# Review of Security of Supply in South Africa

## A Report to The Department of Public Enterprise

by

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Support to the Restructuring of Public Enterprises in South Africa (SRPESA) – A DFID-funded Programme

## NOTE: This Report is Confidential to the Department of Public Enterprise

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# 1 Executive Summary

In South Africa, security of electricity supply is one of the most important issues facing the electricity industry currently, its customers and Government. Key aspects of electricity supply security are the availability of adequate generation capacity to meet customer demand at any time and a secure and reliable transmission system to deliver power to all regions of the country. Maintaining a secure electricity supply is essential for any developed economy. However, determining the appropriate level of supply security is a trade-off between the costs involved in improving power system reliability and the losses to the economy and customer welfare associated with power outages. This study makes recommendations and provides guidance as to how that trade-off can best be achieved.

Following the difficulties at Koeberg nuclear power station, the electricity supply and demand balance is extremely tight, particularly over the current winter peak demand season. Even with a resolution of the Koeberg problems, the national supply/demand balance is likely to remain tenuous during the next few years. Given Eskom's key role in planning and managing supply security, it is therefore appropriate for the Department of Public Enterprise (DPE) to develop a position on security of supply, for both the immediate short-term following the Koeberg incidents and the medium to longer-term. In developing this DPE position, it is proposed to engage with Eskom, DME, NERSA and other relevant parties that have a responsibility for electricity supply security and energy policy.

*Internationally*, the importance attached to power system security has increased significantly in recent years, following large-scale power outages in North America and Europe. ***In many countries, the traditional approach of leaving security to be managed by a utility has been replaced by a transparent and inclusive process, with Governments and Regulators taking a pro-active position***. In those markets where competition does not exist or is not extensive, an explicit generation security standard is usually set, as a basis for future planning. In those markets where there is extensive competition in generation and retail, Governments and Regulators are clearly concerned about the ability of the market to deliver adequate security of supply and are putting in place measures to ensure adequate security. International experience also shows that ***maintenance and asset management are crucial to avoid increases in the number of concurrent fault events that would risk more and larger interruptions to customers' supplies***.

The security of an electricity system is affected by all elements of the supply chain – generation, transmission and distribution. The main focus of this study is on generation and transmission.

The adequacy of generation capability depends upon such factors as the installed capacity, unit size, plant reliability, demand forecasting error and the shape of the load curve. The ***Reserve Margin is a deterministic criterion,*** which provides perhaps the simplest available measure of system security. However, it does not take explicit account of the fact that security is dependant upon underlying factors such as the size of individual generating units and the relative reliability of generating units on a system.

Eskom has recently stated that a reserve margin of 15% to 25% is the desirable range required to meet Eskom's obligation to supply (OTS), although this OTS is not defined explicitly. However, this level of plant margin is somewhat higher than has been considered appropriate by Eskom in the past and it is unclear what has driven this change in policy.

As the reserve margin on a system is increased, the probability of failing to meet demand as a result of inadequate generation will fall. Due to the probabilistic nature of security of supply, it is only possible to provide an expectation of failing to meet demand. As load grows, the reserve margin is eroded, until such time as new plant is commissioned. The decision as to when new plant should be commissioned depends upon what reliability of supply is deemed to be appropriate. Increased reliability implies greater investment costs while reduced reliability results in an increased expectation of power shortages, which have an implied cost to customers. Appropriate reliability criteria are derived by balancing these two factors.

The construction time of new power plant has a dramatic impact upon the level of uncertainty involved in generation planning. The longer the construction period, the greater the uncertainty, due to such factors as demand forecasting error, performance of existing generating units and uncertainty over the commissioning dates of new generation units. For example, the decision as to whether to build a combined cycle gas turbine (CCGT) plant, with a relatively short construction time, or a coal fired plant, will have a significant impact upon the required plant margin in South Africa.

A key criteria used by Eskom for determining the need for additional generation capacity is the "Cost of Unserved Energy" (CoUE), which is assumed to represent the value to customers of system security. This approach, although widely used in the past in certain countries such as the USA, is now recognised as not being an adequate basis for determining power system security, as has been illustrated by the response of customers to the recent power outages in the Western Cape.

The overall responsibility for supply security in South Africa lies with the Department of Minerals and Energy (DME) but in the short-term (to 2008) Eskom has an obligation to meet the need for additional capacity. ***However, there is no agreed basis or standard for the level of supply security to be provided***. ***It is recommended that an unequivocal security standard should be established.***

Eskom is currently responding to a critical shortfall in generation capacity, partly due to the Koeberg problems but also to the fact that over the past few years ***the reserve margin has fallen to record low levels compared with the historic situation***.

***There is now an urgent need, first to determine a suitable security standard, in order to define what level of reserve margin should be maintained and second, to clarify the responsibility for meeting that security standard, given the Government policy that new generation capacity shall be provided 70% by Eskom and 30% by the private sector.***

The supply problems during 2006 have highlighted, not only concerns about generation capacity in South Africa but also concerns about the adequacy of the transmission system to deliver power to all of South Africa's regions. It has become apparent that, although the transmission system is generally designed to be resilient to a single circuit outage, the transmission system does not meet this criterion in all regions. This is as a result of the economic criteria used by Eskom in order to justify transmission system augmentation, which are based, in part, upon the Cost of Unserved Energy (CoUE). The result of this approach is that in some regions of South Africa where demand exceeds the local generation capacity, the security of supply is lower, due to the limitations of the transmission system, than in those regions where the generation exceeds the demand. ***Effectively, customers in some parts of South Africa have a sub-standard supply security, as a consequence of a perceived value of supply interruptions, i.e. the CoUE, which has not been subject to rigorous validation***.

A key element of system planning, both in the short-term and longer-term, is developing a reasonably accurate forecast of the demand. This study has revealed a number of areas where the current approach to demand forecasting could be improved, at relatively low cost. However, the main finding of the study, with regard to demand forecasting, is the need for a truly integrated approach. At present, a theoretically integrated approach exists within the National Integrated Resource Plan (NIRP), under the jurisdiction of NERSA. However, in practice it is apparent that the NIRP is largely irrelevant to Eskom's planning, which is based on its own Integrated Strategic Electricity Plan (ISEP). It is appropriate that planning should be under the control of an independent body and there are aspects of the new approach, adopted within NIRP3, that are advantageous. However, the current NIRP approach fails to take sufficient account of the considerable expertise on demand forecasting that has been developed within Eskom. In addition, municipalities, as retailers to around one-half of the customer load in South Africa, need to be more fully involved. ***There is strong case for the two separate planning processes, ISEP and NIRP, to be brought together in a fully transparent process, open to all parties and managed on a consistent and regular basis***.

A major input to the demand forecast is the assumed level of economic growth in South Africa. It has been argued by Eskom that Government targets for growth may be optimistic but recent figures suggest that GDP growth is currently strong and there are grounds for remaining optimistic about the future. ***Currently, however, there is lack of agreement, within the electricity industry, about the assumed level of economic growth that the industry is preparing to meet. This is not a good basis for planning***.

The problems experienced with the availability of the Koeberg power plant have demonstrated very clearly that, with the generation and transmission infrastructure that is currently available in South Africa, the loss of a single 900MW generating unit at the Koeberg station for any extended period during the winter months results in Eskom being unable to meet customer demand in the Western Cape. This illustrates clearly that ***the security of electricity supply in South Africa is currently at risk from a single (albeit low probability) event***.

Over the past 10 years the reserve margin has fallen very significantly as a result of growth in electricity demand of around 3% per annum (which equates to approximately 1,000MW of additional peak demand each year) and the very limited amount of new generating plant that has been commissioned. However, ***the monitoring of reserve margin is inadequate and inconsistent.*** There is no agreement between NERSA and Eskom on whether to include demand-side management (DSM) measures as part of demand or as a supply-side option and there is lack of clarity concerning the distinction between the reserve margin adopted for long-term planning purposes and that used for short-term operational purposes. ***It is recommended that these anomalies should be removed and that a consistent, transparent and regular monitoring system be established to track the reserve margin and the availability of generating plant and the transmission system.***

***Eskom's plans for generation capacity expansion (ISEP) concentrate on the long-term supply position and do not focus on alleviating the shortfall in supply security in the short term***. If the return to service of mothballed plant, the commissioning of any of the new gas turbines run behind schedule or the forecast level of Demand-Side Management (DSM) fails to materialise, the capacity situation in the short term will become tighter. Contingency measures for dealing with such possibilities should be in place.

***Steps could be taken now to improve the short-term position***. For example, additional open-cycle gas turbine (OCGT) plant could be procured, possibly as extensions to the existing tenders by Eskom and DME. The advantages of OCGT plant are flexibility (including the possibility of later conversion to run in a combined cycle mode), ability to locate in regions where generation is in deficit (thus adding to security in those regions) and the relatively short timescale for construction. The high cost of fuel is a factor to be considered but not to cause rejection without taking account of other factors.

Although imports and exports are relatively small, compared with the total electricity demand in South Africa, the levels of imports and exports are significant in comparison with the reserve margin. ***Thus, there is a need for a stronger focus on imports and exports***, particularly with regard to the contractual commitments associated with both. It is also recommended that the risks to supply security, associated with imports, be monitored on a probabilistic basis.

***In all of the other markets reviewed as part of this study, there is significant information in the public domain concerning security of supply and reserve margin.*** By contrast, in South Africa, almost all of Eskom's documents on security of supply and reserve margin are either unpublished or specifically deemed to be confidential. Whilst Eskom may argue that their ISEP results are confidential, the argument is invalid, particularly for a dominant state-owned entity not in competition with other utilities. International experience shows that in both competitive and monopolistic markets, the type of information produced in Eskom's ISEP is deemed to be public domain information, in order to ensure that all interested parties are aware of the plans, issues and options under consideration. It is also likely that a more open process may have revealed the serious disjoint that exists, between the long-term planning process and the process of delivering the required capacity additions. ***The lessons are that, where key decisions are being made, it is vital that the plans and the associated assumptions have the widest possible exposure to enable alternative ideas and options to be considered. Eskom does not have a monopoly on good ideas.***

It is therefore strongly recommended that Eskom's ISEP results, together with the associated procedures and policies, should be published in full. However, it is recognised that there may be circumstances where certain information may need to be kept anonymous for reasons of commercial confidentiality.

In addition to making the ISEP process fully available to the public, it is recommended that a more consistent approach be taken towards the updating of the ISEP demand forecasts and expansion plan options. It is recommended that a demand forecast should be updated at least annually; possibly at some point soon after the actual winter peak demand has been established.

***It is recommended that the DPE should initiate discussions with NERSA, Eskom and all interested parties with a view to integrating the ISEP and NIRP processes into one seamless national process***. It is recommended that the single integrated planning process be managed and co-ordinated by NERSA, with Eskom being responsible for agreed components of the plan. The outputs from this plan should be made public at least on an annual basis and more frequently if specific circumstances require it. In particular, in a period where the supply situation is tight, it is vital that a current plan is available for immediate implementation and that such information is in the public domain on a timely basis.

# 2 Introduction

This report provides the results of a specific study, undertaken at the request of the Director General of the Department of Public Enterprise (DPE) into the security of electricity supply in South Africa. The study is a component of the programme of Support to the Restructuring of Public Enterprises in South Africa (SRPESA), funded by the UK Government's Department for International Development (DFID) and implemented by Adam Smith International (ASI).

Following numerous supply interruptions over recent months, some of which have had a widespread impact, considerable importance is attached to issues of electricity supply security. Concerns about supply security include: the reliability of distribution networks and the lack of adequate investment and maintenance of these systems; possible skill shortages within electricity utilities that may threaten the utilities' ability to maintain a secure supply system; the security standards to which the transmission system has been designed; and the amount of generating capacity available to provide power for customers' use.

Generating capacity and, more specifically, the margin between the total installed capacity and the maximum demand on the system, has been a major topic of concern, particularly to DPE. However, it is important to note that, whilst the study includes consideration of the generating reserve margin, this is only one of a number of aspects of supply security that are addressed in this study.

This report includes a discussion of many aspects that affect the security of electricity supplies in South Africa but focuses mainly on aspects of generation and transmission. That is not to say that distribution is less important, since distribution networks are generally the cause of considerably more customer interruptions than generation shortages or transmission problems. However, given the relatively short time in which to conduct this study, it has been largely confined to generation and transmission issues.

A general discussion of security and reliability issues is provided in Section 4 of this Report, followed by examples from other countries to illustrate the international perspective (Section 5) and a detailed discussion of the security of supply situation in South Africa (Section 6). In addition to providing an analysis of the current position with regard to security of electricity supply in South Africa, this report includes a number of recommendations for change, which is believed would improve security of supply. These recommendations include: setting an explicit security standard (which does not exist at present in South Africa), guidance on how that standard should be set and implemented; significantly increased transparency in the area of generation and transmission planning and demand forecasting; putting in place a systematic monitoring of the security of supply position; integration of the processes of the National Integrated Resource Plan (NIRP) and Eskom's Integrated Strategic Electricity Plan (ISEP); an increased focus on imports and exports; some ideas for alleviating the security position in the short-term; and a number of detailed recommendations concerning the demand forecasting and system planning approaches. The conclusions of the Study are summarised in Section 7 of this Report and Section 8 contains a summary of the recommendations.

# 3 Background to the Study

The following Terms of Reference (TOR) for this study are contained within ASI's Project Proposal[1] to the Director General of 10 March 2006.

*"In addition to specialist support in the above work areas, the DPE wishes to carry out a specific study on the issue of national electricity supply security, which has been highlighted by the recent incidents at Koeberg nuclear power station, resulting in one of the two generating units being rendered inoperative and numerous supply interruptions. The Koeberg situation has highlighted the threat to security of supply both nationally and regionally. It demonstrates the need for a clear policy to be established by the DPE with regard to the level of supply security that Eskom should provide; the associated levels of reserve capacity margin and transmission capability that are required; and the implications for policy governing energy imports and exports.*

*As a result of the difficulties at Koeberg nuclear power station, the electricity supply and demand balance is already extremely tight and demand is expected to increase as we move towards the winter peak demand season. Even with a resolution of the Koeberg problems, the national supply/demand balance is likely to remain tenuous during the next few years, until the full capacity of the return to service plant (Camden, Grootvlei and Komati) is available and the new open cycle gas turbine plant is commissioned.*

*It is therefore appropriate to develop a DPE position on security of supply, both in the immediate short-term following the Koeberg incidents and in the medium to longer-term. In developing a DPE position, it is proposed to engage with Eskom, DME, NERSA and other relevant parties that have a responsibility with regard to electricity supply security and energy policy."*

This study includes:

- A description of security of supply and reliability issues for electricity systems generally, including how an appropriate reserve margin is determined and how the responsibility for supply security is dealt with in electricity markets.
- A review of security of supply in a selected number of other electricity markets, comparable to that of South Africa, in order to demonstrate the range of Governmental, regulatory and industry bodies that are involved in the security issue in these markets.
- A review of the existing security of supply position in South Africa, including; the responsibilities for supply security; the basis on which a security of supply standard is incorporated in the generation and transmission planning process and the extent to which the level of reserve margin is adequate to meet the required level of supply security in South Africa.
- Conclusions and Recommendations on; measures that could be taken to improve the security of supply in the short, medium and longer term; improving

[1] The ASI Project Proposal covers general assistance to DPE over the period April 2006 to May 2007 and a specific study for DPE on security of supply/reserve margin.

the process of determining the reserve margin, monitoring the demand/supply balance and making information available to interested parties.

In this study, the principal basis for the analysis of South Africa's supply security position is Eskom's most recent Integrated Strategic Electricity Plan (ISEP) - ISEP10, together with additional information obtained from Eskom during the course of this study. The timing of this study is aimed at providing DPE with recommendations by the end of July 2006, shortly after the time of the expected peak demand and when the demand/supply balance is likely to be at the most critical position. It was hoped that, by this time, the NIRP3 report on the reserve plant margin would be available, to provide a further, independent, input to this study. However, delays to the NIPR3 process have put back the timetable for delivery of the reserve margin report within NIRP3. Consequently, although a detailed review of the NIRP3 demand forecasts is included in this study, it has not been possible to review the NIRP3 reserve margin analysis. Thus, the analysis for this study concentrates largely on a review of Eskom's ISEP10.

