarked on building another 6 pack, coal-fired, base load power station – Matimba power station.

On the turn of the decade, however, the economy slowed down and a few years later the consumption of electricity followed the trend (Refer to Figure 1.1). Eskom realised that a major portion of its sales to the gold mines was at risk and the anticipated growth in industrial usage would most probably not be realised. The political situation in South Africa also changed and Eskom's national strategy was altered to focus on massive electrification of under developed communities. In the meantime Matimba Power Station was already committed and it seemed a sound way of counteracting the now anticipated over-capacity situation.

In principle, the electrification drive was a sound answer to the decline in sales, but it imposed new problems. By the mid 1990s, Eskom's Annual Report (1995:25) reported the growth in maximum demand to average 4.4% for the year 1994/95, whilst energy consumption grew by only 2.7%. This pattern is typical to rural domestic load, and Eskom's long-term forecasters anticipated that Eskom would experience an increase in peak to off-peak demand ratio of 17% by the year 2020 (Eskom's Integrated Electricity Planning document - IEP Vol.4, Dec. 1998:7). The result is a degraded load factor or percentage utilisation of committed generating plant. Though the national peak demand could easily be covered, it would have to be done with base load plant, as hydro and gas-fired peaking plant is not readily available in SA. This will result in over-capacity situations during hours outside hours of national system peak, which again may result in the tripping of generators if run at too low load factors.

With South Africa's unique constraints in mind and the rapid fluctuation in demand over any 24 hour period, the only solution to Eskom's new dilemma was to change the load consumption pattern of its customers. Changing the usage patterns of domestic consumers (which are creating the problem), however, is very costly and difficult. The industrial sector is a much easier target. In reaction, a range of time differentiated tariffs were introduced during the mid 90s, called Megaflex, Miniflex and Ruraflex. The intention was to incentivise consumption during system "off-peak" hours and put a premium on consumption during those hours of normal system peak.

Though this initiative had some spin-offs, it only partly solved the problem, focusing only on the longer-term problem of a worsening load factor. The effect was not as big as anticipated and, maybe the biggest shortcoming, the high priced hours were static and based on the long-term cost of generation. These tariffs could not follow the short-term cost of generation, and day-ahead scheduling of generation plant remained sub-optimal. A tariff was needed that could follow the day-ahead supply versus demand situation and influence customers' load patterns in a way that would optimise short-term generation scheduling and costs. Such a mechanism is called Real Time Pricing (RTP).

RTP is a new concept introduced internationally by leading utilities to expose customers to the supply versus demand dynamics of electricity generation. Internationally RTP is mainly driven by competition and is used to offer customers choice and lower energy prices through shifting the risk from the utility to the consumer. However, as it is a mechanism that dynamically prices electricity according to the short-term cost of generating the last unit (kWh), it could be the answer to Eskom's dilemma. The tariff prices electricity on an hourly basis according to the next day's anticipated cost of generation and distribution. It thus signals whether the system is anticipated to be constrained or not – through either very high prices in hours of anticipated constraint or marginal prices when the system is to be lightly loaded.

This principle could be used by Eskom to signal its dilemma to large industrial customers – offering them "cheap" energy in hours of inevitable surplus spinning reserves and signaling/incentivising demand curtailment in hours when committed generators cannot meet the demand. Industry will, through this product, be able to participate voluntarily in balancing the peaks in national system demand.

The benefit of RTP to Eskom might be twofold: First, an increase in sales in hours of no system constraint and a resulting rectification of the decline in sales and profit as has been experienced over the last few years. Second, it may provide a mechanism to involve industry in managing the cost of generation and drive down the overall price of electricity. The dissertation to follow, however, will only deal with the second issue.

1.2 Problem statement

Although RTP has already successfully been introduced by more than 30 utilities internationally, none of them did it for the reasons explained in paragraph 1.1, hence no documentation exists on the load and cost optimisation effects thereof. Likewise, the impact that load shifting under RTP conditions might have on the cost of generation has never been quantified in Eskom, though the tariff is authorised to be piloted at a few customers. Eskom can thus not claim that RTP will be the answer to its problem of growing peaks, the consequential degrading in load factor and the high cost associated with sub-optimal scheduling of generation plant.

1.3 Objective of the dissertation

The primary objective of this dissertation is to *investigate the potential of the proposed RTP tariff as a demand side management (DSM) option for Eskom.*

Secondary research objectives will include:

- *Defining the cost implications to Eskom, brought about by RTP initiated DSM.*
  This will be done by determining the *net saving on daily running cost* to be realised through shifting one unit of electric power from a peak hour to a non-peak hour, as well as by determining the *net saving in terms of deferring the cost of building the next power station.*

- *Determining the minimum amount of load to be shifted to realise a saving.*
  This will be done through analysing historical scheduling of generators, and determining at what stage RTP load shifting would result in more optimal scheduling of generating plant. Only at this point the above-mentioned savings will materialise and become tangible.

- *Estimate the additional load shifting potential of South African industries, to be realised through RTP.*

  This will be done through gathering information and opinions from the experts within industry - through a combination of questionnaires and personal interviews.

1.4 Research methodology

Research into the quantification of cost savings, to be achieved through RTP load shifting, will inter alia be done through telephonic- and electronic interviews with electricity supplying utilities that have already introduced RTP. Likewise research on the cost of generation will be done through personal and electronic interviews with Eskom's Generation, Transmission, Energy Trading, Pricing, Policy, and Marketing sections. This will be backed by an intensive theoretical research in recent articles and other literature on RTP, load shifting, generating cost and the deferral of capital cost - to ensure the principles applied in satisfying the objectives are correct and current.

Questionnaires will also be completed with a representative number of Eskom's top customers in the deep level mining and smelter sectors. Through the questionnaires, it will be determined whether the required load shifting potential exists within these sectors to support the said objectives. Questionnaires will only be completed once personal interviews and/or presentation on RTP has been made to customers, to ensure that the information is captured as accurately as possible and the person completing the questionnaire understands the fundamentals of RTP.

1.5 Limitations of the study

This study on the potential of RTP as a DSM option for Eskom will be limited to the impact such a tariff might have on Eskom's cost of generating electric power. The fact that additional load shifting might increase energy losses in sections of the system whilst reducing losses in other sections, will not be taken into account, nor will it be quantified in this report, for it is seen as a separate engineering topic. Neither will the possibility of utilising RTP to increase energy sales be explored. Likewise, the effect DSM through RTP might have on the customers to participate in RTP, falls outside the scope of this dissertation.

Scheduling data and associated costs per generator are based on the actual data for 1998. More recent data are not readily available and 1998's data were the most updated data available at the time the dissertation was started. However, for this study intends to verify the principle of RTP being a DSM option, it is not regarded as a critical factor.

1.6 Defining core concepts

Deferred capital cost refers to the amount of capital that will not have to be spent at a pre-determined date, as the need no longer exists for expansion in generating capacity.

Demand side management (DSM) refers to action taken by a customer on a voluntary basis, in reaction to a signal from the supplying utility. Differently said, it is management of consumers' energy consumption by supply side/utility intervention.

Generation running cost refers to the hourly cost of generating electric energy and will only include cost of generation. This will be subdivided into short run marginal cost (SRMC) and long run marginal cost (LRMC), which respectively means the immediate fuel and labour cost of generation vs. the longer-term capital and financial cost of providing for generation capacity.

A **load profile** is the graphic interpretation of the percentage utilisation of any defined amount of available capacity, over a period of time, of supplying a specific load. It thus reflects the degree to which such installed capacity is being utilised.

Load factor expresses the load profile as a percentage utilisation.

Non-peak hours include all hours that are not defined by Eskom to be peak hours (See "Peak hours")

Off-peak hours, for the purpose of this study, has the same meaning as non-peak hours.

Peak hours include all those hours, defined as such, in Eskom's schedule of prices for products and services, in which the Eskom national system is historically under constraint.

Real Time Pricing (RTP) is a dynamic mechanism to introduce customers to the short-term value of electricity. Customers receive 24 hourly prices for electricity by 14:00 the previous day. The prices reflect the anticipated system conditions, and thus the availability of surplus power, with low prices if surplus power is available and, conversely, high prices whenever additional generation is needed to cover the demand for electricity or for those hours when surplus energy is not available on the system.

Supply side management (SSM) refers to action taken by the supplying utility, to manage supply. SSM and DSM thus constitute the two ends of managing the electricity system/grid.

Time-of-Use (TOU) tariff means a time of use differentiated tariff that prices energy and demand slightly higher in hours normally/historically identified as peak and standard hours. The cost associated with different hours gets priced yearly and hours are defined every 10 – 12 years.

Virtual power station is a concept used for committing an amount of load to be taken off the system, instead of generating the energy to supply this load. It is sometimes called a power station generating "nega-watts" or "negative watts". A virtual power station thus creates valleys in the existing demand profile, rather than generating electricity to supply additional demand or peaks.

CHAPTER 2: LITERATURE STUDY

2.1 DEFINING A UTILITY'S COST

2.1.1 A Utility's cost of service

To be able to understand and determine the costs/savings to be realised by a utility with the shift of load between any particular hours of the day, it is imperative that one should break down and cluster all costs involved in the complex system of generating and distributing electric power. Cost of electricity may be divided into two components, according to Wacker and Billington (1989:919), which is the cost of energy served to the end user and the cost of energy not served to the end user (the so-called "cost of unserved energy").

This paper will not enter into the debate around the cost of unserved energy, but rather look into the cost of energy served and maximising utilisation of generating plant. As been said in the limitations of the study, costs incurred - or saved - in distributing the power, will also not be included in this study. The intention of the dissertation is to determine what costs are involved in generating one additional unit of electric power (kWh) for a given period, to be in a position to tell whether it is worth incurring costs to shift load to another period where generating cost is lower.

2.1.2 The cost of producing electricity

Storage of electricity is very costly and it is thus necessary that a utility's production closely follow variations in consumption at all times. Hence, according to Todnem (1991:104), cost can be divided into:

- Cost related to *power*: The cost to dimension the system for the relevant maximum load.
- Cost related to *energy* usage: The cost of energy that is almost solely the fuel cost and cost of transmission losses.
- *Fixed* cost: The cost related to providing power facilities.

Currently in Eskom, and most utilities around the world, pricing of electricity is done from financial targets set by government or the utility itself, based on historic costs. The tariff structure ensures that sufficient sales revenue is raised to meet the operating expenses and debt service, while providing a reasonable contribution towards the capital required for future expansion. Each customer pays an average share of the cost of supply as determined by how much of the system capacity and fuel each consumer class used on average (Roos, 1996:32).

Calitz and Campbell (1991:8-19) illustrated that a tariff based on average costs is over simplified and cannot accurately reflect the true cost of supply, which calls for a tariff based on marginal or specific cost. However, there is no single characteristic of an electric utility's output to which all costs are proportional. There are administration and local capital costs, variable costs and fixed costs (Roos, 1996:32), as stated earlier. From these costs the average cost of each kWh, or the short run marginal and long run marginal cost of each additional kWh, can be computed over a given period of time.

Bonbright *et al.* (1988:418) defines short run marginal costs (SRMC) as a reflection of the additional cost of meeting an increment of demand in a specific hour, assuming the system plant and equipment cannot be altered. Long run marginal costs (LRMC), on the other hand, reflect the additional costs of meeting an increment in demand, assuming the plant and equipment can be changed to re-optimise the system. As mentioned by Tolley (1988:29), LRMC encourages an efficient allocation of resources by both producer and consumer, it indicates the cost consequences of increasing demand at any time and, provided that it is applied uniformly, it constitutes an equitable system of pricing.

According to Bonbright *et al.* (1988:30), supply costs can be further divided and one may say that *fixed costs* are short run costs that, in total, are insensitive to variations in output. Closely related to fixed costs are also irreversible sunk costs with the essential characteristic that the productive capital facilities are so specialised as to location or purpose, that they cannot easily be converted to alternative productive uses. He continues (1988:117) to argue that a restricted class of fixed costs are sunk costs which have already been irretrievably incurred, for durable investment can no longer be avoided or minimised through curtailment of output. Relevant costs, for the purpose of this study, are those costs that can still be avoided by the restriction of output. In short; the escapable or avoidable costs, rather than the fixed costs.