As in all electricity markets, it is not just the level of reserve margin that is important to supply security. More important is the process by which that level of reserve margin is determined. During the last few years, Government policy in South Africa has changed significantly. Prior to the White Paper of 1998[2], Eskom had a near monopoly on electricity generation, with the exception of the relatively small amount of generation capacity owned by Municipalities and private generators. Implementing the White Paper, a policy was initiated to open up the electricity generation market to competition, by preventing Eskom from building new capacity and at the same time pursuing a part privatisation of existing Eskom generation assets.

In 2004, Government policy was changed again to the present policy of Eskom retaining all existing generation assets and allowing Eskom to build up to 70% of all new generation capacity in South Africa. These changes in Government policy and their impact upon decisions to build new power plant are likely to have had a significant impact upon supply security in the short to medium term. Other policy issues, including fuel diversity and promotion of renewable energy, may also impact on supply security but the policy on new generation build is likely to be most significant.

Electricity markets in many countries have moved from traditional monopolistic markets, (with retail markets tied to generation companies through vertical integration of generation, transmission, distribution and supply), to competitive or partly competitive markets, where generating companies compete with each other for a share of the wholesale or retail market. An alternative approach, pursued particularly in developing countries, is to allow the existing vertically integrated utility to retain the retail monopoly and introduce private power production by competitive tender to sell power to the vertically integrated monopoly utility. Thus, although there is no competition within the power market, there is competition (by open tender) to produce power for the monopoly utility. South Africa is currently pursuing a variant of this model, where Independent Power Producers (IPPs) are currently being invited to tender for around 1000 MW of peaking plant, as part of the overall Government policy to limit Eskom's new build to 70% of new generation capacity. To what extent this policy will be successful in attracting IPPs remains to be seen. What is also unclear, however, is the extent to which

[2] White Paper on the Energy Policy of the Republic of South Africa, Department of Minerals and Energy, December 1998.

this policy will ensure the required level of supply security and how the responsibilities for delivering that level of supply security are to be allocated. In particular, there is a requirement to facilitate the building of a significant amount of new generation capacity.

# 4 Delivering Security of Supply

## 4.1 Background

Maintaining a secure electricity supply is essential for any developed economy. Within this context, a power utility is responsible for making a supply of electricity available at an acceptable level of reliability. The level of reliability that is appropriate is a balance between the cost associated with improving reliability and the additional cost to the economy implied in poor reliability.

In most developed countries, the contribution of shortfalls of generating capacity to the outages experienced by the majority of customers is small compared with interruptions arising from problems in transmission and distribution networks. The large-scale power failure in North America during August 2003 was the result of transmission failures and the failure of system management rather than as a consequence of a generation shortfall. The power failures in Italy and Scandinavia in the autumn of 2003 were also a direct consequence of transmission failures. The requirement to transmit increasing quantities of power over greater distances as a result of local shortfalls in generation capability places transmission systems under increased pressure.

The recent supply interruptions to customers in the Western Cape were as a consequence of a combination of an extended unplanned outage of one unit at Koeberg nuclear power plant and failures of the transmission circuits that supply the Cape region.

Although in most developed countries generation shortfall is, in itself, rarely a cause of customer interruption, in view of the potential consequences of large-scale outages, most utilities lay down strict generation security criteria.

Currently, Eskom operates most of the generation and transmission facilities in South Africa and has a de facto obligation to maintain security of supply at the wholesale level (i.e. generation and transmission). Distribution is undertaken by both the Municipalities and by Eskom.

## 4.2 Power System Reliability

The adequacy of a power system relates to the existence of a system capable of satisfying customers' demand throughout the year. A power system comprises facilities necessary to generate energy, together with the associated transmission and distribution systems to transport the energy to the customer. The generation, transmission and distribution systems all impact upon the supply quality to the customer and outages on any of these components can result in interruptions to customer supply. Failures of generation or transmission are important because such failures can affect large sections of the system and therefore can have widespread consequences. Failures in distribution systems, although much more frequent (particularly for rural customers), have much more localised effects. Typically, an average customer might expect an average of around one hour[3] per year of lost supply through distribution difficulties, whereas customer interruption due to generation shortfall occurs only rarely.

Generally, indices of power system reliability include exogenous events due to weather but exceptional weather-linked outages may be subject to separate reporting. Generation shortages or system difficulties may also be experienced as a result of strike action by staff in a utility or in a related fuel industry, which can sometimes have a more significant impact on customers than the inherent reliability of the power system.

## *4.3 Reliability of the Generation System*

In planning future generation requirements, it is necessary to determine what system capacity is required to meet future demand economically and at an acceptable level of reliability. Generation adequacy is usually assessed by determining the likelihood of there being sufficient generation to meet customer demand, or in other words, by calculating the risk of supply shortages occurring. The risk of supply shortages can be calculated by using statistical techniques to determine the probability that demand will exceed supply.

The installed capacity on a power system must exceed the expected demand to allow for such factors as generator breakdown, severe weather, demand forecast uncertainty and transmission problems that could result in a loss of generation. This additional capacity is known as reserve capacity. The ratio of reserve capacity to load is known as the reserve margin. The reserve margin is usually expressed as a percentage of the annual peak demand.

*Reserve margin = (installed capacity – maximum demand)/maximum demand x 100%*

In general, too small a reserve margin of generating capacity with respect to demand would result in excessive levels of supply interruption, while too large a margin would result in unnecessary investment expenditure. Reliability criteria that are utilised for measuring the adequacy of generation capacity are defined in Appendix A.

Eskom has recently stated that a reserve margin of 15% to 25% is the desirable range to meet Eskom’s obligation to supply (OTS), although this OTS is not defined explicitly. However, this range of plant margin is somewhat higher than has been considered appropriate by Eskom in the past and it is unclear what has driven this change in policy.

In planning South Africa’s future generation requirements, there is a need to determine what system capacity is required to meet the future demand economically and at an acceptable level of reliability. However, at present, there is no explicitly defined generation security standard in South Africa.

The adequacy of generation capability depends upon such factors as the installed capacity, unit size, plant reliability, demand forecasting error and the shape of the load curve. A reserve margin is a deterministic criterion and provides perhaps the simplest available measure of system security. However, it does not take account of generator unit size or the relative reliability of generating units on a system.

[3] Customer interruptions, both in terms of frequency and duration, are significantly higher in rural areas supplied via overhead networks, than in urban areas using underground networks.

As the reserve margin on a system is increased, the probability of failing to meet demand as a result of inadequate generation will fall. Due to the probabilistic nature of security of supply, it is only possible to provide an expectation of failing to meet demand. As demand grows, the reserve margin is eroded, until such time as new plant is commissioned. The decision as to when new plant should be commissioned depends upon what reliability of supply is deemed to be appropriate. Increased reliability implies greater investment costs while reduced reliability results in an increased expectation of power shortages, which have an implied cost to customers. Appropriate reliability criteria are derived by balancing these two factors.

The construction time of new power plant has a dramatic impact upon the level of uncertainty involved in generation planning. The longer the construction period, the greater the uncertainty, due to such factors as demand forecasting error, performance of existing generating units, and uncertainty over the commissioning dates of new units. For example, the decision as to whether to proceed with a Combined Cycle Gas Turbine (CCGT) plant, with a relatively short construction time, or a coal fired plant, will have a significant impact upon the required plant margin in South Africa.

Factors that influence the size of the plant margin required to deliver a given level of reliability include:

- The time needed to construct new generation capacity;
- The forced outage rate (a measure of plant reliability) of generating units on the system;
- The number of days of planned outages (i.e. outages for maintenance purposes) required for generating units;
- The ratio of the largest generating unit relative to the system capacity;
- The load profile (the shape of demand, daily and annually);
- Constraints within the national transmission system, which may limit the amount of power that can be transported from a region with surplus generation to another region with a generation deficit; and
- The interconnections available to neighbouring utilities.

A plant margin that is used for long term planning purposes differs from an operational planning margin that is used in operational timescales. In the operational timeframe, it is necessary to ensure that sufficient generating capability is available in order to cater for most credible contingencies such as the sudden loss of a large generating unit. In the planning timeframe there are additional uncertainties due to factors such as when new generating plant will be commissioned and how fast the system demand will grow. Thus, the reserve margin for planning purposes necessarily exceeds the operational planning margin.

Eskom retains an operational reserve of 2,500MW[4], which equates to an operating margin of approximately 6% of the current installed generating capacity. Some of the existing operational reserve is provided by large customers who have signed

[4] 500 MW Regulating reserve (for AGC); 500 MW Instantaneous reserve (for governing); 800 MW 10-minute reserve (approximately 400 MW generation above MCR; and 342 MW from gas turbines). Reserves are also obtained from the demand side.

interruptible load (IL) contracts. In general, Eskom includes the available interruptible load contracts in its calculation of the available reserve margin[5].

There are two basic options that are used to derive a suitable plant margin - the deterministic and probabilistic approaches. A deterministic approach indicates the total generation that is expected to be needed at peak demand hours whereas a probabilistic approach takes into account the random nature of the different elements of the power supply/demand balance (system load, unit availability, etc) and calculates the probability that the system is not be able to supply all the demand.

**The probabilistic approach** often involves the calculation of the Loss of Load Probability (LOLP) or the Loss of Load Expectation (LOLE). Such analysis is based on values for planned and unplanned outage rates for individual system components in conjunction with a demand forecast. A Monte Carlo based computation technique is usually employed to derive the results. However, whilst probabilistic approaches are used to determine the LOLP or LOLE, it is usual to express the outcome in terms of the Reserve Margin, since this term is more easily understood.

**A deterministic criterion** is usually based upon an examination of a number of constraining situations (such as the single most serious event) with the assumption that if system operation can be assured for these cases it will be secure for all situations. While a deterministic approach is easier to understand, it does not reflect the reality that a given level of security of supply is in fact contingent upon ensuring that the underlying factors influencing the ability to meet demand are treated in an appropriate statistical manner. Reliability indices derived through probabilistic methods therefore constitute a better estimation of the risk of failure than deterministic indices.

Both methods employ information on past performance of the power system and expected performance in the future. The deterministic approach is less mathematically rigorous than the probabilistic approach but is more readily understandable.

The absolute level of system reliability is difficult to calculate with precision due in part to uncertainty of the data used in its calculation. Reliability criteria do, however, allow for an objective comparison of the relative system security associated with different planning options.

## *4.4 Reliability of Transmission Networks*

The reliability of a transmission network can never be 100% and is affected by factors such as:

- The design criteria adopted at the planning stage (e.g. N-1[6]).

[5] This appears to be under review, according to an Eskom document on Reserve Margin.

[6] The N-1 criterion is widely used and basically sets the requirement that a single incident should not jeopardize the secure operation of the interconnected network. Such incidents are, for example, the tripping of a generating unit, a transmission or distribution line or a transformer. This principle is used worldwide, though its practical details may vary widely, depending on local circumstances and reliability requirements. On the highest voltage levels, it implies that the grid must be meshed and the necessary spare capacity in generation and transmission be foreseen. A more onerous criterion is N-2 which requires the system to withstand the simultaneous loss of two network elements.

- The level of investment in reinforcing the system.
- The level of refurbishment of the existing transmission equipment.
- The effectiveness of the maintenance regime.
- The effectiveness of the monitoring and control systems.

In delivering an overall level of security to customers in is necessary to achieve an appropriate balance between expenditure on generation, transmission and distribution facilities. Typically for any given power system, there are defined levels of security associated with different magnitudes of demand to be supplied. The larger the load supplied the greater the level of security that is required to meet planning standards. Given the widely varying costs that can be involved in securing a given size of load, it may be appropriate in certain specific circumstances to relax the level of security if the associated costs are considered excessive. However, the international practice in such circumstances is to have a specific derogation from the security standard[7].

In reporting the operation of its transmission network Eskom uses two key measures of transmission reliability:

- System minutes lost[8] associated with transmission outages; and
- The number of customer interruptions.

[7] The South African Grid Code requires an economic case to be made for reinforcement of transmission to improve security.
[8] A system minute of unsupplied energy is equivalent to the amount of energy that would not have been supplied if the system were totally interrupted for 1 minute at the time of annual peak demand.

# 5 Security of Supply in Other Countries

For the purposes of determining appropriate security of supply standards for South Africa, it is instructive to review the approach adopted in a select number of other countries. Eskom has already commissioned some benchmarking analysis in this regard from DataMonitor, which Eskom has made available for this study. Independently, however, the authors of this study have prepared a review of the approach to security of supply in four particular markets:

- The National Electricity Market of Australia;
- Britain (the integrated electricity market of England, Wales and Scotland);
- France; and
- Texas, USA

The above four examples were chosen in order to reflect a wide range of market structures but each example has particular relevance to South Africa. Since South Africa's electricity industry has a strongly developed infrastructure, established over many years, it is not appropriate to compare the electricity systems of South Africa with those in developing countries. Thus, the comparators are chosen to reflect examples of best international practice, under a range of market types. Australia's National Electricity Market (NEM) is similar in size to the South African electricity market and, like South Africa, has mainly coal-fired generation plant and has no interconnection with other countries. Britain has changed from largely coal-based generation to a mix of gas, coal and nuclear with a growing renewable content. France is similar to South Africa in that its electricity market is dominated by a large vertically integrated state-owned utility, Electricité de France. Texas is unique among the North American markets in that it has almost no interconnection with other parts of USA or Canada.

Before examining the detailed approach to security of supply in these four markets, it is useful to explain the generic approach that has been adopted in North America and Continental Europe, both of which suffered severe supply interruptions during 2003 and, as a result, have had to review their security of supply measures.

## *5.1 Continental Europe*

The Union for the Co-ordination of Transmission of Electricity (UCTE) is responsible for co-ordinating the interests of transmission system operators (TSOs) in 23 European countries covering the bulk of continental Europe, excluding Scandinavia, Russia and certain other eastern European countries[9]. Their common objective is to maintain the security of operation of the interconnected power system of the member countries.

For most power systems, the main risk is not having sufficient generation capacity to meet demand at time of system peak and a power balance established at time of peak load is normally sufficient to provide a good estimation of generation adequacy. The basic methodology consists of comparing the installed generating capacity with the

[9] The UCTE region covers Belgium, Germany, France, Slovenia, Croatia, Luxembourg, Netherlands, Austria, Switzerland, Bosnia Herzegovina, Spain, Portugal, Italy, Greece, Serbia and Montenegro, Macedonia, Romania, Bulgaria, the Czech Republic, Poland, Hungary, Slovakia, and Western Ukraine.

forecast demand, taking into account unavailable or unusable generation capacity that results from fuel interruptions, forced outages, overhauls and, in addition, the reserves required in operational time frame.

The UCTE methodology is a deterministic approach focused on the power balance at time of peak load, which allows the assessment of the generation adequacy on the basis of the reserves available at this time. An index has been defined which corresponds to the level of reserves consistent with a 1% risk of not being able to meet the system load while maintaining sufficient reserves for frequency control.

Due to significant differences among the various power systems in Continental Europe (their size, the generation mix, the nature of the system load, the level of interconnection and the level of risk that is considered acceptable) it is very difficult therefore to define a common reserve margin to ensure that demand is met with an acceptable level of security.

Another important consideration is that liberalisation and competitive generation markets, in a number of instances, have led to reducing the plant margin considered necessary to meet load for a given quality of supply and security standards. Plant margins that appeared satisfactory under centrally planned regimes have been considered by the markets as too high under liberalised market structures.

## *5.2 France*

### 5.2.1 Background to the Electricity Sector in France

The electricity sector in France is similar to that of South Africa in one particular aspect, namely, the existence of a large dominant state-owned entity and, for this reason, the French electricity sector is of significant relevance to this study. Electricité de France (EdF) dominates both the generation and the retail sector in France, where it generates over 90% of the total power generated and still retains over 95% of the retail customer load[10]. In 2004, EdF became a limited company but the Government of France remains the majority shareholder.