Marginal cost, in a general sense, for a given commodity or service, refers to the increase in total cost of providing the service or product, that is imposed on an organisation by a relatively small (marginal) increase in its rate of output (Bonbright *et al.* 1988:417). Thus, it is an incremental cost per unit of increased output. It is possible that marginal cost can be X cent/kWh, whereas average cost may be 2X (double the amount) or only ½X (half the amount) (Bonbright *et al.* 1988:419).

The last margin of capacity is always used at peak hour, and so the total cost of installing, depreciating, and maintaining it are focused on just a few units of use. This cost totally falls on peak-load use, which is responsible for requiring the capacity (Bonbright *et al.* 1988:459). In off-peak periods, fixed (capacity) costs are zero and variable costs may be low. It can be said that users of electricity during hours of system constraint should pay for all costs to be incurred to provide for additional capacity. This is, however, not 100% true, as off-peak users might enjoy the benefit of lower running cost generation as a result of more committed units (Bonbright *et al.* 1988:462).

The cost savings emanating from deferring the building of additional power plant to provide more capacity should be determined as a reduction in fixed cost. Care should also be taken that the most suitable power plant's costs are taken for such calculations, as peak demand generation calls for specific plant.

2.1.3 Scheduling of generation units

In Eskom, as in other large electricity supplying utilities, the generation system typically consists of various configurations of plant. Utilities generally utilise the newest or latest plant to provide the minimum or continuous base load demand, as their fuel costs are relatively low and/or capital costs are high. As seasonal/daily demands increase, high fuel cost equipment, such as gas turbines, is used to cover peaks in demand (Bonbright *et al.* 1988:404).

If demand increases more than the existing plant can produce, those less efficient generators that would otherwise be kept on standby reserve, must supply the enhanced output. Fuel costs will therefore increase per kWh and likewise influence the average cost of generation. Standby reserves might be reduced to the danger point - a situation giving rise to an economic cost. This may never be included in the calculations, as it is relatively insignificant. In addition to this, the quality of service is likely to deteriorate through voltage and/or frequency drops (Bonbright *et al.* 1988:420), which might be very costly.

Mostly, only the first element of short run marginal cost of service produced by an overworked plant can be expressed in terms of c/kWh. This might be a partial explanation of the results of a number of empirical studies (reviewed, e.g. in Mansfield, 1985: Chapter 7 and Johnson, 1960:44-73), which show a horizontal (constant) short run marginal cost curve for a given plant. Another reason for the observed horizontal unit cost schedules may be the paucity of data on the operating costs of the plant that was being pushed close to upper limits of their capacity (Bonbright *et al.* 1988: 420). Mansfield (1985:223) has a comprehensive discussion on the various limitations and concludes, "although short run marginal costs may well be relatively constant over a wide range, it is inconceivable that costs do not eventually increase with increases in output".

This is exactly the situation in Eskom, as excess generating capacity exists in the form of base load power stations. With a good load factor, marginal cost of service may be a mere fraction of average cost, but should the output increase to a rate slightly in excess of what existing capacity is safely adequate to supply, marginal cost will jump to some multiple of average costs and long run marginal cost.

Although from arguments by Bonbright *et al.* (1988:422-424) one may conclude all production cost of utility service must be deemed variable in the long run, it by no means necessarily follows that all these costs vary with change in rates of output, measured in the same units, along one single dimension. Bonbright *et al.* (1988:458) continues to argue that, to any clearly and permanently *off-peak service*, the only analysis applicable is the short run analysis. No component of plant capacity cost or capital cost should be included in the estimate of marginal cost of service.

On the other hand, as to the *peak hours service*, there is a significant distinction between short run marginal and long run marginal cost (Bonbright *et al*. 1988:458). Long run marginal cost of service supplied at times of system peak will include full allowance for increments in capacity. Cost may thus be warranted, in order to add to the supply of this type of service.

2.2 ANALYSING ESKOM'S COST

2.2.1 Current situation

Traditionally, Eskom believed that customers needed to be supplied with whatever amount of electric power they desire to purchase, whenever they require it. With the increases in system operating cost and plant construction cost, however, Eskom started to offer incentives to customers for controlling their rate of consumption during periods of system constraints. Still, at present, the static nature of all Eskom's electricity tariffs limits the degree to which customers can participate in supply side management. This leaves Eskom with an increasingly more and more peaky national profile, which is costing more and more to meet each year, whilst customers spend millions to satisfy tariff conditions that do not necessarily reflect the dynamic status of Eskom's system or the dilemma with which Eskom sits.

This derives in two options:

1. either Eskom meets the demand by running more base load stations sub-optimal or constructs and employs more peak demand stations (SSM); or
2. Eskom enters into a joint venture with industry to counteract the increasingly peakier load profile (DSM).

Roos (1996:96) listed the global objectives of utilities as summarised by Limaye (1985:1503-1511) to be:

- reduce capital requirements,
- improve financial performance,
- increase system performance,
- improve customer relations,
- reduce the use of critical fuels, and
- conserve energy.

In order for a utility to *reduce its capital requirements*, it should strive to minimise or defer the building of new power stations and transmission lines (Roos, 1996:96). Currently, the general view in Eskom is that generating capacity is not an immediate limitation but, in actual fact, most of the generation plant used for peak generation or standby capacity is more suitable for base load than for peak demand supply. As the national profile becomes peakier (to be discussed in detail in Chapter 3), the situation will further deteriorate. This leaves Eskom with the two options discussed earlier: either to increase peak generating capacity or to utilise the ability of industry to create a virtual peaking power station through load shifting. The most cost-effective way to deal with the latter option is to provide efficient pricing signals to customers to promote DSM. Best results will of course be realised if this can be done on a real time basis.

The *financial performance* can be *improved* by means of cost-reflective rates and by avoiding the operation of more costly generating equipment. Consumers should provide for the peak hours where expensive peaking power plants would have been scheduled and/or base load plant would have to be run at low load profiles.

Various growth opportunities exist in Eskom's off-peak periods, and tariffs should allow customers to make use of these opportunities. This will increase the system load factor and utilisation of the system (Roos, 1996:97). The rest of the utility's global objectives will be reached much easier once these first two objectives are accomplished.

Eskom currently has surplus energy that is a direct result of predictions of growth in South Africa during the late 70s to the order of 6% per annum. Building of base load power stations was commenced early, as it can take up to 21 years to add additional capacity to the system. To date, the predicted growth has not materialised, and Eskom has embarked on a massive electrification programme. It is from this angle that some argue that Eskom has surplus capacity, and this poses the question of whether there are any savings regarding the deferral of fixed cost in the clamping of peak demand consumption for the time being.

At present, peaking power on the Eskom system is generated by two pump storage stations (4.5% of installed system capacity), two hydro stations (1.7%), gas turbine plant (1.1%) and to some extent by older, less efficient and more costly coal-fired power stations (Calitz *et al.* 1990:16). This leaves more than 92% of the system load to be supplied by base load coal-fired stations. This situation will be discussed in more detail in chapter 3.

2.2.2 Cost reflective pricing

As mentioned earlier, a utility should strive to price electricity as cost reflectively as possible. Time-of-Use (TOU) pricing is one such instrument through which marginal cost pricing can be implemented (Bonbright *et al.* 1988:416) since costs vary by the season and by the time of day that the service is rendered. However, the practice of TOU pricing is only partly cost reflective, because the TOU pricing signals are still static and rather follow the LRMC of generation than the SRMC.

The proposed RTP tariff offers a methodology that might fill the gap. RTP can be viewed as the ultimate in short run marginal cost based pricing (Roos, 1996:39). Advantages of RTP, listed by Caramanis *et al.* (1982:3234), include:

- a high annual load factor,
- a lower frequency of involuntary blackouts,
- less oil and natural gas consumption for starting of plant,
- a higher percentage of base load units (high capital cost; low operational cost),

- a higher level of customer profits, and
- higher customer investment in electricity demand shifting equipment.

To date much is reported on the amount of money RTP is saving customers (Roos, 1996:40-65; Daryanian *et al.* 1991:1356-1365; Daryanian & Bohn, 1993:35-43 and more, plus various internal reports in Eskom). Hence, not much has been done to determine to what extent the utility benefits from RTP, or whether it does at all. It is generally assumed that the utility will save money with every kWh of electricity that is shifted from peak to non-peak hours, but this has never been quantified to an acceptable extent in any utility, including Eskom.

Two schools of thought exist in Eskom in this regard, namely:

1. a planning approach based on calculations normally used to determine whether new generating plant needs to be planned and constructed, and
2. a view based on actual scheduling of generating plant, to meet the predicted load profile for the next day.

Arguments for and against each view exist in Eskom and both will be discussed in more detail below. In chapter 3, both schools of thought will be used to determine the cost saving Eskom might encounter through DSM, if offering RTP to its customers. The SRMC as well as LRMC savings will be explored under each method. In this way it is intended to answer the primary objective of this dissertation - "*to investigate the potential of the proposed RTP tariff as a Demand Side Management (DSM) option in Eskom*".

2.2.3 First school of thought

This view of determining marginal costs assumes a smooth, average type of load profile with average associated cost of generation. It is based on a planning approach, and is normally used to determine whether or not new power stations need to be constructed. This is the method used by Eskom's long-term forecasters and the most commonly used method throughout utilities.

Marginal costs are calculated for a 500 MW movement in load, applied to a base load plan and set to meet a particular load forecast and annual growth in demand. This can be done over any planning horizon for which relatively accurate assumption and estimates can be made. Incremental costs are then attached to the load profile as anticipated for the future (Mthombeni, 1997:1).

A cost component for unserved energy is added in periods where peak demand is anticipated, depending on the amount and type of generating units available. As the anticipated load profile changes, a cost component for risk and uncertainty, regarding the ability of the utility to meet the demand, is also added. Thus, the higher the degree of risk and uncertainty, the higher the required rate of return. This uncertainty and risk emerge from the lack of definite knowledge and assumptions, which may impact the project (Mthombeni, 1997:4).

The major components of costs are derived from:

- the cost of coal delivered to the coal-fired power stations and/or other fuel used to generate power,
- the cost of operating and maintaining the power stations, and
- disconnected capital cost incurred.

2.2.4 Second school of thought

This school of thought reasons that it is impossible that the cost of generation can be a smooth curve that increases gradually as demand increases and available capacity decreases. Wood and Wollenberg (1984:6-7) plot cost versus output of a generating unit as a converse curve with an incremental step regarding inherent cost and fuel cost of start-up (C(s/u)). A similar curve is shown in figure 2.1.

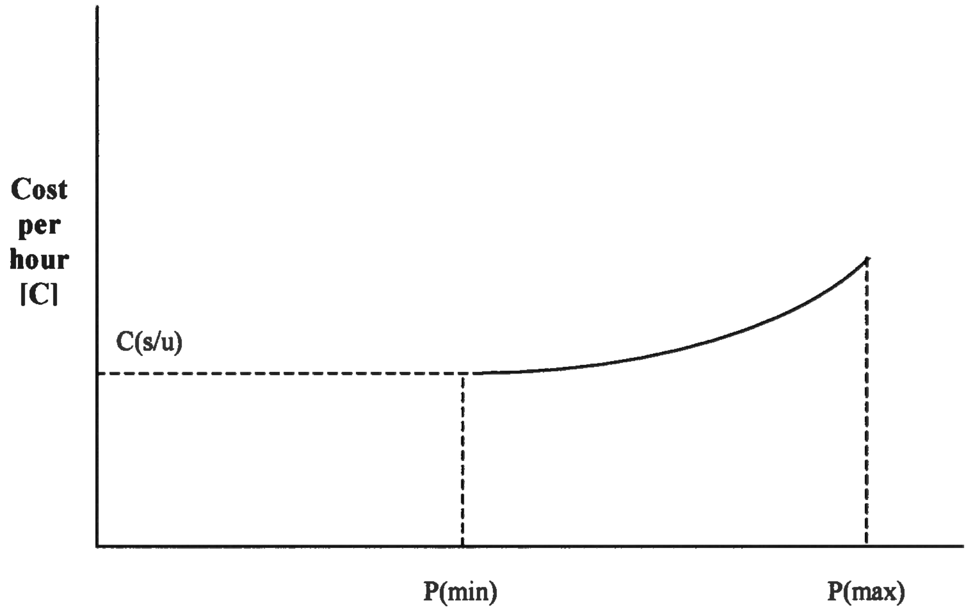

Figure 2.1 *A typical cost/input versus output curve for a steam generator unit (Wood and Wollenberg (1984:7))*

Steam turbines have a minimum load at which they can operate, normally caused by fuel combustion stability and inherent steam generator design constraints (Wood & Wollenberg, 1984:7). This results in incremental step changes in cost and standby/ available capacity, once an additional unit is started. It is thus believed that, to be able to know exactly what amount of costs is deferred/incurred by a specific kWh, one should know what was the system demand, and how the generators were scheduled for that hour. It might theoretically happen that the first 100 kWhs cost X c/kWh to generate, whilst the next kWh costs 2X, due to the start-up of the next generating unit that is required to supply that additional unit. Short run marginal cost and long run marginal cost are thus accounted for per kWh, in this school of thought, whereas in the first school of thought costs are "averaged out" to give a more smooth cost curve.

Wood and Wollenberg (1984:149-150) eventually draw the conclusion that unit commitment is crucial in bringing down the total marginal running cost. This ties up with earlier discussions and the opinion of Bonbright *et al.* (1988:462) that short run marginal cost becomes a fraction of total average marginal cost once a unit is running. If, however, the additional kWh calls for an additional unit to be started, marginal cost increases dramatically due to the short run marginal cost component.

This is aggravated by the fact that thermal units (like most base load units in Eskom) can undergo only gradual temperature changes. This translates into a time period of some hours required to bring the unit on line (Wood & Wollenberg, 1984:116-117), which leads to various constraints such as:

- *Minimum Up Time:* Minimum running time before being allowed to be turned off again,
- *Minimum Down Time:* Minimum time from decommitment to recommitment, and
- *Crew constraints:* If a plant consists of two or more units, they cannot be turned on at the same time.

Furthermore, because the temperature and pressure of the thermal unit must be moved slowly, an amount of energy must be expanded to bring the unit on line. This energy does not result in any MW generation from the unit, and is brought in as start-up cost. Other costs are also involved in generation and will, for the purpose of this study, not be discussed any further. Eskom's cost per unit and per power station can be seen in chapter 3 (Table 3.1).

One other factor that needs to be kept in mind is that adequate spinning reserve needs to be allowed on the system. Spinning reserve must be carried so that the loss of one or more units does not cause too far a drop in system frequency. Quite simply, if one unit is lost, there must be ample reserve on the other units to make up for the loss in a specific time period (Wood & Wollenberg, 1984:115). Beyond spinning reserve, the unit commitment problem may involve various classes of "scheduled reserves" or "off-line reserves". These include quick start diesel or gas turbines (Wood & Wollenberg, 1984:119). As such, most hydro and pump storage hydro units can be counted in the overall reserve assessment as long as their time to come up to full capacity is taken into account.

2.3 DEFERRED CAPITAL/FIXED COST

The ability to shift peak demand continuously to off-peak hours can result in the deferral of new power stations and ensure better utilisation of base load units. Costs can be saved through both these actions and can be accomplished by Intelligent Demand Side Management (Roos, 1996:39). The most crucial element in calculating the savings from deferred capacity expansion, that is often neglected, is to determine what you are deferring (Chan *et al.* 1980:54).

The current composition of generating plant must be researched to link the ability and applicability of existing plant to the ultimately required plant to meet the load profile. If the available plant can meet the current load profile in an acceptable manner, no need exists for additional plant. If, however, the existing plant needs to be scheduled in a sub-optimal way (i.e. base load plant needs to be scheduled to meet short-term peak demand) the need for additional plant already exists. Looking at the future expected load profile, the same criteria can be applied in comparing the expected profile with the plant available for scheduling. In this way, it is possible to determine at what date additional generating plant will be needed. If the profile is adjusted in acceptable blocks of time, one finds the optimal time to add new plant.

For this exercise, the same load profile to be used in the second school of thought to determine the cost of generation per unit, can be used. One might find that the so-called surplus capacity in Eskom's generation plant soon becomes very inefficient in meeting the current and future load profiles. The cost of constructing the most desirable plant that will assist existing plant to meet future profiles should now be compared with the cost of running the "inefficient" plant. Only if the cost of running the "inefficient" plant exceeds the cost of building the desired plant, it can be taken that shifting load to avoid building additional plant will result in the deferrence of capital. This can also be taken as the earliest date from which savings can be realised in terms of fixed costs.

On the other hand, care should be taken that too much capacity is not committed at any time of the day; meaning that, if all units are running at their minimum allowable output, the load connected to the system at that specific time or hour, should not be less than the total output of all running plant. This stresses the point that cognisance should be taken about the total load profile and the characteristics of all plant that is scheduled. It might be found that unscheduled coal-fired stations have a very low average running cost per unit if used for base load generation, but once they are used to provide only for peak hours, the indirect cost, or the cost per required hours, multiplies.

It is fairly easy to determine the period for which the discounted benefit to the utility will last, once the type of plant required to meet the additional demand economically has been selected, the cost of constructing such plant has been determined and the load profile has been adjusted with the amount of load that can be shifted from peak demand hours.

One of the best ways of calculating the benefit to the utility will be to apply the General Valuation Model of discounting as described by Brigham and Gapenski (1994:276). Discounting is, in laymen's terms, the process of finding the present value of a future amount. In general, the present value of a cash flow due in ***n*** years in the future is the amount, which, if it were on hand today, would grow to equal the future amount (Brigham & Gapenski, 1994:231). Chapter 3 will elaborate on the issue of deferment of capital cost in Eskom.

CHAPTER 3: DETERMINING ESKOM'S RUNNING COST

3.1 Introduction

Following from chapter 2, one might consider the marginal running cost (short- and long-term) to be the only cost that will substantially vary as consumption patterns vary. Thus, to be able to determine whether any load profile shaping or management of load patterns will benefit Eskom, one should look at the impact such DSM has on Eskom's SRMC and LRMC.

Currently, two schools of thought exist (as been discussed in paragraphs 2.2.3 and 2.2.4) through which these costs can be determined and both will be used to estimate the SRMC and LRMC, or savings that might be realised through RTP.

3.2 First school of thought – averaged running cost

Summarising paragraph 2.2.3 from chapter 2, this school of thought argues that it is accurate enough to say that cost changes smoothly as demand varies. This principle applied, figure 3.1 illustrates how Eskom's hourly marginal running cost differs from hour to hour throughout a typical winter day and/or week, according to Eskom's Integrated Electricity Planning. Figure 3.2 illustrates how these costs will increase over the next 20 years. Marginal cost will increase unevenly between hours over the next 20 years, as Eskom runs out of capacity. This also is a function of the sub-optimal mix of generating plant in South Africa. Peak-demand increases at a higher rate than demand in other hours of the day, as been discussed in chapter 1 – hence, the uneven increase in hourly marginal cost over the next 20 years, as per the graph in figure 3.2.

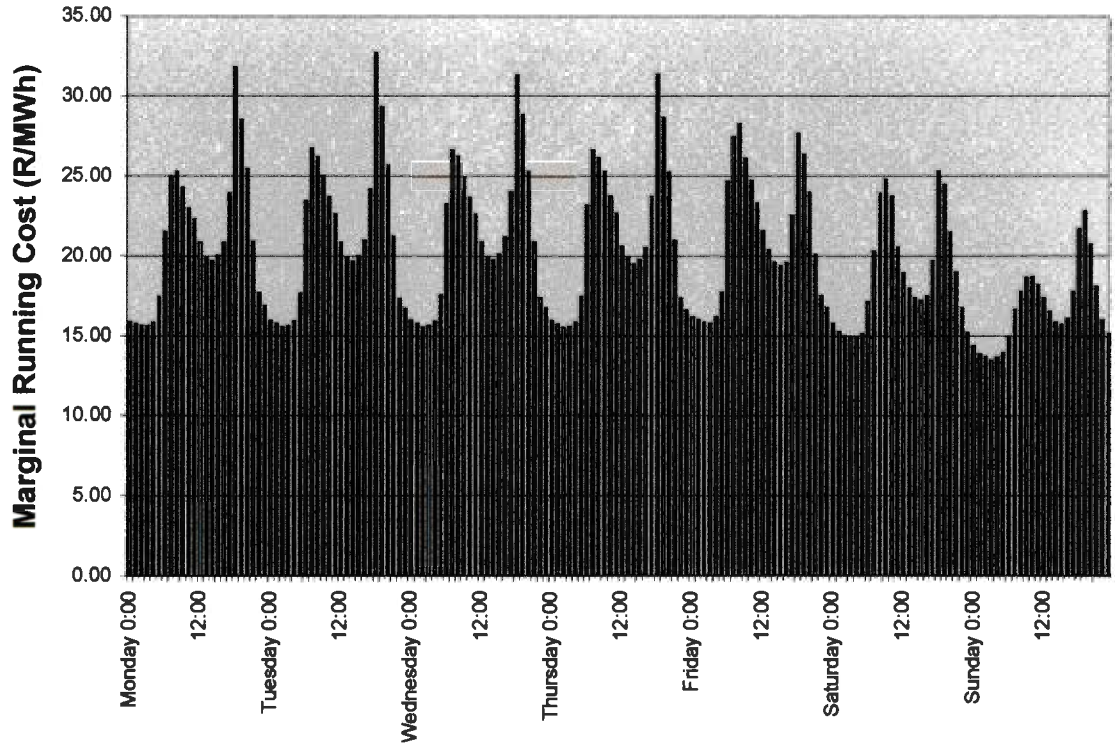

Figure 3.1 *Eskom's current hourly marginal running cost for an average week*

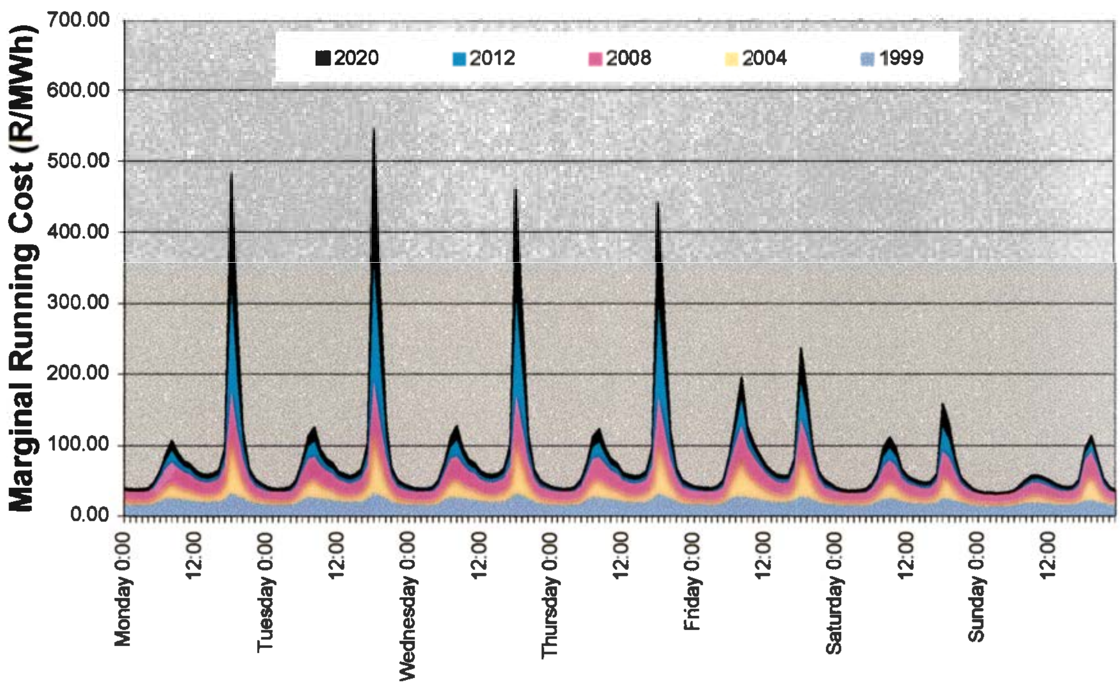

Figure 3.2 *Estimated increase in marginal running cost*

(IEP Vol.7, 1998:13, both figures 3.1 & 3.2)

This school of thought makes use of averaged costs and does not take into account short-term network conditions. Nevertheless, it provides a fair indication of the cost to generate electricity in a specific market. As been discussed in Chapter 1, South Africa's growing domestic market has a significant influence on the cost of generation, causing the marginal cost to increase dramatically during hours that peak domestic demand occurs. During the later 90s, and even more so before Eskom's electrification drive started in 1994, the percentage of energy been taken by industry versus domestic was in the order of 20:1 (IEP 7:1999,5). The latest forecasts suggest a decrease in the ratio, with an inevitable negative influence on the marginal cost of generation during those hours of peak domestic consumption. This is reflected in Figure 3.2, showing that the anticipated marginal cost of Eskom will increase unevenly throughout the day.