The French power system has over 100 GW of installed generation capacity, which produces around 550 TWh per year. Almost 80% of the electricity generated in France is derived from EdF's nuclear power plants. France is a net exporter of power, with around 12% of the power generated being sold to utilities in neighbouring countries via interconnections with other members of the Union for the Co-ordination of Transmission of Electricity (UCTE) synchronously interconnected system and to Britain via a Direct Current (DC) undersea cable link. However, the export position is due to change over the future as domestic demand grows.

### 5.2.2 Overview of the French Electricity Market

Unlike Australia and many of the North American wholesale electricity markets, which have integrated system and wholesale market operations, there is a clear separation in France between, on the one hand, the system operation and physical market for near-real time power; and on the other hand, the day-ahead and other futures market for electricity trading. In France the power system transmission operator, Reseau de

[10] Retail competition in France is currently limited to non-residential customers but is due to be available to all customers in 2007.

Transport d'Electricité (RTE), has responsibility for the operation of the French power system, including the balancing of supply with demand and the operation of the balancing mechanism, which was introduced in 2003.

A *balancing mechanism* (or balancing market) refers to a mechanism for balancing of supply and demand that incorporates a near-real time market for offers and bids to increase/reduce generation/demand. In common with a number of other European markets, the balancing mechanism in France is operated by the system operator, while day-ahead and other forms of futures trading are conducted on a *power exchange*, which operates outside the jurisdiction of the system operator and is open to participation by any trader and not restricted to entities actually involved in the production or supply of electricity. The French power exchange is administered by Powernext[11]. In addition to the power exchange, power is traded bilaterally, in over-the-counter (OTC) markets and via an auction of part of EdF's capacity, known as Virtual Power Plants (VPP auction).

### 5.2.3 Security and Reliability in France

The responsibility for security and reliability of electricity supply has a legal basis, under the Law concerning the Modernisation and Development of the Public Electricity Service, February 2000. This law places an obligation on the power system transmission operator (RTE) to "ensure the balance of electricity flows on the network at all times, as well as the security, reliability and efficiency of this network". It is interesting to note that the February 2000 Law places system security at the highest priority of the obligations on the system operator and, by implication, above that of running a competitive and efficient market.

### 5.2.4 Forecasting Demand and the Supply/Demand Balance

As with other balancing markets, RTE provides a range of valuable and public information to market participants and other stakeholders on the situation concerning the electricity supply/demand balance. This information includes:

- Day-ahead forecasts, based on comparisons of historic data for similar day types with weather data.
- Medium-term forecasts (weekly, monthly and annual).
- Long-term forecasts in the form of the Generation Adequacy Report.

The Generation Adequacy Report is published by RTE, as part of its obligations under the February 2000 Law. The current report, published in 2005, covers the period 2006-2016. The report details the results of a study of the amount of new generation capacity that is needed to be added to the system over the 10-year period in order to meet the level of forecast demand, assessed as three demand scenarios, low, medium and high.

The specific criterion for assessing the level of reserve margin required is that the Loss of Load Expectation (LOLE) shall not exceed three hours per year on average,

[11] Powernext operates a market for day-ahead and monthly futures and carbon trading, completely separate from the balancing market operated by RTE. However, unlike the more established Nordpool market in Scandinavia, the volume of electricity traded on Powernext is small compared with the amount actually produced and consumed in France. This is likely to be partly due to the market dominance of EdF.

consistent with one shortfall every ten years. In addition to determining the amount of generation capacity needed nationally, the report specifically details the amount of generation and transmission capacity required to strengthen the security of supply in certain regions of the country.

It is interesting to note that the report states that, although the above LOLE criterion has been in existence for many years, the actual level of system security has generally exceeded this level. As the supply-demand balance is now becoming more critical, consideration is currently being given to a more stringent criterion.

### 5.2.5 Determining the Reserve Margin

A combination of a probabilistic and deterministic approach is adopted. The N-k rule determines the maximum accepted risk level. Where the extent of an outage is deemed to be unacceptable in terms of the consequences (measured as a proportion of the system affected), preventive measures are taken, if necessary, even if they are costly. Otherwise, where the extent of the outage is deemed to be an acceptable risk, the implementation of preventive measures must be the result of technical and economic analysis. Current rules are that the likelihood of calling upon exceptional means and safeguard actions (interruptible contracts, customer load shedding, escalation to maxgen for generating units, etc.) is less than 1% at the morning peak and less than 4% at the evening peak.

In terms of load contingencies, the French system is managed to deal with the impact of variations in temperature on demand. In autumn, winter and spring (France has a winter peaking load), a temperature deviation of 1˚C results in a load variation of up to 1,600 MW.

In terms of operating reserve, the recommended reserve is determined by UCTE for each member system. For France, the UCTE rule recommends a permanent primary reserve of 700 MW; a secondary reserve depending on demand level but with a minimum of 500 MW; a rapid tertiary reserve (15-minute reserve) of at least 1000 MW; and an additional tertiary reserve of at least 500 MW. The objective is to have a real time margin of 2,300 MW within 2 hours and around 1,500 MW within 15 minutes, in order to recover the loss of the largest single generating unit on the system (1300 MW) within 15 minutes.

### 5.2.6 Managing System Security

Various documents, available publicly from RTE, demonstrate the high degree of attention paid to reliability issues and the need to ensure security of supply in France. In addition to the annual reliability audit referred to below, RTE publishes a “Memento of Power System Reliability”, designed specifically to be instrumental in improving power system reliability. This is a highly detailed document describing various scenarios for power outages and how such scenarios are dealt with in order to stabilise the system, limit the severity of incidents in terms of customer interruptions and restore the system to normal in the most efficient and timely manner. The availability of such a document in the public domain is clearly beneficial, not only in demonstrating RTE’s commitment to reliability but also to ensuring a common understanding of the policies and actions necessary to implement the policies, among producers and distributors.

The power system in France is managed centrally by RTE's national dispatch centre (CNES), which is responsible for:

- Generation-load balance;
- Voltage control and power flow on the 400 kV system; and
- Electricity exchanges at the borders with neighbouring countries.

Supporting CNES at the national level are 7 regional control centres (URSE), which are responsible for:

- Monitoring the 400 kV system in support of CNES;
- Voltage control and power flow on the sub-400 kV systems; and
- Remote control of EHV substations.

In addition to managing the power system in France through the balancing mechanism, RTE has agreements with its counterparts in neighbouring countries to provide mutual back-up. For example, the agreement between RTE and National Grid (Britain) requires each entity to maintain 500 MW of real-time reserve capacity available (1000 MW in emergency), to be accessed by the other operator if required. Similar agreements exist with other neighbouring system operators[12].

It is important to note that the interconnection with other systems provides each system with a mutual advantage in terms of the reserve margin necessary to be maintained for a given level of security. The interconnection enables all parties to pool their contribution to the primary frequency control and for each one to reduce the sizing of its own primary reserve both at the design level of generating units (in terms of frequency response) and in operational terms.

In situations when the recommended 2-hour or 15-minute margins (see above) cannot be met, a "Critical alert situation for insufficient margin" is actuated by RTE's national dispatch centre (CNES) and sent to all generators in accordance with the rules of the balancing mechanism.

### 5.2.7 Monitoring Security of Supply

RTE publishes a specific report each year on the outcome of power system reliability. The report details all major incidents, with a view to learning lessons from the experiences of these incidents. It is clear that the open and transparent nature of this reporting helps to engender a culture of reliability throughout the power sector.

## *5.3 Britain*

### 5.3.1 Background to the Electricity Sector in Britain

The electricity sector in Britain changed radically in 1990 when the electricity supply industry was privatised and competition introduced to both generation and retail supply. In recent years, the generation and retail markets have largely re-integrated, dominated by six major generator/retailers but include several smaller generators and a few independent retailers. Transmission and distribution are run as completely separate

[12] RTE, as system operator, does not enter in international power trading as such. Since 2000, the interconnector capacities are auctioned to participating power traders (previously EdF had monopoly use of these interconnectors).

businesses, although cross-ownership of distribution with generation/retail is not prohibited.

The total installed generation capacity in Britain is currently 77.5GW with an “average cold spell” maximum demand of 62GW. The generation mix comprises coal fired stations, combined cycle gas turbines plants running on natural gas, nuclear power stations, pumped storage plant, conventional hydro plant, open cycle gas turbines and an increasing percentage of renewable and embedded co-generation.

### 5.2.2 Overview of the British Electricity Market

Since 1990, the wholesale electricity market has evolved from a mandatory pool into a combination of a voluntary contract market and a mandatory balancing mechanism, which is now the international favoured pattern for developed electricity wholesale markets. The balancing mechanism is regulated and operated by the transmission system operator (National Grid). A completely separate and voluntary contract market, including a power exchange, operates outside the jurisdiction of the energy regulator although subject to financial regulation.

### 5.2.3 Security and Reliability in Britain

During 2003 there were two major customer interruptions that were transmission related, caused by inappropriate transmission protection settings by National Grid. There are currently concerns regarding the extent to which Britain will become dependant upon large quantities of imported gas (required as a fuel for the fleet of gas fired power stations built during the last decade) as indigenous gas supplies in the North Sea are now declining. The increased dependency upon imported gas has implications both for gas and electricity prices and for security of energy supplies. Serious consideration is now being given to the possibility of building new nuclear power plants.

A goal of the UK Government is that all customers can rely on secure supplies of energy. One of the ways in which Government achieves this is by providing good quality information on security of supply issues. The UK Government is concerned about all immediate and longer term security aspects of security of supply including:

- Sources of energy and their reliability;
- Power generation capacity;
- Energy storage and infrastructure; and
- Network resilience.

The above elements all contribute to the provision of safe and secure energy.

### 5.2.4 Forecasting Demand and the Supply/Demand Balance

The UK’s Energy Act 2004 requires the Secretary of State to report to Parliament annually on security of supply. The annual report, compiled jointly with the energy regulator, Ofgem, is required to cover the availability of electricity and gas for meeting the reasonable demands of consumers in Britain in the short and long term, including assessments of electricity generation, transmission and distribution capacity and gas infrastructure.

Security of supply is fundamental to the Government’s energy objectives. The UK’s Department of Trade and Industry (DTI) and Ofgem have shared statutory duties towards security of supply and have complementary roles in delivering it. The Government sets the overall policy direction and the regulatory environment. The structure, performance and regulation of markets are overseen by Ofgem, which also regulates monopoly businesses where necessary.

### 5.2.5 Determining the Reserve Margin

Since privatisation in 1990, a plant margin of 20% has been considered by National Grid as sufficient for meeting the peak demand although no specific generation reliability criterion currently exists. This compares with the 24% plant margin, which was used prior to privatisation in 1990 by the Central Electricity Generating Board in order to meet its security of supply obligations. This reduction in the plant margin for planning purposes reflects the improvement in the operational efficiency of generators (higher plant availability) and also the shorter lead times between construction and commissioning of plant due to changes in technology choice, largely because of investment in combined cycle gas turbines.

### 5.2.6 Managing System Security

The market framework creates strong incentives on participants to contribute to security of supply. The publication by National Grid of an annual outlook for the winter ahead also plays a key role in providing information to market participants and enabling them to take informed actions in the light of such information.

As regulator of the electricity industry and the onshore gas industry in Britain, Ofgem's principal objective is to protect the interests of gas and electricity customers in Britain, wherever appropriate by promoting effective competition. This objective is supplemented by specific 'security of supply' duties to have regard to the need to ensure that all reasonable demands for electricity and gas are met and to secure a diverse and viable long-term energy supply. The Secretary of State for Trade and Industry shares the duties with Ofgem and is accountable to Parliament on energy matters for Britain.

The legal and regulatory framework is geared towards ensuring that the owners of transmission and distribution systems provide efficient and timely investment to ensure sufficient network capacity and reliability so that available supplies of gas and electricity can be transported to energy customers. Within the price control allowances, licence obligations and incentives, overall decisions on network investment are determined by the transmission and distribution companies themselves.

National Grid plays a major role in ensuring security of supply by providing its balancing services. There are commercial incentives to ensure that, as monopoly service provider, National Grid responds efficiently and effectively to market signals and that its actions are sending appropriate signals to the market. National Grid is able to utilise the option of buying and selling electricity to keep the power system in balance, as well as entering into a number of other contracts for services. Following blackouts experienced in London and the West Midlands in 2003, Ofgem introduced a new electricity transmission network reliability incentive scheme for National Grid, reinforcing the existing obligations regarding network security. The incentive scheme came into effect in January 2005.

In July 2001, DTI and Ofgem set up the Joint Energy Security of Supply working group (JESS) to assess risks to Britain's future gas and electricity supplies. The remit of the JESS group is to:

- Assess the available data relevant to security of supply and to identify the gaps in that data and develop appropriate indicators;
- Monitor at a strategic level, over a timescale of at least seven years ahead:
  - the availability of supplies of gas;
  - the availability of supplies of electricity and fuels used for electricity generation;
  - the adequacy of generating capacity; and
  - the adequacy of the UK's gas and electricity infrastructure.
- Assess whether appropriate market-based mechanisms are bringing forward timely investment and to address any weaknesses in the supply chain that are anticipated;
- Identify relevant policy issues and consider implications; and
- Report twice yearly to the Secretary of State.

The JESS group, chaired jointly by DTI and Ofgem brings together contributions from the DTI, Ofgem, National Grid and the Foreign and Commonwealth Office on energy security. The work that JESS undertakes on security of supply is focused on the medium to long-term, at least seven years ahead, rather than the short-term.

JESS seeks to present market information rather than to draw firm conclusions, as much of this information is capable of being interpreted in a range of ways. Within the bounds of commercial confidentiality, JESS aims to ensure that energy companies, investors and consumers have access to as wide a range of information as possible.

### 5.2.7 Monitoring Security of Supply

In a market-based system such as that in the UK, the provision of adequate energy supplies to meet demand depends on effective market responses, which in turn relies on market players having accurate information to inform their expectations about future prices. Every year National Grid produces a "Seven Year Statement" which provides a view of the supply demand situation in Britain and includes a calculation of future reserve margins under a number of scenarios.

The UK is required by the European Union (EU) Gas Internal Market Directive (Directive 2003/55/EC of 26 June 2003 to monitor gas security of supply issues and to publish a report each year; and by the EU Electricity Internal Market Directive (Directive 2003/54/EC of 26 June 2003) to monitor electricity security of supply issues and to publish a report every two years.

The Commission proposed an Electricity Security of Supply Directive at the December 2003 Energy Council. The proposal requires Member States to clarify the roles and responsibilities of market participants in safeguarding security of supply, taking account of:

- The importance of ensuring continuity of electricity supplies;
- The importance of a transparent and stable regulation framework; and
- The internal market including possibilities for cross-border cooperation.

Transmission and distribution system operators must meet network security and quality of supply standards. Member States of the EU must take appropriate measures to maintain a balance between demand and availability of generation capacity, in particular by encouraging the establishment of a wholesale market that provides price signals for generation and consumption.

DTI/Ofgem investigations into the blackouts experienced in 2003 in the USA/Canada, Italy and Sweden/Denmark, concluded that while similar experiences are unlikely in the UK, maintenance and asset management are crucial to avoid increases in the number of concurrent fault events that would risk more and larger supply interruptions to consumers.

One of the key tasks for the JESS group has been to establish a series of indicators to monitor security of supply. These indicators include:

- Supply and demand forecasts (for both gas and electricity).[13]
- Market signals (forward prices for both gas and electricity).
- Market response (the responses by market participants to the forward price signals).

## *5.4 North America*

Historically, decisions on the amounts, locations, types, and timing of investments in new generation were made by vertically integrated utilities with approval from state public utility commissions. As the electricity industries in both the USA and Canada have been restructured, these investment decisions have been fragmented and dispersed among a variety of organisations.

Because of the significant amount of interconnection between the USA and Canada, the power systems in the two countries operate under the auspices of the North American Reliability Council (NERC), with ten regional reliability councils. Generation utilities divide their generation reserves into two categories, related to the differences between short-term security and long-term adequacy. For day-ahead planning and real-time operation, utilities are required by the NERC and the regional reliability council rules to maintain minimum levels of operating reserves (typically 4% to 8% of the projected daily peak). These short-term reserves protect bulk-power systems from the effects of major generation and transmission outages and correct for errors in day-ahead load forecasts. Planning reserves (of which operating reserves are a subset) provide long-term insurance against problems that might otherwise arise when generating units are not available and allow for unanticipated long-term load growth.