To understand better how these costs are derived, one needs to unpack the cost and, for the purpose of this dissertation, it will be subdivided into SRMC and LRMC. Both these costs have been discussed in great detail in chapter 2, but in short they can be described as the cost for operations and maintenance (SRMC) and the cost to provide capacity and keeping it up-dated (LRMC). LRMC thus relates more to capital and finance costs, whereas SRMC represents the day-to-day running costs.

3.2.1 Short run marginal cost (SRMC)

Figure 3.3 (a) and (b) show Eskom's averaged SRMC per unit of electricity, as having been constructed from information been received from Eskom's Integrated Electricity Planning department. The graph in Figure 3.3 (a) shows how the SRMC is estimated to increase in different hours. One can see that this cost increases more during the afternoon (domestic peak hours) than during other hours. It even decreases during night-time (off-peak hours) in later years, while it increases in peak hours for the same year. These uneven and time differentiated increases in SRMC are due to more expensive base load plant and peaking plant that need to be started to cover the short-term peak demand.

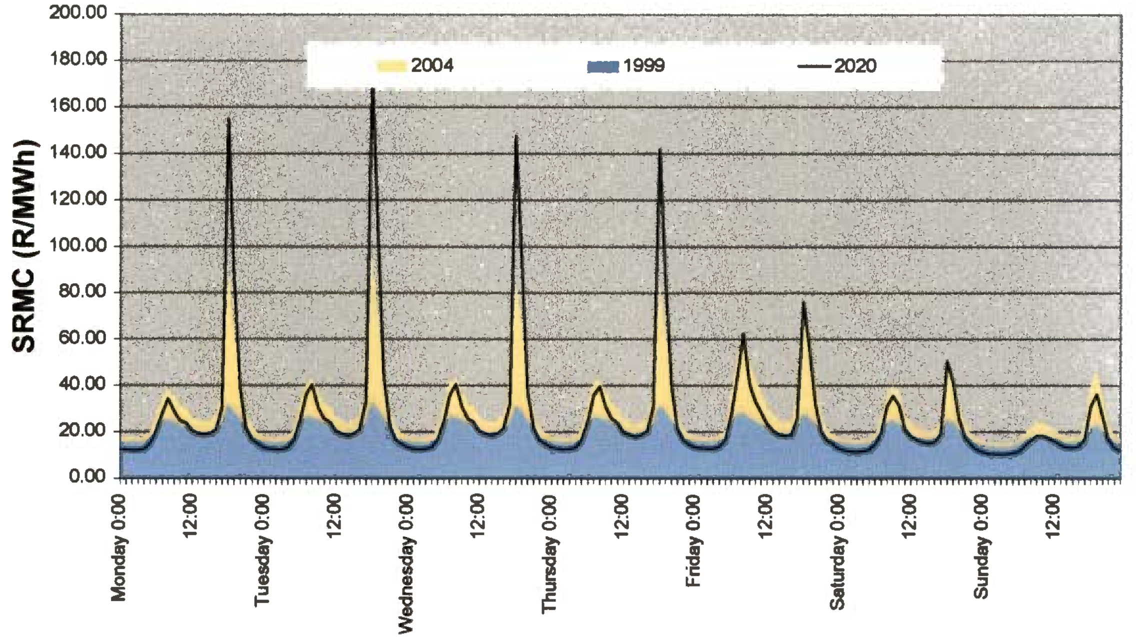

Figure 3.3 (a) *Eskom's anticipated SRMC for an average week, for coming years*

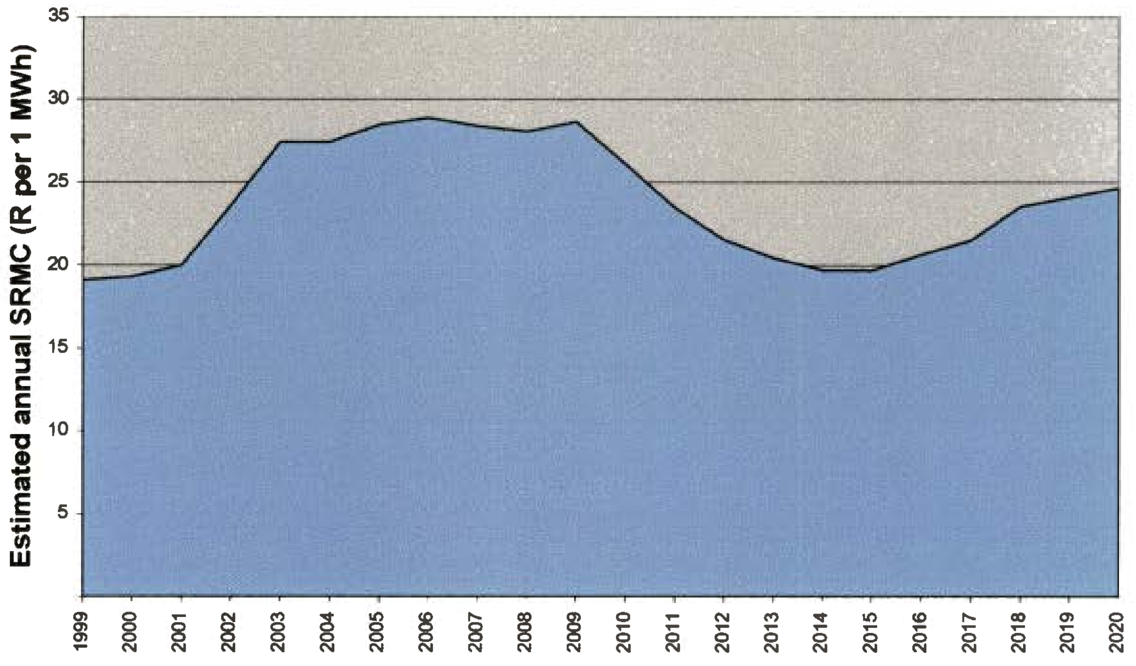

Figure 3.3 (b) *Eskom's anticipated averaged SRMC for selective years*

Figure 3.3 (b) explains this phenomenon better by showing that the average yearly SRMC per 1 MWh increases dramatically from 2002 till 2004, which is mainly due to sub-optimal scheduling of existing base load plant, which has to fulfil the job of peaking plant. Once Eskom's mothballed power stations are brought back into service as from 2004 till 2009, the SRMC stabilises, but one can anticipate the LRMC to start increasing due to spending of capital. By 2009, it is anticipated that new peaking plant has to be built, which of course will bring down SRMC due to the ability to schedule more optimally. Again one can anticipate LRMC to start increasing, but more will be said about LRMC in paragraph 3.1.2.

The aim of RTP thus should be to move load from those hours with high SRMC to hours with a lower SRMC, to avoid Eskom having to increase generation during peak hours, as is anticipated in Eskom's IEP plans and is discussed above. Figure 3.4 shows the estimated annual savings to be realised if RTP can manage 100 MW of load shifting from these high cost hours. Accumulative, over the next 20 years, these savings amount to R35.7 million, or R9.4 million in 2000 rand value.

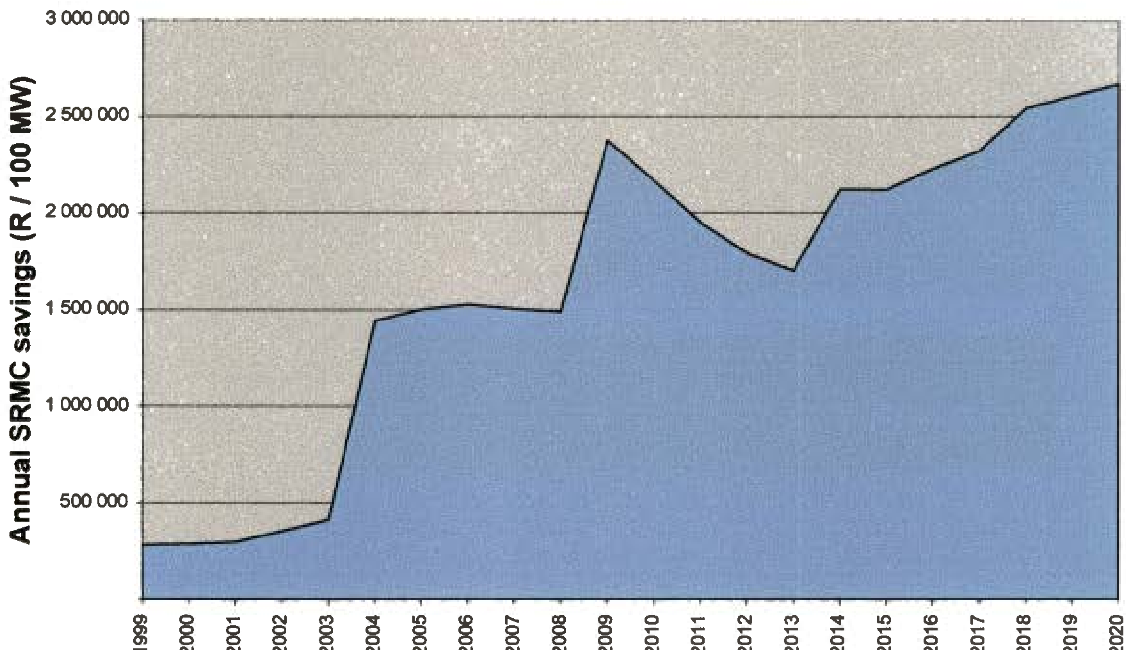

Figure 3.4 *Anticipated annual SRMC savings to be realised through 100 MW load shift*

3.2.2 Long run marginal cost (LRMC)

As discussed, LRMC comes into play once a utility believes it is unable to meet the predicted national demand and starts to spend capital to ensure the ability to do so. Figure 3.5, also adopted from Eskom's IEP 7 plan, shows the time by which national demand for electricity will outgrow the available generating capacity, in terms of highest registered demand per year. It substantiates the reasons given in paragraph 3.1.1 for the variance in SRMC, which is a function of the mix of plant available to be scheduled. As has been indicated by the dotted line, Eskom most probably will run out of capacity by 2003/4. At that stage mothballed power stations will be brought back into service at relatively small capital cost. If, however, demand continues to increase, new peaking plant needs to be constructed by the year 2008/9, to cover the growing peaks in domestic demand.