NERC is a non-governmental entity whose mission is to ensure that the bulk electric system in North America is reliable, adequate and secure. The organisation was established in 1968, as a result of the Northeast blackout in 1965. Since its inception, NERC has operated as a voluntary organisation, relying on reciprocity, peer pressure and the mutual self-interest of all those involved to ensure compliance with reliability requirements. An independent board governs NERC.

NERC undertakes the following functions:

[13] The plant margin is widely used as a broad indicator of security of electricity supplies although it does not capture fully all the factors that may have an impact on the reliability of energy supply.

- Sets standards for the reliable operation and planning of the bulk electric system;
- Monitors and assesses compliance with standards for bulk electric system reliability;
- Provides education and training resources to promote bulk electric system reliability;
- Assesses, analyzes and reports on bulk electric system adequacy and performance;
- Coordinates with Regional Reliability Councils and other organizations;
- Coordinates the provision of applications, data and services necessary to support the reliable operation and planning of the bulk electric system;
- Certifies reliability service organizations and personnel;
- Coordinates critical infrastructure protection of the bulk electric system; and
- Enables the reliable operation of the interconnected bulk electric system by facilitating information exchange and coordination among reliability service organizations.

NERC and its ten Regional Reliability Councils have developed system operating and planning standards for ensuring the reliability of a transmission grid that are based on seven key concepts:

- Balance power generation and demand continuously;
- Balance reactive power supply and demand to maintain scheduled voltages;
- Monitor flows over transmission lines and other facilities to ensure that thermal limits are not exceeded;
- Keep the system in a stable condition;
- Operate the system so that it remains in a reliable condition even if a contingency occurs, such as the loss of a key generator or transmission facility (the “N-1 criterion”);
- Plan, design, and maintain the system to operate reliably; and
- Prepare for emergencies.

Recent changes in the electricity industry have altered many of the traditional mechanisms, incentives and responsibilities of the entities involved in ensuring reliability, to the point that the voluntary system of compliance with reliability standards is now generally recognised as being inadequate to ensure the reliability of the interconnected transmission systems because of the competition among firms in the market. NERC encourages compliance with its reliability standards through an agreement with its members. In the absence of federal legislation requiring compliance with reliability standards, NERC has limited ability to enforce its reliability rules.

In 2005, a new Energy Policy Act was passed by the USA Government. One of the new requirements from the 2005 Energy Policy Act is that FERC has jurisdiction over bulk electricity reliability, with powers of enforcement not held previously. The new Act requires the establishment of an Electric Reliability Organization (ERO), which will be certified by FERC and have the responsibility to enforce reliability standards. Currently, NERC is positioning itself to be the ERO. The fundamental change will be from a non-mandatory NERC to a mandatory ERO, with powers to enforce reliability standards.

NERC’s members are the ten Regional Reliability Councils. The regional councils and NERC have opened their membership to include all segments of the electric industry (investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers). The ten regional councils jointly fund NERC and adapt NERC standards to meet the needs of their regions.

Utility industry restructuring has led to an unbundling of generation, transmission and distribution activities such that the ownership and operation of these assets have been separated either functionally or through the formation of independent entities called Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs).

ISOs and RTOs have been authorized by FERC to implement aspects of the Energy Policy Act of 1992 and subsequent FERC policy directives. The primary functions of ISOs and RTOs are to:

- Manage in real time and on a day-ahead basis the reliability of the bulk power system and the operation of wholesale electricity markets; and
- Operate or direct the operation of the transmission assets owned by their members.

Control area operators have primary responsibility for reliability. Each Area's risk of disconnecting any firm load due to generation deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting firm load due to generation deficiencies shall be, on average, no more than 0.1 day per year[14].

Two examples of the approaches adopted by the Pennsylvania- New Jersey- Maryland (PJM) and New York ISOs to comply with this requirement are given below.

**PJM:**
The PJM Reliability Assurance Agreement (RAA) obliges all Load Serving Entities (LSEs) within the PJM control area to provide the amount of installed generating capacity that PJM determines is required to maintain reliability. The PJM Reliability Committee determines the reserve margin using probabilistic methods. The margin is intended to ensure a sufficient quantity of generation capacity to meet the forecast load plus reserves adequate to provide for the unavailability of generation, load forecasting uncertainty, and planned outages. The focus is on the peak season, which for PJM overall is the summer.

In October 1998, PJM established monthly Capacity Credit Markets to allow PJM market participants to buy and sell capacity credits to meet their obligations under the RAA. Any PJM member that has PJM qualified resources or is an LSE must bid into these markets.

**NYSO:**
The New York State Reliability Council (NYSRC) is responsible for establishing a state wide annual Installed Capacity Requirement. The New York ISO approach to installed capacity requirements is similar to that of the PJM. The capacity requirement is to ensure adequate resource capability in New York State with the probability of disconnecting firm load due to generation deficiency, on average, no more than once in

[14] 0.1 days per year is equivalent to 1 day in 10 years.

ten years. The NYSRC Agreement states that the NYSRC shall establish the annual Installed Capacity Requirements (ICR) for New York State consistent with NERC and Northeast Power Coordinating Council (NPCC) standards.

## *5.5 Texas*

Whilst the above section outlines the responsibilities for ensuring security of supply in North America in general, this section focuses specifically on how security of supply is implemented within the State of Texas.

### 5.5.1 Background to the Electricity Sector in Texas

The electricity sector in Texas is, in some ways, similar to that of South Africa. It covers a large geographic area and has a large proportion of the load concentrated in the north-central region of the State. Whilst it does not have a single dominant electric utility, there exist a number of municipal suppliers and co-operatives, in addition to the investor-owned utilities. Since retail competition was introduced in 2002, power marketers, independent generators and independent retailers have joined as market participants.

Although loosely referred to as the Texan market, these notes refer to the synchronously interconnected system within Texas, managed by the Electric Reliability Council of Texas (ERCOT), which covers 75% of the area of the State and 85% of the State's electricity load (ERCOT excludes the El Paso area and other fringe areas of Texas). ERCOT is unusual in that, unlike the other regions of USA and Canada, there is no synchronous interconnection with any other region or country[15]. Thus, ERCOT functions as both a reliability council and an independent System Operator (ISO) for the ERCOT region. From 2002, ERCOT is also responsible for the operation of the liberalised wholesale electricity market in the ERCOT region. The ERCOT organisation is a not-for-profit company, owned and governed by its members.

The ERCOT system currently has around 78 GW of generation capacity, predominantly natural gas fired (both steam turbine plant and combined cycle) plus coal, nuclear and renewable fuel.

### 5.5.2 Overview of the Texan Electricity Market

Texas has one of the most successful competitive electricity markets in North America, initiated in 2002, following a State law that enabled full retail competition and liberalisation of the wholesale market. It was decided to use the existing Independent System Operator, ERCOT, to perform the functions of a wholesale market operator, in addition to its existing ISO function. The ERCOT market is unique in that it incorporates a central customer registration database, to maximise the efficiency of customer switching between competing retailers.

ERCOT is responsible for the following functions:

- Grid operations and system reliability.
- Wholesale market administration.
- Competitive retail market administration.
- Co-ordination of Transmission planning.

[15] ERCOT has DC links with other States and Mexico but the capacity of these links is relatively small, thus, effectively, ERCOT has to provide its own reserve margin.

- Administration of the Renewable Energy Credit Program (incentives for renewable power generation).

Under the Texan State Law that enabled market liberalisation and retail competition (1999 Senate Bill 7), ERCOT is assigned the following obligations:

- Ensuring open access arrangements to transmission and distribution systems (ERCOT leads and facilitates three regional transmission planning groups).
- Ensuring reliability and supply security.
- Enabling customer choice by the provision of information to support retail switching.
- Accurate accounting for electric production and delivery.

In pursuance of its obligations, ERCOT has to comply with:

- The State Law (1999 Senate Bill 7).
- National Electric Reliability Council (NERC) guidelines for reliability and security standards.
- Regulatory requirements, as set by the State regulator – the Public Utility Commission of Texas (PUCT)[16].
- ERCOT protocols, guides and rules, as determined by ERCOT membership.

In addition to regulatory control by the PUCT, ERCOT is subject to oversight by the Texas Legislature (state parliament).

The ERCOT market consists of a market for balancing energy and a number of separate ancillary services markets. Reserve capacity is provided as part of the ancillary services market, based on a marginal price auction. Ancillary service costs are allocated to market participants according to their energy demand. Participants may either source their own ancillary services or bear the cost from the market. There is no separate day-ahead or spot market. Congestion management is based on 5 zonal prices and transmission congestion rights are tradable.

### 5.5.3 Responsibility for Security and Reliability of Supply in Texas

It is interesting to note that, whilst ERCOT does not itself assume a position on matters of policy, the exception to this is the area of system reliability, where ERCOT ensures that any proposals will not have a negative impact on reliability.

In the United States of America, the National Electric Reliability Council (NERC) is a non-mandatory organisation that sets standards for reliability and security. ERCOT, as a member of NERC, is required to meet the NERC standards. In addition, ERCOT sets its own protocols, which generally are more stringent than the NERC standards.

[16] The United States of America has a Federal Energy Regulator – FERC; and each State has its own utility regulator. The responsibilities of FERC extend to inter-regional transmission flows but, since Texas is physically separate from the rest of mainland USA, FERC's jurisdiction does not cover transmission within the ERCOT region.

A separate division within ERCOT, reporting directly to the CEO, is responsible for monitoring compliance with the reliability and security standards, thus ensuring that the monitoring of compliance is kept separate from operations.

### 5.5.4 Forecasting Demand and the Supply/Demand Balance

Demand forecasts are developed by ERCOT centrally, taking into account local forecasts provided by transmission service providers. The forecast peak demand is adjusted to take account of price response.

ERCOT produces an annual report on generation and transmission expansion plans – "Report on Existing and Potential Electric System Constraints and Needs", giving details of plans and proposals by utilities for projects within the ERCOT region. This provides a focus for determining the likely level of the supply/demand balance, throughout ERCOT and at a regional level based on three planning regions and the market congestion zones. As part of this planning process, ERCOT has recently been mandated by specific legislation to provide adequate transmission capacity for some 5000 MW of renewable generation for Texas.

### 5.5.5 Determining the Reserve Margin

The reserve margin is defined as the difference between the forecast load and the total resources available. The resources available are defined to include all generation installed in the ERCOT region (10% of capacity for wind turbines) plus capacity available from DC tie-lines plus contracted interruptible loads, less any plant declared as retired or mothballed.

Following the liberalisation of the Texan market, some 27 GW of new generation capacity was built in the ERCOT region, leading to reserve margins of 20-30%. However, recent plant retirement and mothballing (some 7 GW) has resulted in much lower margins, raising concerns about security of supply. It is now forecast that the reserve margin will reduce to 11.4% by 2010, compared with a minimum of 12.5% regarded as necessary to ensure supply security. The level of 12.5% is set by the ERCOT Board.

### 5.5.6 Managing and Monitoring System Security

As an illustration of the management of system security, details of a recent outage event on 17 April 2006 was provided to the State Legislature and published on the ERCOT website within a week of the event. These details show how ERCOT responded to a most unusual event, where 5 separate generating units tripped during the day, resulting in the loss of load for a few hours. The report includes details of how the system responded and what lessons can be learnt from the event, for implementing future improvements.

An improvement in the management of congestion costs has resulted from a recent change to dynamic rating of transmission lines. Previously, transmission lines were rated thermally based on a conservative "worst-case" view of temperature, whereas now, ratings are varied hourly according to actual temperature conditions. This is estimated to have saved around US$ 30 million per year.

## 5.6 Australia

### 5.6.1 Background to the Australia's National Electricity Market

The electricity sector in Australia is in many respects similar to that of South Africa. Geographically, both countries have large rural areas and concentrations of population in a relatively small number of cities. Australia has almost the same electricity consumption as South Africa (circa 200 TWh p.a.) and is dependent on coal for 84% of its generation. In Australia, two-thirds of the generation and over half the transmission and distribution remains state-owned (by the State Governments). However, despite the large proportion of state ownership, Australia has moved to a competitive market solution to meeting its energy requirements.

The National Electricity Market consists of the interconnected regions of Australia (i.e. all parts of the country with the exception of Western Australia and Northern Territory, which are physically very remote from the rest of the country). Thus, the NEM consists of the States of Victoria, New South Wales, Queensland, South Australia and Tasmania and the Australian Capital Territory (Canberra area). The NEM is managed by a not-for-profit company, the National Electricity Market Management Company (NEMMCO), funded by fees charged to market participants.

Until recently, regulation of Australia's power sector existed only at the State level. Each State had its own Essential Services Commission, responsible for regulation of energy and water services. However, in 2005 the Australian Energy Regulator (AER) was established, taking responsibility for regulation of the NEM and, from 2007, for network pricing in each interconnected State.

### 5.6.2 Overview of Australia's NEM

Established in 1996, the NEM provides integrated market and system operator functions for the market participants – generators and retailers. Transmission and Distribution Network Service Providers (NSPs) provide the means of access via their respective "wires" businesses. In Australia, joint ownership of generation and retail businesses is not permitted, so there has not been the integration of generation and retail functions seen in Britain and New Zealand.

The NEM operates a continuous spot market for power, based on generators' offers to supply power, with a maximum price set by the market, currently at A$10,000/MWh, also known as the Value of Lost Load (VoLL), triggered automatically whenever it becomes necessary for NEMMCO to issue a notice to NSPs to disconnect load in order to maintain a balance between load and generation available.

Although NEM prices are set primarily by generators' offers, the market provides for demand-side participation in the following ways:

- The ability of market customers to respond to prices by reducing consumption at times of very high spot prices.
- Demand-side bidding, where certain scheduled loads (e.g. smelters) can elect to withdraw from the market when the spot price reaches pre-determined levels and to resume when the price falls.
- Load shifting, where specified demand is shifted to a period of lower spot prices (e.g. off-peak water heating).

NEMMCO also operates eight separate markets for frequency control ancillary services (FCAS) and purchases network control ancillary services (NCAS) under contractual agreements with service providers. FCAS providers bid their services into the markets in a similar way to the generators' energy bids. Payments are made for availability and delivery of ancillary services. FCAS bidding was introduced into the NEM in 2001 and provides simpler, more dynamic and transparent mechanisms that have increased competition and enhance overall efficiency.

### 5.6.3 Security and Reliability in Australia's NEM

Reliability standards are determined in the NEM based upon ensuring that expected unserved energy in each year for each region is not more than 0.002% of the total energy consumption for that year for that region.

In order to meet the required standard of system reliability, NEMMCO is required to ensure that a minimum of 850MW of reserve is carried across the entire NEM, including times of peak demand.

In all but extraordinary circumstances, market forces keep supply and demand in the NEM in balance. However, during periods of supply shortfall, NEMMCO is able to use the following means to restore balance:

- NEMMCO has powers to direct generators into production when a shortfall is expected and some generators are known to have withheld some capacity from the market.
- Disconnection - NEMMCO can instruct Network Service Providers to disconnect load where there is a need to reduce demand in order to restore balance, resulting in supply interruptions to customers. This load shedding process is undertaken because system security has a higher priority than reliability in a particular region. During a period of load shedding, supply is withdrawn from those NEM regions affected by the shortfall in proportion to each region's demand up to the point where the interconnectors are operating at maximum capacity. Thereafter, each region has the bear any additional load shedding.
- Reserve Trading - When there is sufficient notice, NEMMCO may tender for contracts to supply from sources beyond those already accounted for in the NEM, such as emergency generators connected to the distribution networks or customer demand reduction contracts.

### 5.6.4 Forecasting Demand and the Supply/Demand Balance

Generators and network operators are required to notify NEMMCO of their maximum supply capacity and availability, which is matched against regional demand forecasts. This information is used by market participants for re-bids into the market. In addition, NEMMCO monitors the future adequacy of generating capacity based on a projection of availability and demand forecasts:

- The Short-term Projection of System Adequacy (PASA) is a weekly assessment, over the following seven days; and
- The Medium-term Projection of System Adequacy (PASA) looks ahead over the next two years.