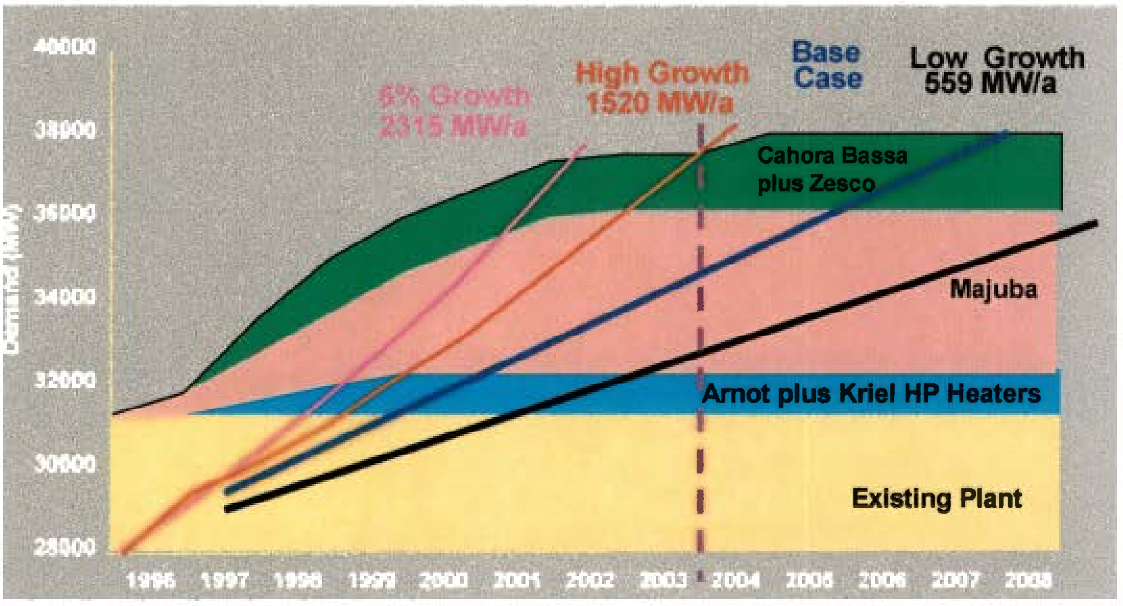

Figure 3.5 *Eskom's anticipated load growth versus its generating capacity (Eskom's Integrated Electricity Plan, IEP 7, 1999)*

Similarly as with SRMC, the annual LRMC associated with 100 MW additional generation can be determined and is shown in figure 3.6. Unlike SRMC, the LRMC simply increases every year, as more expensive alternatives need to be used. If this can be deferred by RTP for one year, the value of such an action can be calculated through discounting the costs over a given time. As has been discussed in paragraph 2.3 of chapter 2, the general valuation model of discounting will be used to determine what the real value of such DSM effort would be in 2004. It can be further discounted to 2000 values, but since Eskom rightly argues that deferment of capital has no value to its current operations, the values will only be discounted to 2004 when capital actually needs to be spent.

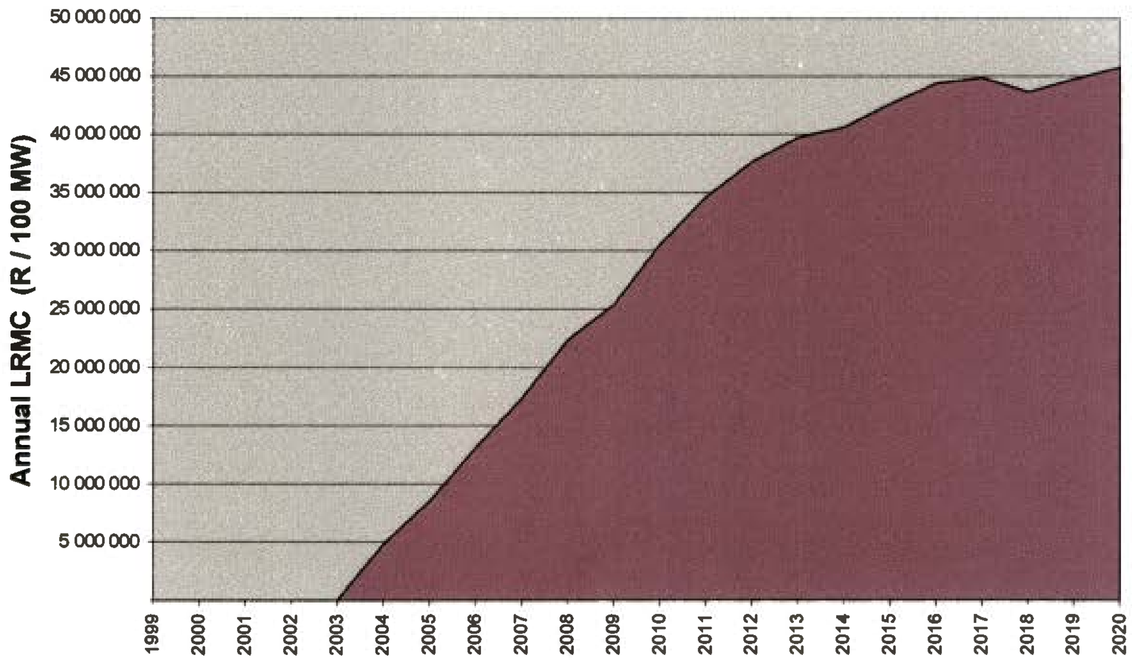

Figure 3.6 *Yearly LRMC savings if 100MW can be shifted from peak hours*

Figure 3.5 indicates that, for a high growth scenario, the national demand for electricity will increase by 1 520 MW in 2004, whilst for a low growth scenario it will grow only by 559 MW. Taking the low growth scenario, any load shift up to 559 MW will defer capital for one year by 2004. Eskom discounts all capital at 11% and, if a 100 MW block of load is considered, the discounted value of the deferment of capital amounts to R25.8 million in 2004 rand terms.

3.3 Second school of thought – hour-specific running cost

In chapter 2, paragraph 2.2.4, a second school of thought was introduced, which in essence argues that it is grossly inaccurate to use average running cost to calculate the benefit of a dynamic tariff. It argues that DSM is an hour-specific action in reaction to a specific signal from the utility, and the exact hour's cost to the utility needs to be used in calculating the net effect of the DSM effort. For static tariffs one might still get fair answers by using the first school of thought, but for a dynamic tariff like RTP, the signal from the utility that initiates specific DSM reaction is based on an hour-specific situation. The hour-specific cost must therefor be considered in the cost analysis.

3.3.1 Short run marginal cost (SRMC)

The concept of costing the last unit to be generated in any hour was explained in great detail in chapter 2 and will be used to determine the real SRMC benefit of RTP. It is of course impossible to use a whole year's actual data in an analysis like this and, therefore, only results from a 21-day period in 1998 will be used. Table 3.1 gives actual costs, as well as other important detail of Eskom's generating plant. From the table, one can read that Koeberg power station, for instance, has 2 units of 890 MW each that need to be run at 100% of their capacity for 24 hours a day, every day. Koeberg's fuel cost is R 21.57 per MWh and operations and maintenance cost (O & M cost) is R 5.00 per MWh. The maximum capacity of the power station thus is 1780 MW and the minimum is one unit, which is 890 MW. The last column simply gives the accumulative output for all the power stations.

Given then that Eskom has surplus generating capacity, Eskom was able to meet the predicted demand for the days under discussion as indicated in figure 3.7. The graph however also indicates sub-optimal scheduling, as been discussed in paragraph 2.2. From the graph it can be seen that the output of all base load units needed to be limited from time to time, to prevent the higher order scheduled base load units such as Arnot and Tutuka from tripping. The effect of limiting a power station's output is especially visible from Matimba's scheduling, which is pointed out by the red arrows in figure 3.7.

Station	Unit Size (MW)	No of units	Minimum Operating Load Factor (%)	Minimum on Time / day (Hours)	Fuel Cost (R/MWh)	Other	O & M Cost (R/MWh)	Total Cost (R/MWh)	Max. Capasity (MW)	Min. Running Capasity (MW)	Accum. Capasity (MW)
Koeberg	890	2	100%	24	21.57	Must Run	5.00	26.57	1780	890.0	1780
Hendrina	190	10	85%	24	17.24		5.00	22.24	1900	161.5	3680
Matla	585	6	75%	24	21.15		5.00	26.15	3510	438.8	7190
Matimba	612	6	75%	24	19.90		5.00	24.90	3672	459.0	10862
Lethabo	595	6	75%	24	22.54		5.00	27.54	3570	446.3	14432
Duvha	575	6	75%	24	20.91		5.00	25.91	3450	431.3	17882
Kriel	475	6	75%	24	22.64		5.00	27.64	2850	356.3	20732
Kendal	640	6	45%	24	24.31		5.00	29.31	3840	288.0	24572
Arnot	330	5	75%	24	29.06		5.00	34.06	1650	247.5	26222
Tutuka	585	6	75%	24	33.39		5.00	38.39	3510	438.8	29732
Majuba	615	4	60%	15	36.97	Two shifting	5.00	41.97	2460	369.0	32192
Gariep	90	4	70%	1	0.00	Limited energy	1.00	1.00	360	63.0	360
VDK	120	2	70%	1	0.00	Limited energy	1.00	1.00	240	84.0	600
D'Berg	250	4	70%	1	35.14	Limited energy	1.00	36.14	1000	175.0	1600
Palmiet	200	2	60%	1	36.30	Limited energy	1.00	37.30	400	120.0	2000
Gas Turbines	57	6	50%	1	600.00		5.00	605.00	342	28.5	2342

Table 3.1 *Detailed operational generating plant for 1998*

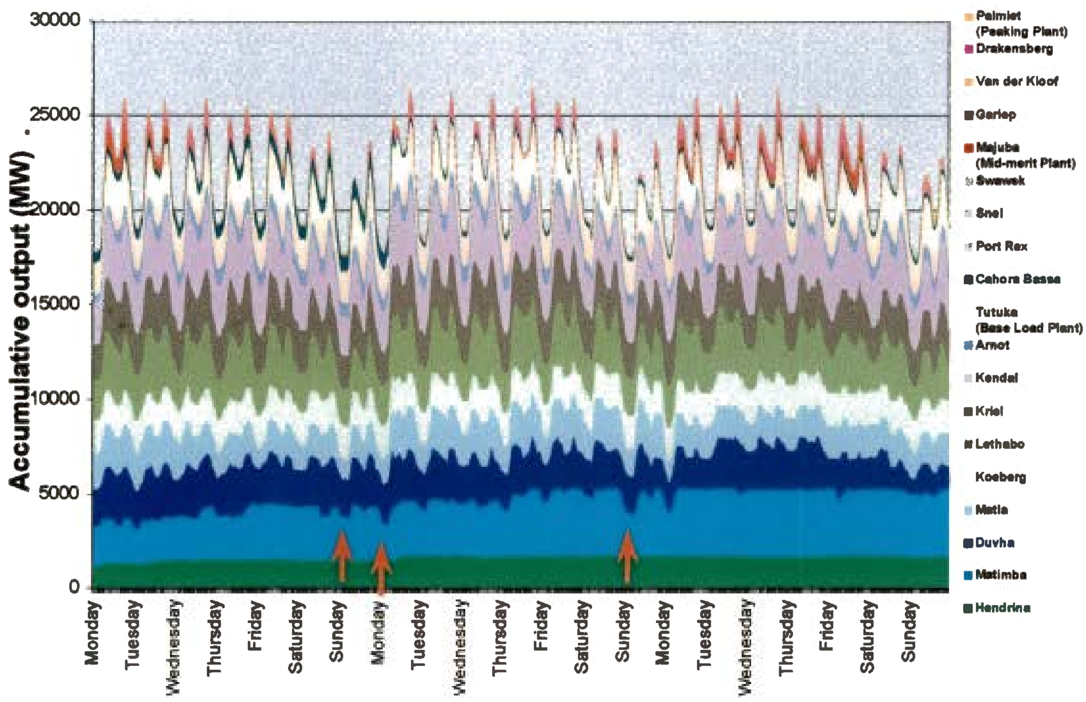

Figure 3.7 *Actual scheduling of generating units (29/6/98 – 17/7/98)*

Eskom's mix of generating plant and the limitations shown in table 3.1 are a given, and the only alternative to limiting generators' output, in an attempt to meet the national demand for all hours of the day, is to lower the daily maximum demand. Instead of building expensive peaking plant, the demand can be controlled by shifting peak hour consumption to off-peak hours. Figure 3.8 (a) shows surplus capacity that was available per power station, above the pre-set safe level of spinning reserves, whilst figure 3.8 (b) simply magnifies two of these days, to be able to understand more clearly the profile for the sake of the argument to follow. Figure 3.8 (b) also shows the national demand (national profile) registered during the two days (on the secondary y-axis).