- The Statement of Opportunities (SOO) is published by NEMMCO each year, providing an assessment of the need for generation, demand-side participation and network augmentation over the following 10 years. The SOO contains details of existing and planned generation plant, information about inter-regional transmission capacity, technical limits on networks, ancillary service requirements, minimum reserve levels and other economic and operational data.
- An Annual National Transmission Statement is published in conjunction with the SOO, showing current and future major power flows.
- An annual supply-demand balance is presented for each region of the NEM to provide a snapshot of the capacity of generation and networks to meet projected demand on a regional basis.

### 5.6.5 Determining the Reserve Margin

As stated above, the existing reliability standards are determined so that unserved energy in each year for each region is not more than 0.002% of the total energy consumption for that year and region. The reliability level was set on the basis of expected unserved energy, in order to reflect the customer impact. However, in order to monitor the adequacy of the system to meet this reliability criterion, the reserve margin corresponding to the reliability standard is used. The Reliability Panel stated that reserve thresholds were to be based on the *greater of either*:

- The amount calculated to meet the unserved energy standard; and
- The largest single contingency in each NEM region (using the peak load having a 10% probability of being exceeded).

NEMMCO has conducted a number of studies into the size of reserve margin that would be required, in each NEM region, to support this level of reliability.

The reliability standard in the NEM is determined by a Reliability Panel (a panel of experts). The reserve margins, for each NEM region and the NEM in aggregate, are calculated based on two levels of peak demand:

- A level of peak demand based on a 50% probability of being exceeded (which is the usual basis for the measure of reserve margin internationally); and
- A level of peak demand based on a 10% probability of being exceeded (which is a useful sensitivity to consider for the peak demand forecast).

In the calculations, interruptible load and other demand-side generation equivalents are added to generation capacity or subtracted from the forecast peak demand to calculate the reserve capacity, from which the reserve margin is calculated as a percentage of the peak demand. A calculation, in 2004, showed the levels of reserve margin in the aggregate NEM of 6% at the 10% probability level and 13% at the 50% probability level. However, when allowing for inter-regional peak demand diversity, the reserve margins increase to 12% and 19% respectively.

### 5.6.6 Monitoring Security of Supply

One of the most important inputs to the measure of system reliability is the expected outage rate for generating units. These rates are known to vary with age of plant, generally following a so-called “bath-tub” curve, where forced outage rates reduce after the first few years of operation, followed by a relatively stable period and then by a period of increased outage rates as equipment gets older. A recent NEMMCO report has recommended improvements to the existing outage reporting system operated for the NEM. These recommendations include:

- Detailed generator forced outage reports on an individual event basis, including data on partial outages (i.e. outages that cause a partial loss of generation availability, rather than the full loss).
- Use of a compensation factor in the reliability calculations, based on data from outage reports.
- Model a set of generator forced outage statistics for a period of 6-10 years.
- Compare outage data for selected generators against their public domain output and bidding data.

## *5.7 International Generation Security Standards*

Typical levels of reserve margin encountered in power systems internationally are in the range 15% - 25%. A typical breakdown of the make-up of the reserve margin requirement is:

- Covering unplanned generation outages (3% - 13%, depending on factors as described above).
- Operating reserves to meet instantaneous changes in demand (3%).
- Providing for extreme weather variations (5%).
- Allowing for higher demand growth (5%).

The following information on international generation security standards has been extracted from the DataMonitor report provided by Eskom and other research.

**Table 1 – International Generation Security Standards**

| Country | Utility/Market | Probabilistic Security Standard | Deterministic Security Standard | Notes |
|---|---|---|---|---|
| USA | Florida Power and Light | LOLP<br>0.1 day per year | Reserve margin 20% firm capacity above system peak load | Increased the reserve margin from 15% to 20% summer 2004 |
| USA | New York | LOLE<br>0.1 event per year (1 event in 10 years) | | Annual assessment of system reliability |
| USA | SDGE/California | LOLP/CoUE | | SDG&E can assess the actual reserve capacity required for any stipulated system reliability measurement |
| Mexico | CFE | None | Reserve margin 27% reserve (6% operating reserve, 15% plant availability, 6% outages) | Local requirements also considered, against grid capacity |

| Country | Utility/Market | Probabilistic Security Standard | Deterministic Security Standard | Notes |
|---|---|---|---|---|
| Thailand | | LOLP should not exceed 1 day per year | Reserve margin of 15% | Margin reduced from 25% in line with economic recession in the later 1990s |
| Malaysia | | LOLP 1 day per year | | |
| France | | LOLE not more than 3 hours per year on average, consistent with one shortfall every ten years | | |
| Britain | | No specific criterion | No specific criterion | Before privatisation, 24% reserve margin was used for planning |
| Australia | | | 12% or 19% reserve margin at 10% and 50% probability levels respectively | |

## *5.8 Summary of the International Perspective*

The importance of power system security has increased significantly in recent years, following large-scale power outages in North America and Europe. There is a much stronger focus on security of supply, with explicit security standards being set. Among other issues, it has become evident that maintenance and asset management are crucial to avoid increases in fault events that risk more and larger customer interruptions.

A consistent trend in most other countries is that the traditional approach of leaving security to be managed by a utility has been replaced by a transparent and inclusive process, with Governments and Regulators taking a pro-active position.

The international norm is that detailed information on plant availability; analysis of major outages; and plans and proposals for generation and transmission augmentation; is in the public domain, rather than kept confidential to utilities.

# 6 Security of Supply in South Africa

## 6.1 Generation

While is generally assumed that Eskom has the main responsibility for the security of supply in South Africa, since it owns and operates the vast majority of existing generation plant, there is a lack of clear direction regarding responsibility for security of supply, particularly under the current policy whereby Eskom's new generation capacity build is limited to 70% of total new capacity. It is noted that, when inviting expressions of interest for the first IPP project in December 2004, the Department of Minerals and Energy (DME) stated that "Eskom will be responsible for meeting the capacity requirement in the short term while the DME will ensure that 1,000 MW of peaking power generation is commissioned by the end of 2008"[17]. Thus, it would appear that the overall responsibility for supply security lies with the DME but that, in the short-term, Eskom has an obligation to meet the need for additional capacity. At a DME energy workshop in May 2006, the Minister for Minerals and Energy reaffirmed that she was ultimately responsibility for security of supply. However, there is no agreed basis or standard for the level of supply security to be provided. In the short-term, this may be somewhat irrelevant, as Eskom is currently responding to a critical shortfall in its generation capacity, partly due to the Koeberg problems but also to the fact that the reserve margin has fallen to record low levels compared with the historic situation.

In the medium to longer term, there is a need, first to determine a security standard, to define what level of reserve margin should be maintained and second, to clarify the responsibility for meeting that security standard under the 70/30 new capacity policy. In the absence of such clarity, Eskom's Corporate Plan[18] appears to assume that Eskom will need to build all of the additional new generating capacity required, apart from the peaking IPP plant currently out for tender. Eskom's Corporate Plan is based on an "Extra High Forecast" (6% GDP growth; 4.4% electricity growth p.a.), which would require the need for a Combined Cycle Gas Turbine (CCGT) generating plant and the first two units of a new coal-fired power plant to be built by 2010, in addition to the existing plans for Open Cycle Gas Turbine (OCGT) peaking generation plant and the return to service of the mothballed plant. The Corporate Plan notes, however, that by 2010, with all of this new plant commissioned, the reserve margin would be only 5% on the "Extra High Forecast", compared with 20% using the "moderate" growth forecast in ISEP10.

Given the uncertainties and risks associated with the demand forecasts and the capacity construction programme, it is crucial to determine how the responsibility for supply security is to be discharged given the 70/30 policy at the earliest opportunity.

## 6.2 Transmission

Since Eskom is the only licensed Transmission System Operator (TSO) in South Africa, the responsibility for ensuring that the transmission system meets the required security standards lies firmly with Eskom. This responsibility has two aspects:

[17] Quoted in Business Day, 9 December 2004.
[18] Eskom Holdings Business Plan 2007 – 2011 (Confidential), March 2006.

- For transmission system design, to plan and construct sufficient transmission capacity to ensure that the design standard is met at all locations on the South African Grid. It is understood that the current design standard is the internationally recognised “N-1” standard, meaning that supplies would not be interrupted in the event of a single outage. However, for any transmission reinforcement required to meet the N-1 criterion, a business case has to be made before such reinforcement can proceed. As a result, not all of the transmission system meets the N-1 criterion.
- For transmission system operation, the responsibility for system security is identified in the South African Grid Code, which includes the obligation to operate the system such in the event of the most severe double outage, so that there is no instability, uncontrolled operation or cascading[19] outages on the system. Compliance with the South African Grid Code is managed by NERSA under its Transmission Compliance Monitoring Framework. The reliability performance of the transmission system for the year 2004 is published by NERSA.

Thus, there would appear to be reasonable clarity for the expected level of system security. However, the recent outages in the Western Cape suggest that the situation is somewhat more complicated than suggested by the above. Transmission issues and the recent experiences in the Cape region in particular, are discussed in section 6.10.

## *6.3 Distribution*

Although recent supply interruptions are due to generation and transmission outages, generally it is distribution networks that are the most unreliable part of the supply chain. This is due to the economics of distribution, particularly at lower voltages, which largely preclude an “N-1” approach, except for major substations and particular secure supplies. In recent years, a large number of distribution network outages have caused widespread supply interruptions in major cities in South Africa. To customers, an interruption is an interruption, whatever the cause. It is important, therefore, to ensure that distribution network reliability is maintained at appropriate levels, according to the size and nature of the supply. Provided that generation and transmission security is maintained at appropriate levels, it is to be expected that distribution networks will cause the largest component of the average interruptions per customer and the average customer minutes of supply lost in any year. Thus, in addition to generation and transmission, distribution networks should be a major focus for monitoring security and reliability. In is noted that while faults on overhead distribution lines can usually be repaired relatively quickly, failures to aging underground cables can result in extended outages in city centres as, for example, was experienced a number of years ago in Auckland, New Zealand. This study, however, is limited to a discussion of generation and, to some extent, transmission, security.

The responsibility for distribution network security is with the individual distribution network operators – Eskom Distribution Division and the various Municipalities. NERSA is responsible for managing compliance with the required standards via the distribution licences.

[19] Cascading outages result from several automatic disconnections of generating units, such as occurred during the North American outage in August 2003.

## *6.4 Demand Forecasting Issues*

### 6.4.1 Demand Forecast Timescales

Due to the long lead times associated with building new generation plant (and, to a lesser extent, with transmission system augmentation), the ability to forecast the demand for power over the short, medium and longer term, is crucial to meeting security of supply requirements economically and effectively. A demand forecast that understates the future demand growth is likely to lead to a shortfall in capacity required built to meet the demand, whereas an over-stated demand forecast is likely to lead to a surplus, with consequent cost implications for customers. It is not only the overall level of demand growth that needs to be predicted accurately but it is also important to identify the geographic and demographic trends in demand growth, since these will impact on the economics of generation plant expansion and the requirements for transmission and distribution system expansion.

### 6.4.2 Demand Level and Shape

Much of the focus of demand forecasting is on the annual level of peak demand on the integrated system (i.e. the highest simultaneous aggregate kW demand level in any given period, usually a year). However, whilst the level of peak demand is the most critical for establishing the capacity requirements to meet the peak, it is necessary to consider also the demand for power at other times of the year, on a seasonal and daily basis. Thus it is important to be able to predict accurately the shape of demand over the year, in addition to the peak level. Forecasting the overall annual level of consumption (kWh) is an important and generally, a prior, step to forecasting demand but this in itself will not provide a forecast of the demand shape throughout the year. Assuming that the existing load shape will prevail and concentrating entirely on peak demand and annual consumption levels is likely to lead to sub-optimal choices of generation plant and may cause supply security to be at risk in certain periods of the year outside the annual peak. For example, if the demand level is less “peaky” than forecast, with long periods of demand close to peak levels, there may be a need for greater use of peaking plant, perhaps over and above its design parameters. On the other hand, if out-turn demand is more “peaky” than forecast, this may lead to the need for more base-load plant to operate increasingly in load-following mode, which may be inefficient.

### 6.4.3 Demand Forecasting Purposes

Demand forecasts are used for two different purposes. Medium to long term demand forecasts are used to develop an economic expansion plan for future new build and plant retirement scheduling. Short term demand forecasts are used to operate the existing system in the most economic and effective manner, taking into account short-term positions on plant availability, the fuel situation and transmission constraints. Whilst there is no firm demarcation, short-term forecasts usually relate to hourly, daily, weekly and within year timescales, whereas medium to long term demand forecasts are usually for periods of a year ahead and beyond.

This study focuses on the medium to long term demand forecasting, since this is used for system expansion planning purposes and is most relevant to the determination of a reserve margin.

### 6.4.4 Demand Forecast Accuracy

It is good practice to check the accuracy of demand forecasts periodically. In doing so, it is necessary to ensure that appropriate comparisons are carried out. For example, if the focus is on a short-term demand forecast, say day-ahead or week-ahead forecasts for plant scheduling purposes, the appropriate comparison is between the forecast and actual demands over these timescales. On the other hand, to check the accuracy of long-term demand forecasts used for system expansion planning, it is appropriate to compare forecast and actual annual demands over a long-term timescale. For example, a typical comparison would be between forecasts made 5-10 years ago with the actual demand level for each year. Comparing year-ahead demand forecasts with actual demands is not adequate for this purpose.

No forecast can ever be entirely accurate and any forecast will have an associated margin of error, which can be determined statistically, on the basis of uncertainties in the input parameters. A good demand forecast should meet all of the following conditions:

- The actual demand should fall within the margins of error of the forecasts;
- The difference between the forecast level of demand and the actual level should be capable of explanation, by reference to differences between the forecast assumptions and actual out-turn conditions (e.g. weather and economic effects).
- There should be no inherent bias in the forecast, so that, the average deviation between forecast and actual level of demand should be close to zero, with some years being positive and others being negative.
- The forecast should be capable of adapting to actual demands, so that, as each new actual demand is recorded, the demand forecast is adjusted to take account, if necessary, of the most recent actual demands.

### 6.4.5 Approaches to Demand Forecasting

Two different approaches are commonly employed for electricity demand forecasting:

- A “Bottom-up” approach, utilising detailed data of separate demand sectors and individual large loads, together with expectations of how each sector and large load will change over time, in relation to individual sector drivers such as population and habitation trends, manufacturing production levels, electrical appliance ownership, energy efficiency, and sector price elasticity; and
- A “Top-down” approach, which depends strongly on the correlation between electricity demand and economic drivers, particularly GDP and others such as population growth.

In practice, most utilities and demand forecasting agencies use a combination of both approaches. The two approaches are not in fact mutually exclusive, since the “bottom-up” approach usually involves the application of historically observed correlations between sector growth and certain key econometric variables such as manufacturing production indices[20]. The “Top-down” approach, however, lends itself more easily to sensitivity testing against changes in the main input drivers. Due to the way demand forecasts are constructed in this approach, it is relatively easy to show how the demand

[20] In using the “top-down” approach, it is most important to use appropriate statistical techniques to avoid problems of multiple correlations between the variables and be able to identify which are the causal drivers. This is a common mistake with “top-down” demand forecasting.

forecast changes with changes to the assumptions on GDP growth and other main drivers. Sensitivity tests can also be carried out with “Bottom-up” demand forecasting but this requires the sensitivity to be applied through the particular drivers for each sector and it is not always clear how these will interact. For example, where the demand forecasts for the residential sector is built up from inputs on household size, appliances ownership and population trends, it may not be clear how these variables will move in relation to changes in assumptions on GDP growth. Thus, demand forecasting is a complex business, which requires a combination of detailed knowledge of each demand sector, an understanding of how the main econometric variables impact on demand and an appreciation of how the consumption patterns may change over time as new technologies impact on consumption.