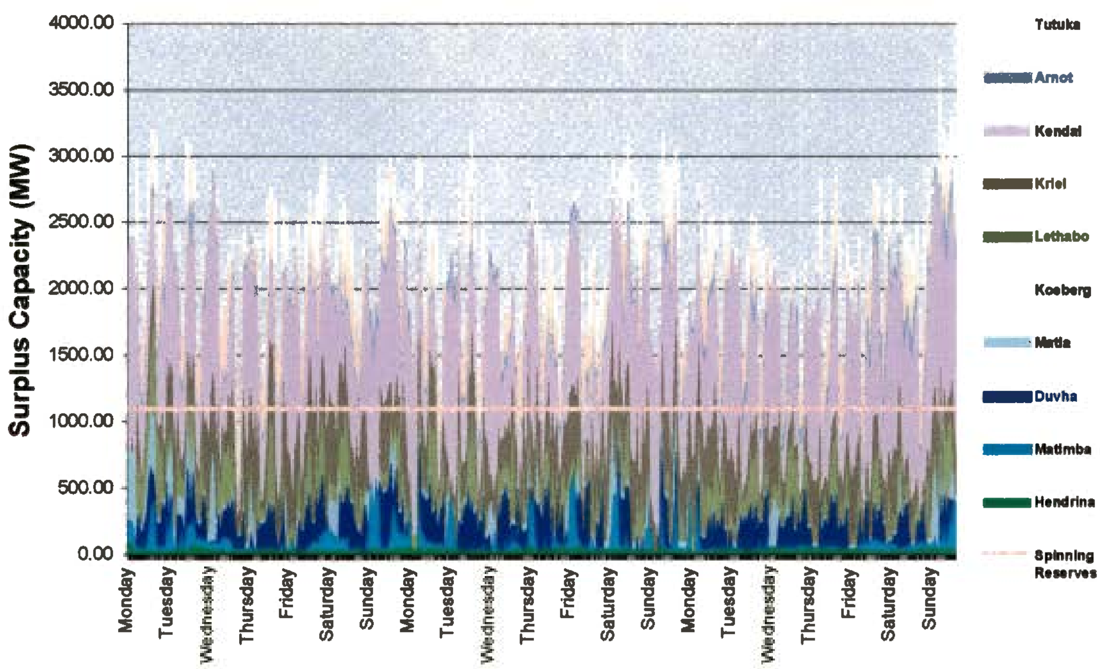

Figure 3.8 (a) *Surplus capacity per committed base load power station*

Figure 3.8 (b) shows those low-demand hours of the national profile coincide with the hours large volumes of surplus capacity are available on the system and vice versa. By controlling national demand in hours of little spare capacity and moving consumption towards the hours of surplus capacity, one evens out the demand on the units scheduled for the day. This will eliminates the need for generators to be cut back in certain hours to avoid tripping due to low loading. This concept was thoroughly discussed in paragraphs 2.1 and 2.2 of chapter 2.

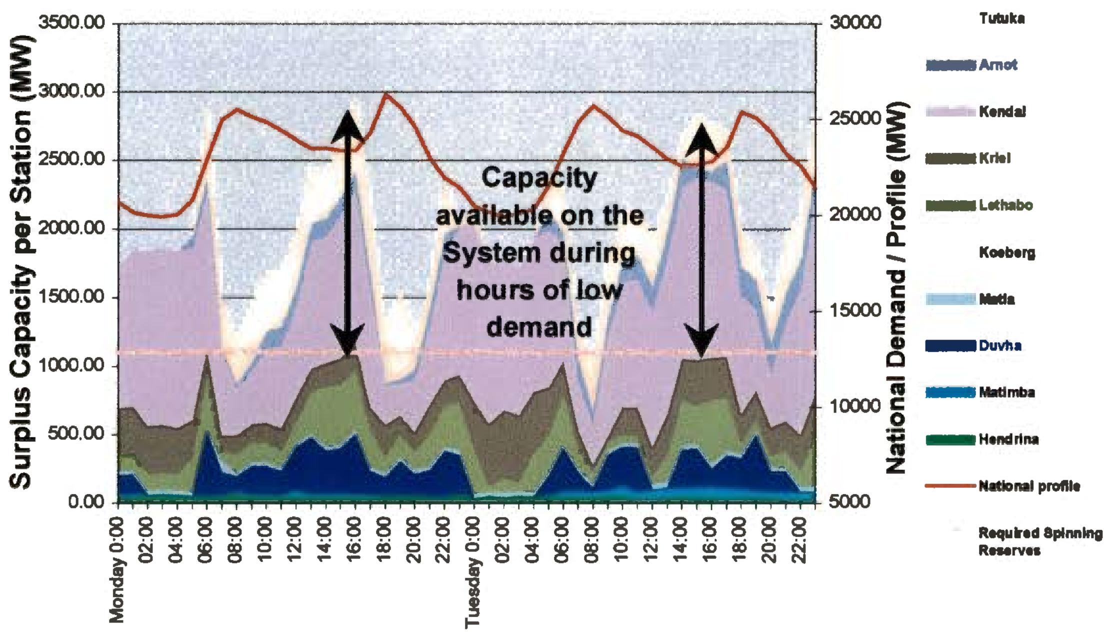

Figure 3.8 (b) *Surplus capacity per power station (two days)*

If one now considers a power station with smaller size generators, such as Kendal, and one assumes a tariff exists that can shift any amount of load from peak to off-peak hours as required to optimise scheduling, one can calculate the real time effect of load shifting. Figure 3.9 accordingly shows the actual commitment for Kendal power station for the period under discussion.

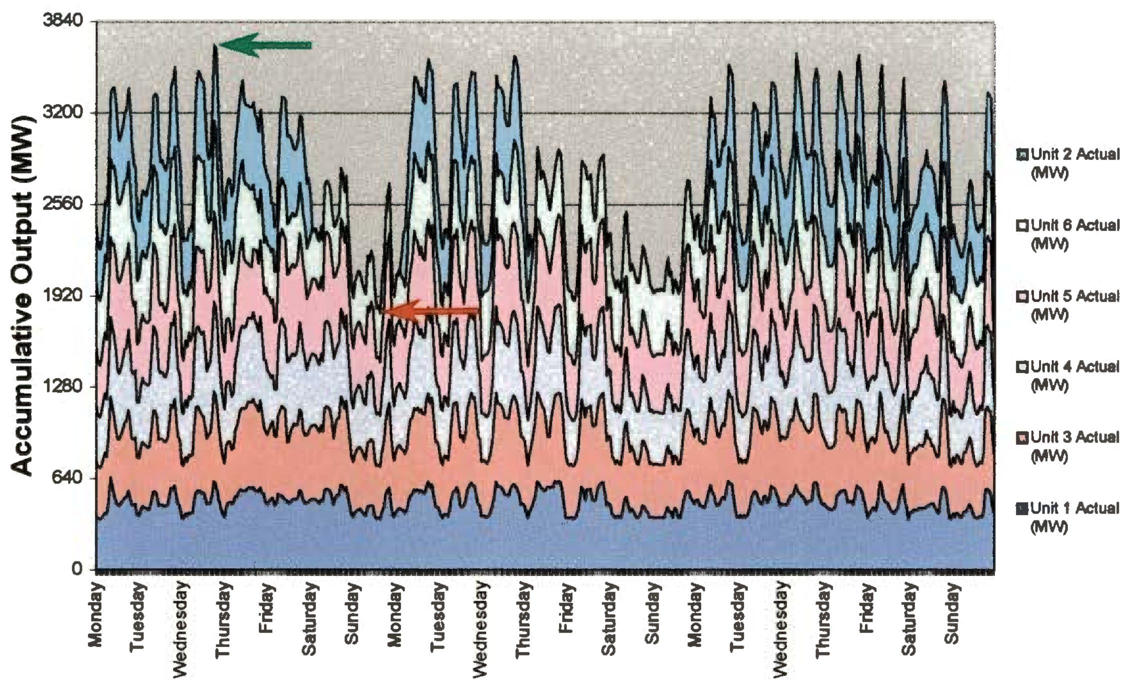

Figure 3.9 *Kendal power station – actual commitment per generator*

Kendal's unit sizes are 640 MW each and the minimum operating load factor is 84%. To be able to achieved the output required from the power station, loading on the units had to be altered and all units had to be cut back on a daily basis, as indicated in figure 3.9. The highest power swing for Kendal over any 24-hour period under review was recorded as 1669 MW, which is more than the output of two units. During the period under review, the number 2 unit needed to be shut down twice and be restarted again, due to the slightly longer-term fluctuation in demand and to avoid uncontrolled tripping of the units.

Whilst figure 3.9 shows the actual commitment of Kendal, figure 3.10 shows the total capacity that was committed at Kendal. From the two graphs, the following can be concluded: though the highest demand needed from Kendal was 3676 MW (Wednesday, 1 July 16:00 – indicated by the green arrow in figure 3.9), the available capacity at times was 3840 MW (figure 3.10, green arrow). Likewise the minimum capacity committed at any time during this period was 3200 MW (figure 3.10, red arrow), whilst the lowest actual demand was only 1798 MW (Sunday, 5 July 15:00 – figure 3.9, red arrow).

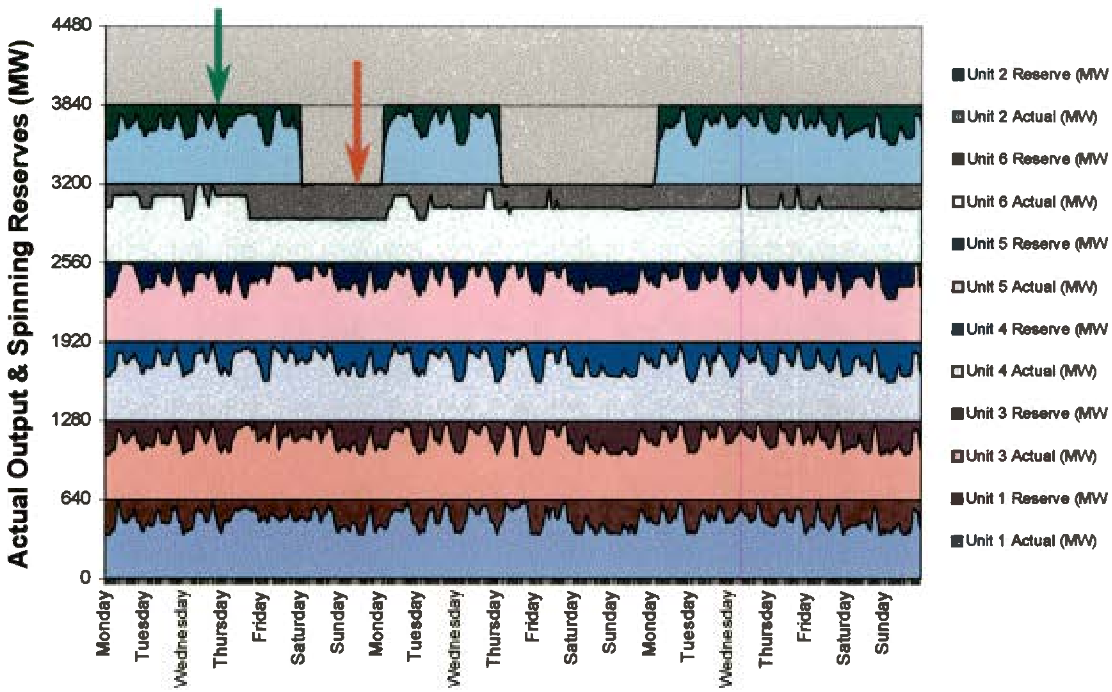

Figure 3.10 *Committed capacity at Kendal power station (actuals & reserves)*

The dilemma is that, if all units were not committed, the maximum required demand of 3676 MW as been requested from Kendal could not have been met. On the other hand, leaving all units running all the time would have created the inverse of the problem at times of low demand and some units would have tripped. The output of all committed units had to be altered and unit number 2 needed to be shut down twice to prevent uncontrolled tripping.