### 6.4.6 Price Elasticity and Energy Substitution

It is theoretically possible to measure the effect of price elasticity for certain major sectors and apply this as one of the drivers for sector demand. However, this approach is difficult, as price elasticity varies hugely between sectors and within sectors. Fortunately, the impact of price elasticity is only significant for certain energy intensive industries and for certain types of consumption where there exists the possibility of substitution (for example, the use of gas for water or space heating). Applying price elasticity effects requires assumptions to be made about future price movements (in real terms), which, in part is affected by the demand growth and cost of meeting that growth through expansion plans. It is therefore important to be careful about where in the demand forecasting process such effects are applied.

### 6.4.7 Energy Efficiency and Demand-side Management

Consumption levels and demand shape can be affected significantly by changes in the efficiency of energy conversion at the point of use (energy efficiency) and the particular application of other demand-side measures designed to influence the level and shape of demand. In forecasting electricity demand, it is most important to avoid double counting in this respect. Generally, changes in energy efficiency are best built into a sector forecast, in conjunction with other drivers such as new technologies and customer consumption patterns. Otherwise, it becomes unclear as to how energy efficiency changes will impact on sector demand. Similarly, some demand-side measure based on incentive pricing to change demand patterns may already have been taken into account via a price elasticity input.

Where energy efficiency and demand-side measures are identified as separate adjustments to demand or as alternatives to generation capacity, great care is required to avoid such double counting and also to ensure that the levels of demand reduction are realistic in terms of what can be achieved in practice.

### 6.4.8 Environmental Issues

Demand may be influenced significantly by changes in legislation, public attitudes or corporate policies regarding the impact of electricity consumption on the environment. Where certain changes are known to be planned to take place, it is prudent to make allowance for the relevant changes in the demand forecasts but with appropriate sensitivity tests to identify the impact. Where changes are under consideration, the effects on electricity consumption may be included as part of the sensitivity tests.

### 6.4.9 Weather Effects

In addition to the drivers described above, weather is known to have a significant effect on electricity demand, particularly in markets such as South Africa where electricity is used for heating and air-conditioning. Demand forecasts are usually prepared on the basis of “normal weather”, meaning that the demand forecast figures relate to average long-term temperatures occurring at relevant times of the year. In order to relate historic data to the input drivers, it is necessary to apply a correction to actual demand data to change the actual demand levels (up or down) to what would have been expected had “normal weather” conditions applied. This requires a detailed model of the impact of weather on demand and one that is capable of reacting to changes in the impact, as customer consumption patterns and responses to weather effects vary over time.

In addition to a demand forecast on the basis of “normal weather”, it is usual to develop scenarios or sensitivity tests with variations such as cold or mild weather. However, whilst fairly extreme variations can be expected in weather from year to year, it is unlikely that abnormally cold or mild conditions would apply throughout a long-term demand forecast timescale. The exception to consider is that of longer-term climate change, now widely accepted throughout the world as a real factor on long-term weather influences. Thus, apart from climate change effects, demand forecasts based on “cold” or “mild” weather provide an envelope of possible demand levels for the period considered, rather than possible demand levels in each and every year.

### 6.4.10 Other Short-term External Influences on Demand

In addition to the effects of weather, other short-term influences on demand include the impact of commodity prices, particularly in the mining and manufacturing sectors in South Africa, where a significant part of the electricity demand is influenced by the world commodity price for products such as ferro-chrome and aluminium. In monitoring the actual demand against forecasts, it is important to identify where such influences have occurred and the extent of the impact on demand, in terms of level and duration.

## *6.5 Eskom’s Demand Forecasting*

This review of Eskom’s demand forecasting is based on the ISEP10 Report[21] plus additional information obtained from Eskom during the course of discussions and specific requests to Eskom for additional data. No attempt is made in this study to reconstruct the forecasts from the input data and this review is based primarily on the statements in the ISEP10 Report and other documentation provided by Eskom for the specific purposes of this study.

### 6.5.1 Overall Approach

Eskom’s long-term demand forecasting analysis has been developed over some ten years, as part of the ISEP process. It is a “bottom-up” process, based on over 100 individual sectors using 24 years of historic sector data. Demand is forecast for “national plus foreign” demand, meaning the aggregate of demand by customers in South Africa and exports to neighbouring countries. Although the domestic sectors are dealt with in some depth, forecasts for exports appear to be simple views of likely levels, taking into account known trends. Thus, demand forecasts with regard to exports are not based on long-term contracted sales to other countries. However, specific additions have been

[21] ISEP10 – Phase 1 – Integrated Strategic Electricity Plan - Capacity Outlook 2005 to 2024, Eskom ISEP Office, October 2005.

made to the forecast demand for exports to provide for sales to the Scorpion zinc project in Namibia and the aluminium smelters Mozal 1 & 2 in Mozambique, where it is presumed (but not confirmed) that the relevant customers have entered into long-term contractual commitments with Eskom. In situations where South Africa's demand/supply balance is tight, as it is likely to be for the next few years, it is relevant to question the extent to which Eskom should be obliged to meet export demand where it is not on a contractual basis.

Access to Eskom's demand forecast model has not been requested, as the time available for this study would not permit a detailed review of the demand forecasting process. Thus, it is assumed that the data used and processes carried out by Eskom to derive the demand forecasts are accurate and appropriate to the software employed.

It is noted that, although the demand forecast process is described in the ISEP10 Report as "bottom-up", the results are shown in terms of three main scenarios, each based on different assumptions concerning GDP growth. Ideally, it would have been useful to examine exactly how Eskom uses different GDP growth assumptions within its sector level forecasts, to ensure that the processes used are valid and appropriate but these details were not provided. In view of the differences in approach between Eskom and NIRP3, it may be appropriate to carry out a more detailed review of Eskom's demand forecasting processes in a further, separate study.

### 6.5.2 Demand Forecast Scenarios

As part of the ISEP10 process, three demand forecasts were originally developed by Eskom in early 2005, each covering the years in the plan period from 2005 to 2024 inclusive:

- High – based on average GDP growth of 5% p.a.
- Moderate – based on average GDP growth of 4% p.a.
- Low – based on average GDP growth of 3% p.a.

Much of the detail presented in the ISEP10 Report and the sensitivity analyses carried out by Eskom appear to be based on the "moderate" growth forecasts, implying that Eskom attaches the greatest credibility to the moderate scenario.

In September 2005, following the Government's announcement of plans for the South African economy to grow by 6% per annum by 2010, Eskom produced a further demand forecast scenario:

- Extra High – based on an average GDP growth of 6% p.a.

This demand forecast appears to be the basis for Eskom's generation capacity expansion plan included within the Eskom Corporate Plan (March 2006), rather than any of the demand forecast scenarios included in ISEP10. No details have been provided to show how the "extra high" demand forecast has been derived, so it is not possible to review the process. However, it appears that there is a fairly consistent relationship between the assumed level of annual GDP growth and the annual growth in electricity sales (GWh) and peak demand (MW), as shown by the following figures presented by Eskom on 11 May 2006:

**Table 2 – Eskom Demand Growth Assumptions**

| Forecast | GDP % average p.a. growth | MW peak demand % average p.a. growth |
|---|---|---|
| High | 5 | 3.2 |
| Moderate | 4 | 2.3 |
| Low | 3 | 1.4 |
| Extra High | 6 | 4.4 |

The DPE is known to have a keen interest in the linkage between GDP growth and electricity demand growth. There is ample international evidence to demonstrate that there is a strong correlation, in most countries between the two. However, the linkages are complex and generally non-linear, for many reasons, including:

- There may be a lag between demand growth and economic growth, so that it is difficult to track the changes in the two variables over a short period. This is particularly difficult in periods exhibiting volatile changes in either variable.
- Whilst electricity demand data is reliable and accurate (based on metering), GDP measurement is known to suffer from significant inaccuracies.
- Electricity demand in certain sectors is driven not by domestic economic growth but by international commodity prices.
- In some sectors, such as residential, demand growth may be partly driven by economic growth but in a complex manner. Some growth, for example electrification, is not driven by economic growth but, to some extent, may depend on growth of funding. Some load may actually decrease as a result of high economic growth – for example, high levels of household expenditure may be associated with renewal of older, less efficient electrical appliances for newer ones using less energy.
- It is difficult to determine to what extent GDP growth (positive or negative) drives electricity demand or whether GDP growth itself may be partly dependent on an adequate supply of electricity to help fuel growth in the economy. The most likely explanation is that the economy drives electricity demand but that, if the supply of electricity is not sufficient to meet demand growth, economic growth could be held back.

It has become apparent, during discussions with Eskom, that there is reluctance on behalf of Eskom to accept that the target GDP growth under the Government's Accelerated and Shared Growth Initiative (ASGISA) has much chance of being met. This is an inappropriate attitude to adopt, particularly for a state-owned enterprise. Whatever the level of GDP growth achieved, if the generation capacity has not been provided to enable the potential demand to be met, there is a possibility that Eskom could be accused of not providing an adequate level of generation capacity to fuel GDP growth.

### 6.5.3 Sector Demand Forecasts

As discussed in the section above (overall approach), it is not known exactly how the different assumptions of GDP growth drive the sector forecasts in Eskom's "bottom-up" approach. However, it is clear from the above table that GDP is a highly significant driver to many sectors. This is to be expected, although the manner in which GDP drives demand would vary between sectors. For example, in the commercial sector, GDP growth will lead to an increase in the output of the service sector of the economy, which in turn would lead to increases in the number of shops, offices, schools, hospitals, etc. although newer premises would be likely to be more energy efficient than older premises. In the residential sector, there will be differences in the manner in which GDP growth drives demand in rural areas and urban areas. In manufacturing and mining, the relationship between GDP growth and demand will be via the impact of GDP growth on each individual industry. All that can be observed from the results presented in ISEP10 is the overall relationship between GDP growth and aggregate electricity demand.

The ISEP10 Report confirms that the demand forecasts include particular expectations regarding load increases due to large industrial projects, which explains the above average growth in the early years of the planning period. It could be argued that a “top-down” approach will automatically account for such increases but this would only be the case on average over a relatively long period. In view of the short timescale for these projects to develop, it is prudent to take particular cognisance of such increases, in order to avoid a shortfall in capacity in these years.

It is the view of the authors of this Report that Eskom’s approach, in using sector electricity demand data, is the right approach. However, in order to provide a better insight into the 45% of total electricity sold by the Municipalities, it is suggested that an improvement to this approach would be to develop a full sector model of South African electricity demand, across all distributors. This would require co-ordination of data by an entity such as NERSA.

### 6.5.4 Demand Data

A point of comment on the ISEP10 Report, although apparently minor, is actually quite significant and relates to the presentation of demand forecast data. The demand forecasts results on page 25 of the ISEP10 Report show only the moderate forecast results. Eskom has provided a separate table of demand forecasts results, as part of a series of data in an excel spreadsheet (Appendix B to the ISEP10 Report). However, this Appendix and the table on page 25 do not show the actual data shown for 2004 – the base year for derivation of the annual growth rates. Thus, there is no fixed point of reference with which to check the annual growth rates.

### 6.5.5 Load Shape and Peak Demand

For reasons explained in the general discussion on load forecasting above, it is important to ensure that the appropriate load shape is used to model the demand for each sector. Since Eskom uses a “bottom-up” sector approach, this would be inherent in its forecasting methodology. Thus, the detailed load shapes will be used as inputs to generation expansion optimisation. It is noted that the ISEP10 demand forecasts show the annual system load factor at a significantly higher level compared to the previous demand forecast, ISEP9A. The ISEP10 Report states that the system load factor has been steadily increasing since 1995 but, in fact, the graph on page 26 of the ISEP10 Report shows that actual changes in load factor from year to year are quite volatile. It is probable that some of this volatility may be due to weather impacts and supports the need for a weather corrected actual demand figure to be calculated, as proposed in the section on weather effects. Although the system load factor has been increasing, Eskom’s demand forecasts show it reducing gradually in future, after 2006. This may be due to the relatively higher growth in those sectors with a more “peaky” demand than those with a high load factor. Unfortunately, the ISEP10 Report does not show sector demand forecasts, even a high level of disaggregation such as the main sector split used in Eskom's Annual Report, which would have been useful.

### 6.5.6 Distribution and Transmission Losses

The ISEP10 Report includes a graph of system losses (believed to be a combination of transmission losses and those distribution losses within Eskom's distribution networks), showing losses increasing significantly from around 1990. This is attributed to the electrification programme, where the extension of low voltage networks in rural areas incurs relatively high distribution losses. However, given the relatively small proportion of sales to the electrification sector, it is hard to understand how electrification can be the main effect and it is likely that other factors, probably including theft of electricity, is impacting on system losses. The ISEP10 Report states that the actual level of losses (10.1%) in 2004 is used as a starting point and it is understood that losses are assumed to increase to 12.1% by 2025. It is presumed that the increase in distribution losses is accounted for by the change in mix of sales towards a greater proportion of sales at lower voltages. It is also apparent that the same percentage figure for losses is used across all three scenarios in ISEP10, which is not consistent with a change in mix of sales between the scenarios, which is most likely. A sector breakdown of the demand forecasts might enable this to be confirmed.

### 6.5.7 Demand-side Management (DSM) Initiatives and Interruptible Loads

The ISEP10 forecast assumes a more conservative penetration of DSM programmes than previous demand forecasts. This is prudent, given the lack of clear evidence for actual achievement of demand reductions from such programmes. However, there may be some double counting involved in this process, since the sector forecasts should already, to some extent, take account of demand reductions from energy efficiency and new technologies.

With regard to interruptible load contracts, these contracts, totalling over 2000MW of demand reduction, have a very significant impact in helping to reduce peak demand. As such, it is not clear why more effort is not being expended in persuading these customers to renew their contracts when they expire. The value of interruptible load can be compared directly with the alternative of additional peak generation, at the marginal plant cost. The value of maintaining these contracts is inferred in the ISEP10 Report but it is unclear how this is reflected in Eskom's trading plans.

### 6.5.8 Weather Impact on Demand

Eskom does not carry out weather correction for actual demand levels. Instead, weather sensitivity is provided within the overall sensitivity ranges around the central demand forecasts. However, Eskom believes that cold weather can add between 700MW and 1000MW to the peak demand. At that level, the impact of weather is significant and equivalent to a year's demand growth. It is not sufficient, therefore, to rely on what are essentially guesstimates of the weather impact for planning purposes.

### 6.5.9 Sensitivity Testing and Risk Analysis

Eskom has produced (as Appendix C to the ISEP10 Report) a series of sensitivity variations on demand levels for the "moderate" forecast for each year of the plan period (2005-2024), in conjunction with sensitivities to generation plant availability and capacity.

The sensitivities used for the demand forecast in ISEP10 are:

- Moderate growth, cold weather, upper bound.
- Moderate growth, hot weather, lower bound.

Eskom explained that the sensitivities include variations due to weather effects and additional demand uncertainties. However, Eskom did not clarify the extent of the weather impact within the two scenarios, so it is not known to what extent other factors have been included in the upper and lower bounds. From the data shown in the ISEP10 Report, the “cold weather, upper bound” sensitivity is around 5% higher than the central “moderate” forecast, each year, for peak demand and around 2% higher for annual sales (GWh). The “hot weather, lower bound” sensitivity is around 5% lower than the central “moderate” forecast, each year, for peak demand and around 2% lower for annual sales (GWh).

The use of sensitivity tests to show upper and lower bounds for a central demand forecast scenario is a useful method to illustrate the range of uncertainty associated with a particular forecast. However, since Eskom does not explain the derivation of these sensitivity bounds in the ISEP10 Report, the ranges are less than meaningful. If a statement could be included to illustrate the degree of confidence associated with these ranges, they would be more useful.

The only other data provided by Eskom in relation to sensitivity tests is the detailed data spreadsheets for a number of permutations of central, lower and upper bound (for the moderate scenario) together with variations in target and lower plant availability and plant capacity. An examination of these spreadsheets indicates that each of the 12 separate plans included has exactly the same demand level for each year, so it is unclear how and what has been done with regard to demand forecast sensitivity testing.

### 6.5.10 Accuracy of Previous Eskom Demand Forecasts

A comparison of previous demand forecasts with actual demand (important for reasons explained in the section above on general demand forecasting issues) is not produced as part of the ISEP reporting process. Although Eskom has provided a graphical depiction of such a comparison (within the “ISEP Forecasts” presentation of 11 May 2006) this does not provide a quantitative comparison. A relevant comparison would be to show the actual annual GWh and MW peak demand for each of the past few years, against the demand forecast for those years made some 5-10 years previously. Comparing the demand forecast for only 1-2 years prior to the actual year is inadequate, since the relevant time horizon for planning purposes is much longer than this.