Should, however, one be able to control the demand to permanently stay under 3200 MW, the number 2 unit needs not be scheduled at all. This situation is shown in figure 3.11 where the total demand was controlled to 3200 MW and the units rescheduled to meet the remainder of the demand. It was now possible not to commit the number 2 unit of Kendal and still achieve the newly required demand pattern.

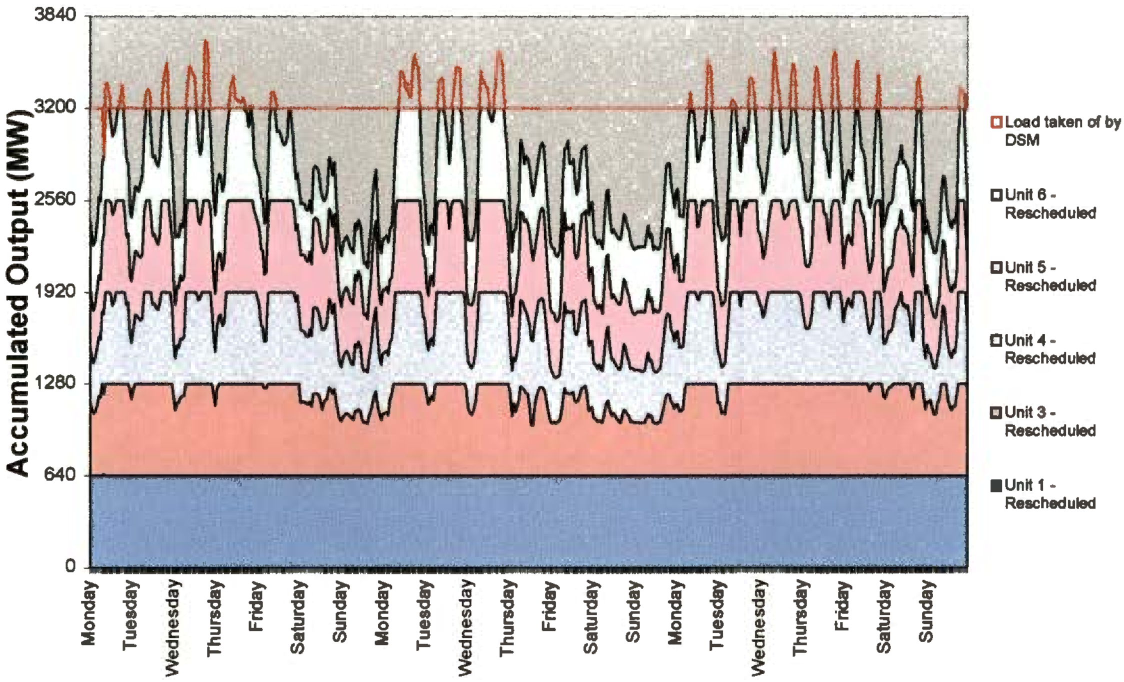

Figure 3.11 *More optimal scheduling of Kendal units with demand controlled at 3200 MW, through DSM*

Having shifted demand above 3 200 MW from hours of system peak and rescheduled the units of Kendal, one can calculate what this action would have saved Eskom. Figure 3.12 shows the demand having been cut over this three-week period under review to be able to reschedule the units and not commit unit 2. It also shows, on the secondary y-axis, the corresponding avoided hourly fuel costs. Detailed calculations on how the savings have been determined can again be seen in the attached electronic appendix B2.1. Savings achieved over the three-week period under review were linearly extrapolated to account for a period of one year and were calculated to be R 9.8 million per annum.

It is important to realised that, from figure 3.12, a minimum DSM potential of 474 MW should be available throughout the year to be shed in any hour it is required. The amount is not necessarily exact, for it may vary on a daily basis. The minimum amount required should be taken as the smallest generator that was committed for the day.

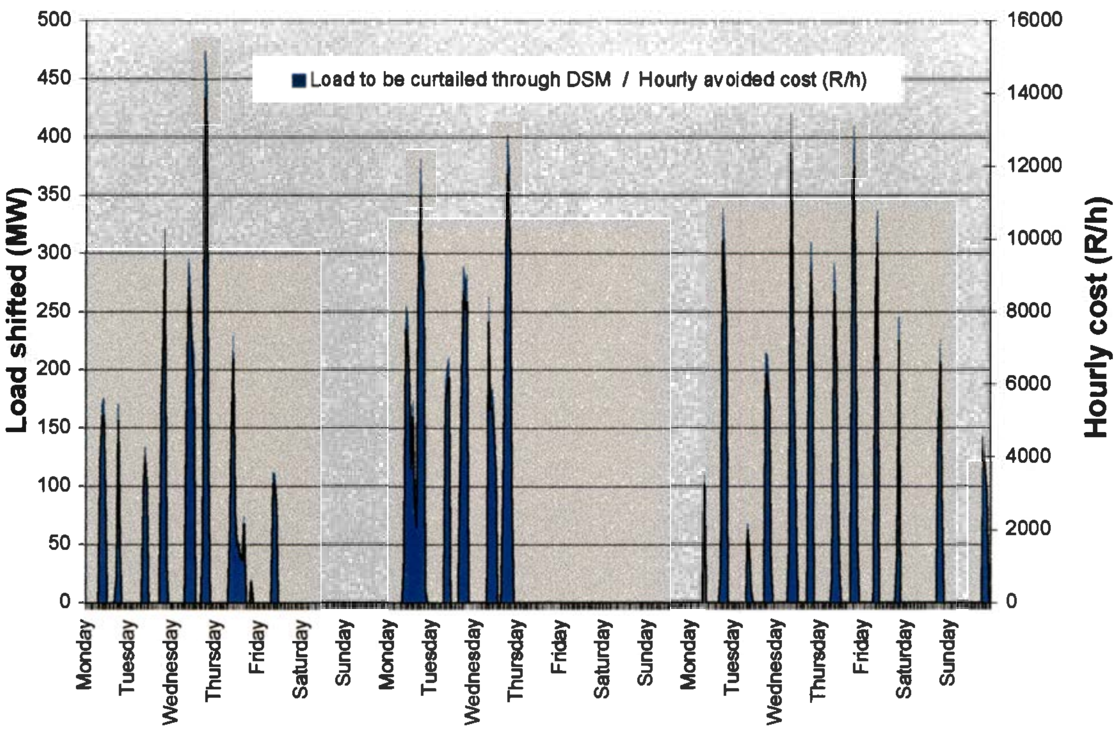

Figure 3.12 *Load to be shifted to be able not to commit Kendal number 2 unit, with the corresponding hourly avoided cost*

Currently payment to base load generators being scheduled gets done at the cost of the highest bidder for the day, meaning that, though Kendal's cost structure might remain the same over years, the increase in payments to Kendal may not be the same each year. One could thus expect the value of displacement of Kendal number 2 unit to increase as base load units get scheduled less optimally.

During the period mothballed power stations are being brought back into service, one would expect the value of the displacement to remain constant or drop slightly. Once a new peaking station gets commissioned and a base load station has been scheduled for the load it was designed for, one expects the value of displacement of any unit to come down. Payment and cost savings are thus a function of the mix and availability of plant.

To have been able to forecast the value of the displacement of Kendal's number 2 unit, the yearly increases in SRMC during off-peak hours, as per Eskom's IEP 7 plan, have been used. The value of the displacement in 1999 was thus inflated/deflated at the same rate the off-peak SRMC was forecasted to vary. Yearly savings to be achieved through this initiative are shown in figure 3.13. Over the next 20 years, it accumulates to R214.1 million. In 2000 rand value it would be worth R86,1 million.

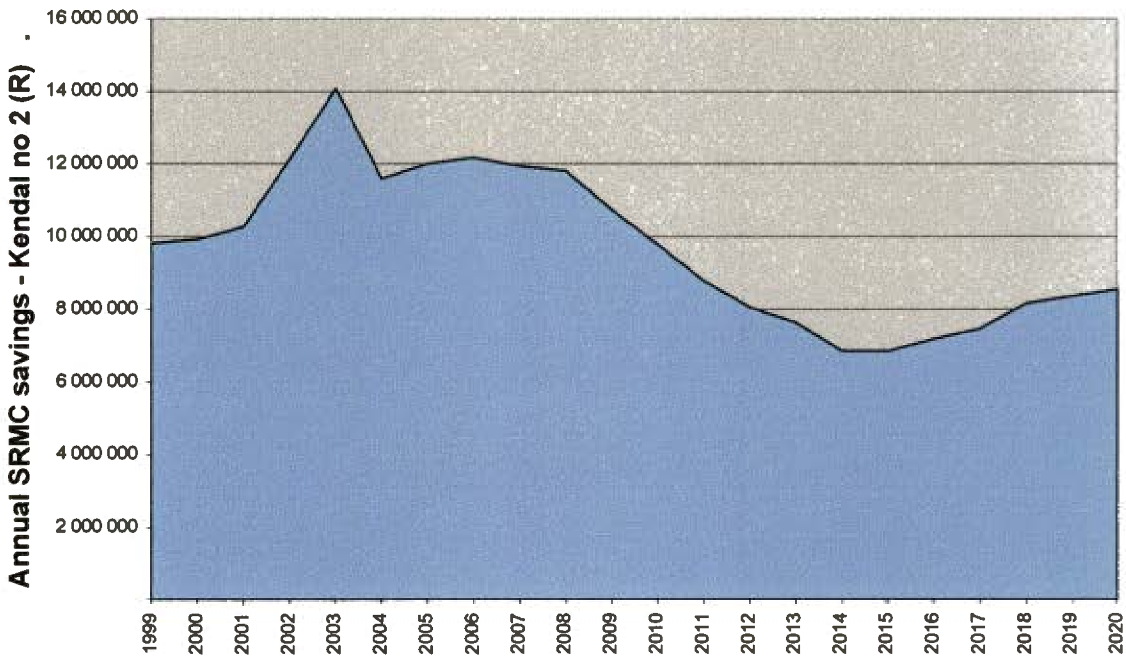

Figure 3.13 *SRMC savings if Kendal's number 2 unit needs not be scheduled*

3.3.2 Long run marginal cost (LRMC)

Having been able to displace Kendal's number 2 unit through RTP initiated DSM and still achieve the same output, means that the remainder of the units are being run more efficiently. The displaced unit will now be available for additional generation, which means capital expenditure to meet future demand is being deferred.

The latest indications are that constructing peaking plant will cost at least R860 per kW and gets built in blocks of 200 MW. The size of the unit being displaced is 640 MW, though it was actually displaced by shifting 474 MW from peak hours. This means that about 3 peaking units have been deferred. Given the growth in demand for electricity from figure 3.5, the deferral will help for one year only and LRMC savings only should be worked out for the deferral of 3 peaking units for a period of 1 year.

As been mentioned, Eskom discounts all capital at 11% and the cost of a 200 MW peaking plant is estimated to be at least R172 million in today's terms. The deferral thus amounts to a benefit of R69.9 million in 2004 rand value. Though costs will not all occur during one year, this will not be taken into account in this dissertation due to the uncertainty about such expenditure stream.

3.4 Summary of results

Table 3.2 summarises the results of sections 3.1 and 3.2 and gives the precise values of SRMC and LRMC savings as being suggested by the two schools of thought. The results will be further discussed and interpreted in chapter 5.

	SRMC savings [2000 values]	LRMC savings [2004 values]
First school of thought	R9 392 578	R25 789 540
Second school of thought	R86 154 841	R69 933 996

Table 3.2 *Savings to be achieved in SRMC and LRMC as per the two schools of thought*

CHAPTER 4: EMPERICAL STUDY – SURVEY ON RTP-DSM POTENTIAL IN SOUTH AFRICA

4.1 Introduction

In paragraphs 2.2.4 and 3.2 it was argued that the benefit Eskom might obtain from any DSM effort would be negligible unless a predetermined amount of load can be taken from the system at the right time of the day and for the full period the system is constrained. It is therefore essential to know whether or not the required amount of load to be shifted/ DSM in fact is available within the South African industry.