## *6.6 NIRP3 Demand Forecasts*

The following comments on the NIRP3 demand forecasts is based on a review of the Stage 2 Report (Draft), issued to the Advisory Review Committee (ARC), on 1 March 2006.

### 6.6.1 Overall Approach

The NIRP3 approach for demand forecasting differs significantly from the approach adopted by Eskom. The NIRP3 Report states that a “top-down” approach is adopted but also employs a “bottom-up” method to assess the impact on electricity demand of changes in energy intensity and other impacts.

There is a clear focus, in the NIRP3 approach, on the relationship between GDP growth and electricity demand growth, an approach developed initially for NIRP2 in 2003/04. NIRP3 introduces additional variables, in particular population growth, to help determine the demand forecast and examines the relationship for each province of South Africa, in addition to the national level. However, it is not clear from the NIRP3 Report how provincial level demand forecasts are to be used in the electricity planning process.

A spreadsheet-based model is used in NIRP3 to test the relationship between historic electricity demand, population and GDP growth, by regression analysis. The NIRP3 Report states that GDP growth is the key determining factor for electricity demand. Whilst this result is intuitively correct, regression analysis is known to be unsuitable for testing relationships between variables that are multiply correlated, since it is difficult to determine the causal relationships.

A major drawback of this approach, recognised in the NIRP3 Report, is that the underlying assumptions that coefficients of future energy growth remain constant over time, is flawed. However, as explained in the NIRP3 Report, this drawback is compensated by using a “bottom-up” approach to assess the impact of changes in energy intensity and other factors. Unfortunately, the NIRP3 Report does not clarify how this additional bottom up process has been used to determine the demand forecasts.

### 6.6.2 Demand Forecast Scenarios

Demand forecasts for NIRP3 were carried out later than Eskom’s ISEP10, after the announcement of the Government’s ASGISA economic growth target of 6% by 2010. However, the demand forecast scenarios adopted for NIRP3 do not explicitly include a scenario based on ASGISA. Three scenarios have been used (as in ISEP10) but with somewhat wider range of GDP growth. The table below compares the GDP growth rates assumed under NIRP3 with those assumed under ISEP10:

**Table 3 – NIRP3 and ISEP10 GDP Growth Assumptions**

| **NIRP3** | | **ISEP10** | |
|---|---|---|---|
| Scenario | GDP growth % p.a. | Scenario | GDP growth % p.a. |
| High | 5.9 | High | 5 |
| Medium | 4.7 | Moderate | 4 |
| Low | 2.8 | Low | 3 |

Thus, the assumed levels of GDP growth for the NIRP3 scenarios are relatively close to those used in ISEP10, although the “high” and “medium” scenarios are almost a percentage point higher than ISEP10, whereas the “low” scenario of NIRP3 is slightly less than ISEP10. The NIRP3 Report shows the assumed level of GDP growth for each scenario for each year, from a starting point of around 4.4% for 2005. Recent figures indicate that the GDP growth in 2005 was in fact close to 5%. The “high” scenario assumes that GDP growth will progress steadily to 6% by 2010, so is actually in line with the ASGISA target. The “medium” scenario suggests a strange “wobble” in 2006/2007, followed by a slow increase to just under 5% by the end of the plan period (2025). The “low” scenario indicates a sharp decline in GDP growth to around 2.5% by 2012, remaining at this level thereafter.

The NIRP3 Report does not make a strong case for adopting any one of the three scenarios but appears to favour the "medium" scenario as the most credible.

For all three scenarios, a breakdown is provided of the GDP growth rates for each of the nine provinces, in addition to the national figures, for the plan period.

### 6.6.3 Sector Demand Forecasts

A key difference between the ISEP10 and NIRP3 approaches to demand forecasting is that NIRP3 examines the electricity intensity for each of the major sectors. However, the source of the electricity demand by sector is not clear (stated in the NIRP3 Report as being provided by Global Insight) and there is a lack of clarity as to how the assumptions on changes in electricity intensity over the plan period have been made.

Population growth rates are derived for each of the nine provinces in addition to the national figures, also provided by Global Insight. The assumptions indicate that the national population growth rate will decline initially to 0.4% and increase slightly after 2015. On a provincial basis, however, some provinces show an increasing rate of population growth (Limpopo and Eastern Cape) whereas Gauteng and some other provinces show a marked decline to around zero growth.

### 6.6.4 Demand Data

In NIRP3, Total Electricity Requirement (TER) is defined as the sum of:

- Electricity generated by Eskom (net of own use);
- Electricity generated by Municipalities;
- Electricity generated by industrial customers and used on-site;
- Transmission and distribution losses; and
- Net imports (imports – exports).

Including electricity generated by industrial customers, which is used internally on their own sites, is apparently necessary in order to relate total electricity demand with total output (i.e. contribution to GDP) from those industries. However, the figure is based on estimates and, as becomes clear later in the NIRP3 Report (page 47), it is assumed that the contribution of "other" generation remains at a constant proportion of overall generation. Thus, the rationale for including other generation is unclear.

The figure for TER shown in the NIRP3 report (page 56) for the year 2005 (presumed actual, since the same figure is shown for all three scenarios) is 221,715 GWh. It is difficult to reconcile this figure with any published data. The figure for "national + foreign" demand used in ISEP10 for the year 2005 (moderate scenario) is 238,542 GWh. Given that the NIRP3 figure includes other generation (whereas ISEP10 does not); it is difficult to understand why the NIRP3 figure should be substantially less than that used in ISEP10. However, it is noted that the assumption on system losses used in NIRP3 is very low (see section below on losses).

### 6.6.5 Load Shape and Peak Demand

The NIRP3 Report shows the results of the demand forecast process in terms of GWh per year and peak demand MW each year, for all three scenarios. However, it is unclear how these figures have been derived, apart from the brief explanation of the approach used.

With regard to the peak demand figures (MW), it seems that a constant load factor of 75% has been used for all of the years from 2010 onwards, compared with 76.4% for 2005, to allow for a “peakier” load profile due to the decline of demand in the mining sector. These results contrast with ISEP10, where the load factor changes in line with the mix of sales to each sector over the plan period and, as would be expected, differs between the three scenarios.

It is apparent that a very simplistic approach has been adopted in NIRP3 towards load shape, which is crucial to deriving an optimum system generation expansion plan and will also impact on transmission and distribution expansion requirements.

### 6.6.6 Distribution and Transmission Losses

An analysis in the NIRP3 Report (page 23) shows data for the last 6 years (2000 – 2005 inclusive) for Eskom generation; Eskom use; Net imports; Other generation; Losses and Total generation available. The NIRP3 Report states that losses are calculated as the difference between total generation available and the end-use consumption (which is not shown in the table of data). It is not clear where the data on end-use is derived (and since it is not shown it cannot be validated) but the figures that result for losses are very low and inconsistent (6.2% in 2000 and between 7.6% and 7.9% for the other years). Eskom data shows that Eskom’s transmission and distribution losses are currently around 7.9%, to which has to be added the distribution losses within Municipality distribution networks, to arrive at the ISEP10 figure for total losses of 10.1%.

The assumption in NIRP3 with regard to losses is that losses will remain at a constant percentage (7.9%) over the plan period for all three scenarios, which is inconsistent with a change in the mix of sales over the plan period and between scenarios.

The NIRP3 Report includes a short description of Loss Load Factor (LLF) and peak power losses, which is technically correct but it is not clear how LLF or peak power losses are used in the demand forecasting process. It would be helpful to show how the calculations of LLF and peak power losses are used in the demand forecasts.

There appears to something wrong with the calculation of losses in NIRP3. However, it is unclear how this affects the demand forecasts, as the NIRP3 Report does not clarify how the GWh demand figures have been produced.

### 6.6.7 Demand-side Management (DSM) Initiatives and Interruptible Loads

No demand-side initiatives are discussed in the NIRP3 Report. Presumably, some impact of efficiency measures will be taken account of in the modelling of the electricity intensity for each sector. It is also presumed that the contribution of DSM and Interruptible Load customers will be included as supply-side alternatives in future stages of the NIRP3 analysis.

### 6.6.8 Weather Impact on Demand

There is no discussion of weather impact on demand in the NIRP3 Report. That is only reasonable if weather is not considered as an important risk factor, which seems to be a somewhat dangerous assumption for the situation in South Africa.

#### 6.6.9 Sensitivity Testing and Risk Analysis

Apart from the three scenarios, the NIRP3 Report does not include the results of any sensitivity test on the input assumptions. It is not clear whether or not such sensitivity tests are to form part of a later stage of the NIRP3 work or not.

#### 6.6.10 Accuracy of Previous NIRP Demand Forecasts

Since NIRP3 is a new approach, it is not possible to test the accuracy of its forecasts against actual historic demand data.

### *6.7 Overall Assessment of Demand Forecasts in ISEP10 and NIRP3*

There are merits and disadvantages with both the ISEP10 and NIRP3 approaches to demand forecasting. Also, there is lack of clarity, in both the respective reports, on how the results have been obtained. The relationship between GDP and electricity demand is covered in a more explicit manner in NIRP3 than in ISEP10 but the NIRP3 Report still lacks clarity as to exactly how this relationship is used in producing the demand forecast results. Generally, the sector approach to demand forecasting is likely to produce a more accurate assessment of overall demand and, for this reason, the ISEP10 approach is favoured. Although the NIRP3 Report states that a sector approach has also been used to assess changes in electricity intensity by sector, there is again a lack of detail as to how this is carried out.

There are inconsistencies between ISEP10 and NIRP3 with regard to the basic historic data on generation, end-use sales and losses, which should not really be difficult to resolve and it is suggested that both process would gain from co-ordination to remove these inconsistencies. It is suggested that NERSA would be best placed to facilitate such co-ordination to ensure that everyone agrees on the basic historic data.

The above review of ISEP10 demand forecasts makes a number of specific recommendations to improve the process, since it is believed that discussions between DPE and Eskom on these recommendations would be useful. No specific recommendations are made with regard to NIRP3, although the above discussion makes a number of comments about the NIRP3 process and the results. It may be appropriate for these comments to be raised through the Advisory Review Committee (ARC).

### *6.8 Current Level of Security of Supply*

As has been the case recently in both Europe and North America, the loss of electricity supplies in South Africa, (and in particular the Western Cape during the first half of 2006), has brought the issue of security of electricity supply in South Africa sharply into focus. Secure electricity supplies are required to underpin national economic development and any event that brings the current level of security into question is inevitably of national concern.

The problems experienced with the availability of the Koeberg power plant have demonstrated very clearly that, with the generation and transmission infrastructure that is currently available in South Africa, the loss of a single 900MW generating unit at the Koeberg station for any extended period during the winter months results in Eskom being unable to meet customer demand in the Western Cape. This illustrates clearly that the security of electricity supply in South Africa is currently at risk from a single (albeit low probability) event.

The loss of supply incidents in the Western Cape have demonstrated three factors which impact directly upon security of supply:

- The low generation reserve margin that is available nationally;
- The limitations of the transmission system to deliver power that is generated in the north east of the country to the Cape region; and
- The requirement for high availability of power plant.

These three aspects are discussed below.

## 6.9 The Reserve Margin

Over the past 10 years the reserve margin has fallen very significantly as a result of growth in electricity demand of around 3% per annum (which equates to approximately 1,000MW of additional peak demand each year) and the very limited amount of new generating plant that has been commissioned.

Currently, there is some confusion about the figures quoted for reserve margin as Eskom use a number of different definitions. It is not always clear whether the reserve margin includes or excludes certain elements of Demand Side Management (DSM) and Interruptible Load (IL) contracts. The reserve margin is a measure of system reliability and thus any adjustment that artificially increases this margin could result in a false sense of security. The only demand side options that are of benefit to the System Operator in the event of a system incident are those demand measures that can be called upon immediately, such as interruptible loads[22]. It is more appropriate to adjust the demand forecast to take account of other DSM measures rather than include them as pseudo generation. If the various DSM measures are excluded, the reserve margin in 2005 was under 10% and is forecast to fall to 8% in 2006 and remain under 10% until 2012. Based upon figures provided in Eskom's ISEP10 robust plan, a forecast of reserve margin to 2023 is shown in Figure 1.

[22] While interruptible loads are of real benefit to the System Operator, they are less flexible than the ability to call on peaking generation, which can be run for as many hours as is required in an emergency.

**Figure 1 – Reserve Margin Projections**

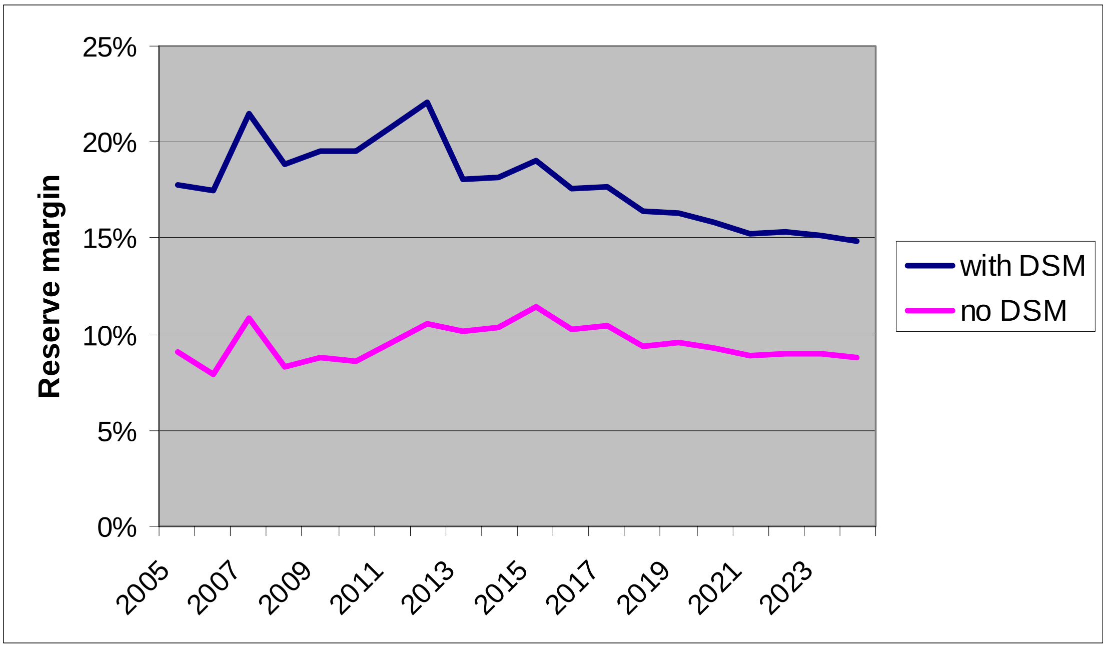


Figure 1 has been derived from an analysis of the robust plan (Plan 12) in Annex C of the ISEP10 report.

A number of points can be noted from Figure 1:

- Without a contribution from the demand side, the reserve margin varies between 8% and 11% over the planning horizon;
- The inclusion of various new DSM is forecast to increase the reserve margin from 17% in 2006 to 21% in 2007; and
- The reserve margin including DSM is projected to be in the range 18% to 21% until 2012 when it starts declining again to 15% in 2024.

Eskom considers a number of demand side measures in its planning process including:

- Demand market participation (DMP) of 600MW which is forecast to rise to 1,000MW;
- Customers on interruptible load (IL) contracts of 2,145MW; and
- Energy efficiency measures.

If all the above demand side measures are taken into consideration the forecast reserve margin rises to 20.3% in 2006. However, it is noted that there are restrictions on the number of times customers on interruptible load contracts can be interrupted and thus such contracts are not equivalent to supply side options (which can be called upon as often as is required) for the provision of reserve.

Given that the relatively tight supply demand balance is likely to persist for the next few years, the South African power system will remain potentially vulnerable to any major power station outage either as a result of technical failure or fuel supply constraints.