4.2 Methodology of survey

Determining the load shifting potential that might be realised within South African industry through dynamic pricing is not easy. Major consumers are used to the historic way of controlling load through demand control and do not easily realise the load shifting potential within their own plant under dynamic pricing conditions. Others believe that a dynamic, day-ahead tariff will not fit their industry at all. Customers are taught through years to control maximum demand and not energy usage, whilst short-term needs were mostly addressed by utilities themselves, through massive amounts of spinning reserves that were kept on the system.

This perception normally changes as one analyses customer's plant with them. It was accordingly decided not simply to send out questionnaires regarding load shifting potential under RTP conditions to be filled in by customers themselves. It has to be combined with either a visit or at least a telephonic interview. Experience taught that a personal visit results in the most reliable and useful information.

The methodology adopted thus was one of personal visits to explain the principles of RTP, followed by detailed discussions on the customer's plant and processes. During these discussions, specific processes that would be able to react to the RTP signal were pointed out. Examples of processes being used by other customers were also shared. Once the customer understood the principles of RTP and energy control versus demand control, the questionnaire was discussed and completed.

4.3 Limitations

Taking into account the cost of visiting customers and the time a presentation and an interview would take, it was decided to interview samples from targeted sectors only and extrapolate the results to get an indication for each specific sector. It was realised that the DSM potential might vastly differ between customers within a sector, in which case the sample was increased.

Given the mentioned constraints and the fact that the survey results themselves are mostly conservative estimates from customers on a tariff of which they have no experience, it is believed that the results are sufficient and representative enough to take a calculated decision. The intention was to get a fairly accurate indication of the potential for load shifting in South Africa, to be able to conclude the dissertation and to make a recommendation. The actual potential of industry will only be known once one or two customers per sector convert to RTP and actively exploit the tariff.

The survey was further limited to customers being fed directly from Eskom's grid, and those sectors that were willing to participate in the survey. Only two sectors were approached, namely the deep level mining sector and the smelting sector. From the customers' side, it sometimes involved the electrical- and production engineers and sometimes only the electrical people.

4.4 Survey results

Results of the survey are summarised in table 4.1 below, whilst an example of the survey form/questionnaire is attached as an appendix. From the results, it can be seen that the load shifting potential anticipated by the surveyed customers varies per customer and sector. This, of course, is directly related to the processes and capacity of each customer as well as the understanding of RTP and the benefits to be derived from exercising load shifting under RTP conditions. The potential in deep level gold mining, for instance, depends inter alia on the capacity of the underground dams, as pumping of water is their most controllable and flexible process. This will again be influenced by the influx of underground water at the time, as well as activities at the work face. It also depends on the depth of the mine, the method of mining and the amount of control to be exercised under RTP conditions.

The load shifting potential of the customers is captured against their registered maximum demand, from which a percentage load shifting versus maximum demand (% of MD) was calculated. This was done to get a common base to compare customers. Where the percentages within a sector varied significantly (such as in the deep level mining sector), the sample was increased to be able to obtain more representative results for that industry.

	QUESTIONAIRE				ESTIMATION OF SECTOR ABILITY		
SECTOR	No	Max Demand	Load shift potential	% of MD	Sector Max Demand	Load shifting ability	50%
Deep Level Mining	1	310	16	5.16%			
	2	66	6	9.09%			
	3	44	5	11.36%			
	4	23	3	13.04%			
	5	21	3	14.29%	3256	465	233
	6	70	18	25.71%			
	7	133	14	10.53%			
	8	210	30	14.29%			
	9	49	25	51.02%			
	10	89	25	28.09%			
Sub Total		**1015**	**145**	**14.29%**			
Smelters	1	294	80	27.21%			
	2	107	25	23.36%			
	3	110	90	81.82%	2750	1046	523
	4	54	20	37.04%			
Sub Total		**565**	**215**	**38.05%**			
TOTAL		**1580**	**360**	**22.8%**	**6006**	**1512**	**756**

Table 4.1 *Summary of the load shifting potential of industry in SA, to be realised through RTP (all values in MW)*

For each sector, the percentage load shifting versus maximum demand was calculated and linearly extrapolated to get the "load shifting ability" for that sector. Cognisance was taken of the fact that the complete sector will not go onto RTP, and a scaling factor of 50% was applied to the load shifting ability of each sector, to ensure results are somewhat conservative.

4.5 Conclusion from survey

Considering the complexity and inherent inaccuracies of any survey, but also the conservative approach adopted throughout this survey and calculations, it is believed that a larger sample would have made very little difference to the outcome of the survey and would not have been worth the cost. It is also believed that results obtained are sufficient to conclude that the load shifting/DSM potential in South Africa, under RTP conditions, will be enough to realise the required threshold on savings as was determined in paragraph 3.2.2.

Paragraph 3.2.2 required load shifting of at least the size of the smallest committed unit to be available (640 MW during the period under discussion), to be able to reschedule generators and realise the suggested savings. The survey revealed that 756 MW of load shifting is available in the deep level mining and smelter sectors. The potential also exists for extending RTP to other sectors that have not been surveyed, or to increase the percentage participation per sector.

CHAPTER 5: CONCLUSION AND RECOMMENDATION OF DISSERTATION

5.1 Introduction

In concluding the dissertation, each secondary objective will be evaluated and addressed. From this, a recommendation will be made in respect of the primary objective of the dissertation regarding *the potential of the proposed RTP tariff as a Demand Side Management (DSM) option for Eskom.*

5.2 Cost implications to Eskom – Secondary objective 1

The first secondary objective was *to define the cost implications to Eskom, brought about by RTP initiated DSM.* To do this, the *net saving on daily running cost* would be calculated, as well as the *net saving in terms of deferring the cost of building the next power station.* Two schools of thought were applied in chapter 3 in an attempt to answer this objective.

5.2.1 Net saving on daily running cost

In chapter 2 of the dissertation, the daily running cost was identified as short run marginal cost (SRMC). The first school applied estimated hourly SRMCs as derived by Eskom's integrated electricity planning department. This method suggested SRMC savings over the next 20 years of R9 392 578.99, in 2000 rand value. On the other hand, the second school used actual scheduling data as well as actual generating cost per power station, but had to be restricted to 21 days' data. Results had to be extrapolated again to cover a year's savings. Savings suggested by this school are derived through permanently offsetting a 640 MW generator at Kendal power station. Savings being suggested amount to R86 154 841.21 in 2000 terms.

Though none of the two schools can be labeled as the most accurate method, the message from both is clear: load shifting under dynamic RTP conditions will result in substantial SRMC/daily running cost savings.

5.2.2 Net saving in deferring the next power station

Savings in deferring capital cost were classified as long run marginal cost (LRMC) and this was proven to become relevant only by the year 2004. Again, results from the two schools differ and values were calculated to be R25 789 540.00 and R69 933 966.00 respectively in 2004 terms. Again, both the methods can be criticised as being inaccurate, but the principal message is the same; that RTP load shifting will also result in substantial LRMC/capital deferment cost savings.

5.3 Minimum amount of load to be shifted – Secondary objective 2

The greatest difference between the two schools is, without doubt the minimum load to be shifted that is a requirement of the second school, whilst the first school is silent about the amount of load to be shifted to effect the mentioned savings. Chapter 2 supports the introduction of such a minimum value in figure 2.1, as it illustrates the non-linear cost curves for generators. The 474 MW, indicated by the second school to be the minimum amount of DSM, is not necessarily the only or the 100% correct minimum requirement. This requirement will be determined on a daily basis by the least committed or smallest unit in service. To be sure that at least one unit will be offset at any time, the minimum load shift required, however, should be reckoned to be the smallest base load unit that has been committed already. Given Eskom's mix of base load plant and the size of Eskom's smaller units in service, the suggested 640 MW is believed to be the maximum requirement.

5.4 Additional load shift potential of South African industries – Secondary objective 3

The survey done and summarised in Table 4.1 of chapter 4 indicated that enough DSM potential is available in SA. The study only included two of the major sectors/processes in SA and made very conservative assumptions. People tend rather to be conservative during surveys than overstate their potential. It is thus believed that most customers will find more load to be shifted once they start exploring and gaining experience with this new concept of dynamic pricing.

Very important is not to forget that with RTP the decision to exercise DSM lies in the hands of the customer. Eskom can only strengthen the signal for DSM in an attempt to improve the probability of DSM reaction to the price signal. This was allowed for by decreasing the DSM potential concluded from the survey by 50% (Table 4.1, last column). Still the required 640 MW was met and it is believed that enough DSM potential does exist in South African industry to satisfy secondary objective 2.

5.5 Final recommendation – Primary objective

It is believed that, given the results of Chapters 3 and 4 and the supporting arguments of Chapter 2, Eskom may, with peace of mind, introduce RTP as a DSM initiative. Though LRMC savings only become a reality in 2004, as Eskom runs out of capacity, the benefits being brought about by RTP are substantial even from year one.

Attention is drawn to the fact that a total new mindset regarding energy control needs to be established in industry. Energy consumption now needs to be managed according to price, versus traditional demand management per integration period. That in itself will take four to five years and figure 3.5 showed Eskom may run out of surplus capacity during that time. One thus needs to introduce RTP as soon as possible, to ensure that the needed reaction, experience and statistical information is available once LRMC comes into play.

It should also be noted that none of the savings calculated in this dissertation will materialise if a system is not developed to record customers' reaction to prices and feed that back to the system operator. Without this feedback loop or "demand side bidding process", no rescheduling of generators will take place and RTP will have no effect on running cost or capital deferment, regardless of customers' reaction to the prices.

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Appendix

Example of Survey Questionnaire used

(3 pages)

REAL TIME PRICING QUESTIONNAIRE

(POTENTIAL FOR ADDITIONAL LOAD SHIFTING UNDER RTP)

1. Background information

Name of customer

Postal Address

Account No

Customer Contact Person

Name

Designation

Tel (w) (   )

Fax (   )

Is the customer willing to participate in RTP ?

Yes	No

Type of industry

Deep Level mining	Smelter

Supply

Directly from Eskom	Indirect - Through Redistributor

Current Tariff

Night Save	Standard Rate	Megaflex	Special Tariff	Other

Specify 'Other' or 'Special Tariff'

Is electricity consumption directly related to production output?

What is the relationship?

2. Eskom information

Customer Executive

Tel (w) (   )

Fax (   )

E - Mail

Person completing this questionnaire

Date   /   /

3. Consumption Profile / Load Shifting Potential

Installed capacity (Eskom)	kVA		
Average Non-simultaneous Maximum Demand		kW	kVA
Average Simultaneous Maximum Demand		kW/kVA	
Do you aggressively control your Maximum Demand?	Yes	No	
If 'Yes', in which way	Computerised	Partly computerised	Manual
and from where	Central Control Centre	Dispatched Control centres	locally at load
Average Base Load		kW/kVA	
Average Controllable load		kW/kVA	
Normal time of Peak Demand	(day)	h (hour)	

Duration and amount of Control: (Assume that the hours following the period load needs to be shifted out off, is all off-peak hours with a cost of less than 5c/kWh.)

For the period 06h00 - 10h00

Base Load		Base Load
Controllable load, if needs to be shifted for 1 hour		
2 hours		
3 hours		
4 hours		
6 hours		
12 hours		

For the period 11h00 - 16h00

Base Load		Base Load
Controllable load, if needs to be shifted for 1 hour		
2 hours		
3 hours		
4 hours		
6 hours		
12 hours		

For the period 17h00 - 21h00

Base Load		Base Load
Controllable load, if needs to be shifted for 1 hour		
2 hours		
3 hours		
4 hours		
6 hours		
12 hours		

For the period 22h00 - 05h00

Base Load		Base Load	
Controllable load, if needs to be shifted for 1 hour			
2 hours			
3 hours			
4 hours			
6 hours			
12 hours			

Given the above; will it be possible to increase the amount of load that can be shifted, by making alterations to the controller or to the plant itself?

Yes	No

If 'Yes', more or less what do you believe will be the cost ?

R10 000	R100 000	R500 000	R 1 'm	R 2 'm	R 5 'm	R 50 'm	More than R 50 'm

Indication of upgrades to be done

Please re-do the section "*Duration and amount of Control*", using the dotted blocks, and assuming that the above mentioned upgrades have been done. (Estimates)