Recent Eskom experience is that the availability of existing power plant is falling as forced outage rates have increased. In recent years, planned maintenance at power plants has been increasingly “rolled over” (i.e. postponed). This is due in part to a reduced opportunity to take plant out as the reserve margin has decreased. In addition, Eskom bonus arrangements provide strong incentives for plant managers to reduce the duration of planned outages. While reduced outage durations is a desirable objective, care must be taken that such incentives do not result in reductions in planned maintenance resulting in higher forced outages. Careful monitoring of power plant performance is thus required to ensure that incentive arrangements are not perverse.

It is also noted that recently there have been a number of closures of non-Eskom generation, for which Eskom received no advanced notice of the closure. The impact of such closures is an unexpected reduction in the available plant margin.

## *6.10 Transmission Constraints*

Many regions of South Africa have demand levels in excess of the generation capacity connected within the region. Thus, in order to meet demand, it is necessary to transmit significant quantities of power from those regions with generation capacity surplus to those with a generation deficit. However, the amount of power that can be transmitted from one region to another depends on the installed transmission capacity and the technical limits imposed on the transmission lines. The reliability associated with such transmission circuits depends upon the design criteria adopted for transmission planning purposes.

A particular case is the Western Cape region. There are both thermal and stability limits that impact upon the transmission of power to the Western Cape[23]. Transmission improvements are planned in the next six to eighteen months, which will increase the transfer capability, by 200MW to 300MW by upgrading the series capacitors. However, whilst these enhancements will improve system security, the costs are justified not by increased security but by the reduction in transmission losses.

A 765kV overlay system is scheduled for the end of 2009, which will increase the transfer capability, by a further 650MW to 700MW, which should increase the security of supply to the Western Cape significantly. It has not been possible to establish a business case for commissioning this 765kV reinforcement prior to 2009 because the load under threat in the Cape region was not considered to be large enough to justify the expenditure. The current policy on transmission reinforcement, as defined in the Grid Code, thus results in some loads not being secured to the N-1 standard. Under the current arrangements, reinforcement will only take place when the size of the load at risk multiplied by the CoUE is sufficiently large to justify the associated expenditure. Thus,

[23] The thermal limit is associated with the series capacitors that are in the process of being upgraded. The voltage stability limit results from transmitting power over a distance of 1,500km with very limited generation en route (the Orange River hydro schemes). A healthy system (i.e. with all transmission circuits in service) is capable of transmitting 3,500MW but with one line out this transfer limit reduces to 2,900MW. The peak demand on the Southern and Western Grids is currently close to 5,000MW.

prior to reinforcement being justified, an event that results in an outage of a transmission circuit at times of high demand is likely to cause customer interruptions.

There are significant losses associated with transmitting power to the Cape. With both units at Koeberg in service transmission losses are 300MW, with one unit at Koeberg out of service these losses rise by 200MW while with two units at Koeberg out of service the losses rise by a further 300MW. The value that Eskom assigns to transmission losses has increased significantly, associated with the tightening capacity situation, which means that developing a business case for transmission reinforcement to the Cape has been much easier.

## *6.11 Plant Availability*

A critical influence on the level of security of supply of a power system is the availability of generating units and transmission lines which is contingent upon:

- Planned outages; and
- Forced outages.

Both types of outage have a significant impact upon system reliability but because of the random nature of forced outages these tend to have a disproportionately high impact. A number of factors influence forced outages including the age of plant, the operating regime of plant, weather conditions, protection settings, and the thoroughness of the planned maintenance that has been undertaken.

Any deterioration in generation or transmission system availability needs to be reviewed critically for its impact upon system reliability and remedial action taken where this is appropriate. This is particularly true when the reserve margin is low. In the case of loss of supply in the Western Cape, the initial loss of a unit at Koeberg was seriously compounded by forced outages on transmission circuits.

## *6.12 Cost of Unserved Energy*

Eskom is of the view that the reliability cost / reliability worth method is the only one acceptable for consistency in planning between Generation, Transmission and Distribution[24]. This method is based on a trade-off between the cost of reliability and the cost of unreliability as illustrated in Figure 2.

[24] See Eskom's Briefing note on Reserve Margin.

**Figure 2 – Eskom Assessment of Optimum Reliability[25]**

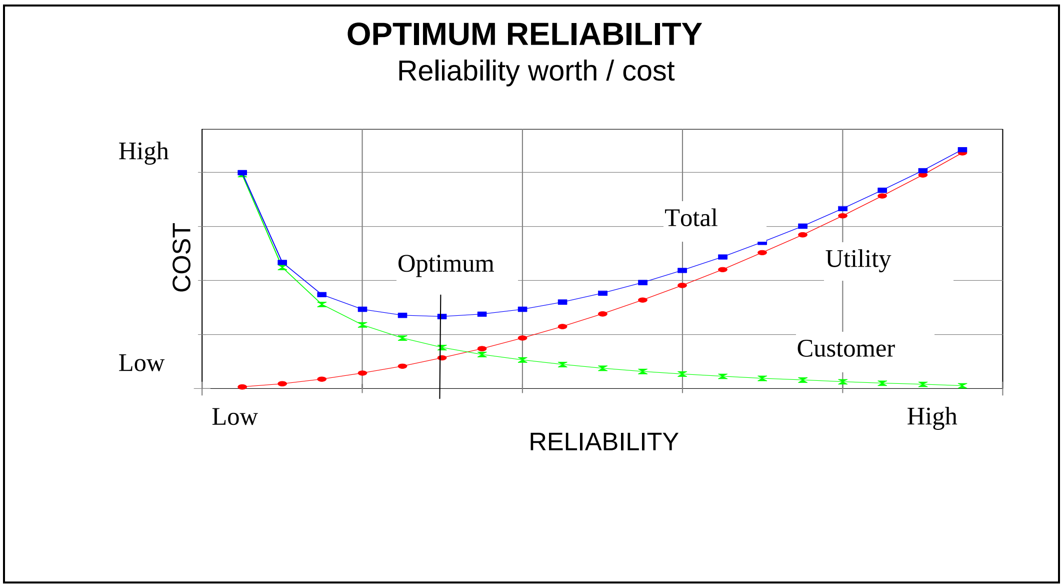


Figure 2 plots the costs of providing enhanced system reliability by the provision of additional generation capability by Eskom (the red line) against the cost to its customers associated with any unserved energy. Thus for a system with high reliability the utility costs are high (due to the need to build more power plant) whereas the costs associated with customer interruptions are low (due to a very low level of interruptions) and vice versa. The theoretical optimum level of power system reliability can then determined by plotting the sum of utility and customer costs to establish where this total cost would be minimised.

The above approach is predicated upon the use of the "correct" cost of interruptions to customers and the outcome of the associated planning process is thus very dependant upon how the cost to customers is evaluated. The cost of unserved energy (CoUE) is a measure of the value that customers place upon security of supply and is estimated by attempting to quantify the cost of energy not supplied to customers as a result of energy shortfalls. Intrinsically the CoUE is very difficult to estimate accurately.

Customer surveys in the USA have indicated that CoUE is in the range US$2,000 to US$50,000/MWh depending upon the frequency and duration of outages and their consequences to particular customers. In the ISEP10 plan Eskom has used a figure of R20,470/MWh while NERSA's consultants have proposed using R18,228/MWh.

Press reports of losses to customers of R6 billion associated with outages in the Cape suggest that the ISEP and NIRP figures may seriously underestimate the CoUE. If the figures in the press are correct the CoUE in South Africa could be around R350,000/MWh, which is some 17 times greater than the figure used by Eskom. Using a CoUE energy figure of this magnitude would tend to increase the "optimal" reserve margin by some 4% to 5%. A number of customers in the Cape have chosen to

[25] Source: Eskom's Briefing note on Reserve Margin.

purchase and operate their own diesel generators, which implies that such customers place a high value on their security of supply.

Eskom uses CoUE in planning its generation and transmission systems. Thus, if the current value of CoUE used by Eskom in its planning process underestimates its true value, system reliability will almost certainly be lower than that desired by customers. This in turn implies that customers would be prepared to pay a premium in their electricity prices for an improvement in their security of supply.

It is important to note that Eskom has not adopted any explicit security standard in its planning process. Rather, security of supply is deemed to be “optimal” where the system is designed with a security in line with the figure of CoUE adopted.

## 6.13 Generation Expansion Plans

The Integrated Strategic Electricity Plan (ISEP) is Eskom’s long term generation capacity planning process. The most recently finalised plan is ISEP10 for which an internal Eskom report was produced in October 2005. In the course of the ISEP process, Eskom produces a number of capacity expansion plans. The most robust plan to be developed within the ISEP10 process was Plan 12, which is shown in Figure 3.

**Figure 3 – Eskom Robust Plan (ISEP10)**

| | Mothballed | | | Coal-Fired | | | | | Gas | | | Pumped Storage | | | DSM | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| YR | Cam (PF) | Gr'vlei (PF) | Kom (PF) | PF (1) | PF (2) | PF (3) | PF (4) | PF (5) | OCGT Atlantis | OCGT Mossel Bay | OCGT IPP | PS (A) | PS (B) | PS (C) | CEE IMEE IMLM REE RREE RLM | DMP1 & DMP2 | Reserve Margin on primary assumptions |
| 2005 | 380 | | | | | | | | | | | | | | 214 | 310 | 18% |
| 2006 | 380 | | | | | | | | | | | | | | 169 | 155 | 17% |
| 2007 | 570 | 188 | | | | | | | 616 | 452 | | | | | 169 | 125 | 21% |
| 2008 | 190 | 376 | 101 | | | | | | | | | | | | 169 | | 19% |
| 2009 | | 564 | 202 | | | | | | | | 904 | | | | 169 | | 20% |
| 2010 | | | 303 | 636 | | | | | | | | | | | 169 | | 20% |
| 2011 | | | 303 | 636 | 636 | | | | | | | | | | 169 | | 21% |
| 2012 | | | | 636 | 636 | | | | | | | | | | 98 | | 22% |
| 2013 | | | | | | | | | | | | 999 | | | | | 18% |
| 2014 | | | | | 636 | | | | | | | 333 | | | | | 18% |
| 2015 | | | | | 636 | | | | | | | | 1002 | | | | 19% |
| 2016 | | | | | 636 | | | | | | | | | | | | 18% |
| 2017 | | | | | 636 | 636 | | | | | | | | | | | 18% |
| 2018 | | | | | | 636 | | | | | | | | | | | 16% |
| 2019 | | | | | | 636 | 636 | | | | | | | | | | 16% |
| 2020 | | | | | | 636 | 636 | 636 | | | | | | | | | 16% |
| 2021 | | | | | | 636 | 636 | 636 | | | | | | | | | 15% |
| 2022 | | | | | | 636 | 636 | | | | | | | | | | 15% |
| 2023 | | | | | | | 636 | 636 | | | | | | | | | 15% |
| 2024 | | | | | | | 636 | 636 | | | | | | 1002 | | | 15% |
| TOTAL | 1520 | 1128 | 909 | 1908 | 3816 | 3816 | 3816 | 2544 | 616 | 452 | 904 | 1332 | 1002 | 1002 | 1325 | 590 | |

Eskom is currently in the process of returning to service three previously mothballed coal plants at Camden, Grootvlei and Komati over the period to 2011. Eskom is also building two OCGT plants at Atlantis (4 by 150MW) and Mossel Bay (3 by 150MW), which should add 1,050MW of new gas turbine capacity by the first quarter of 2007. DME has issued a request for proposals for 1,000MW of OCGT plant to be developed by an IPP and, for ISEP10, Eskom has assumed that this will be in service by 2009.

Over the five-year period 2005 to 2010, Eskom forecasts that the peak demand (without taking into account DSM) will rise by 5,500MW (averaging 1,100MW per annum). The capacity additions in Eskom’s Plan 12, over the same period, total 5,800MW. Thus forecast generation capacity additions in this robust plan broadly match forecast load growth over the period. The forecast increase in the reserve margin over the next 5 years is as a result of a projected increase of 1,100MW of demand side measures rather than from new capacity being added faster than the demand is growing.

It is therefore far from certain that implementation of the ISEP10 plan will deliver a significant improvement in security of supply from the current level. In addition, if the return to service of mothballed plant, the commissioning of any of the new gas turbines run behind schedule or the forecast level of DSM fails to materialise, the capacity situation in the short will become tighter. In this context it is noted that:

- There have been technical problems in returning the Camden units to service which has resulted in delays; and
- The IPP tender process has run much slower than would have been reasonably expected (in part as a result of protracted contract negotiations on the off-take arrangements and sharing of risks between Eskom and the Developer).

It is also noted that because the Eskom system is becoming both capacity and energy constrained, the power system is likely to be under stress at any time of the year rather than just at times of winter peak. This is because the large thermal units need to be taken out for service for planned maintenance and, as the supply/demand balance situation becomes tighter, scheduling such maintenance becomes ever more challenging.

For the period beyond 2010, Eskom is seeking for approval to proceed with the arrangements to procure generating units for the construction of a coal-fired power station consisting of 3 x 636 MW generating units. A further four large coal plants are also included in the robust plan to follow this expansion with a total of twenty five 636MW new coal units planned to be commissioned over the period 2010 to 2024. Eskom also plans to construct three pumped storage stations having a total capacity of 3,326MW with the first unit currently planned for commissioning in 2013.

Discussions have taken place regarding the option of building nuclear power plants (involving both conventional PWR technology and the PBMR) at the Koeberg site. Eskom views nuclear plants in the Cape as a possible alternative to additional coal fired plant.

Consideration is also being given to a combined cycle power plant at Coega to run either as a base load or mid merit station. This option would have the benefit of providing further generation capacity in the Cape region but is contingent upon Liquefied Natural Gas (LNG) being available at a competitive price and the associated gas infrastructure being in place.

The decision as to where new power stations are located is important from a regional security of supply perspective. Locating a new power plant in the Cape region would intrinsically mean that supplies to the Cape were more reliable than building a new coal fired plant in the north east unless the transmission capability to the Cape is significantly enhanced.

The ISEP process is concerned with determining the most economic generation expansion plan and it does not explicitly consider regional security of supply issues. Eskom's plans for the transmission system reinforcement required to deliver energy to the seven transmission regions is discussed below.

## 6.14 The Cost of Improving Security of Supply

Security of supply can be enhanced by installing additional generation capacity and thus increasing the generation reserve margin. The technology option that currently has both the lowest capital cost and the shortest lead time to commission is the open cycle gas turbine (OCGT). Building an OCGT is not necessarily the least cost generation expansion option as the fuel cost for an OCGT is relatively high and its thermal efficiency relatively low. OCGTs therefore tend only to be built for peaking duty or for use during emergencies.

For example, installing an additional 3,000MW of OCGT would increase the reserve margin by around 8% and would have a lead time of around 2 years. It would thus be possible to significantly enhance security of supply in the short term.

The annualised capital cost of 3,000MW of OCGT would be R750million/annum, which would add approximately 3R/MWh (around 3%) to the wholesale cost of generation. There would, in addition, be the fuel cost associated with running the GTs, which would depend on the amount of peaking duty required. The amount of additional security that is appropriate is dependant upon how much customers would be prepared to pay for such enhanced reliability. Anecdotal evidence from the Cape suggests that there would be a willingness by most customers to pay a "reliability" premium of this sort of magnitude.

## 6.15 Transmission Reinforcement

The Eskom transmission system operating and planning criteria are specified in the South African Grid Code[26]. The transmission planning standards specify an N-1 criterion for loads and N-2 criteria for base load generating plant subject to 83% of their rated outputs[27].

However, in order for any transmission reinforcement to be approved, there is a requirement for Eskom to make a business case before such reinforcement can proceed. To make such a business case a new line must satisfy one of the following two economic criteria:

- The net present value (NPV) of the reduced cost of losses and operation and maintenance is greater than the cost of the line; or
- The expected NPV of cost of interruptions to customers associated with unreliability must exceed the cost of the line. Such costs are evaluated using the cost of unserved energy.

Because of these economic constraints to system reinforcement, not all of Eskom's transmission system meets the N-1 criterion. Thus, customer's supplies can be at risk

[26] See South African Grid Code - The Network Code and The System Operation Code.
[27] The figure of 83% is based on 5 out of 6 units for Eskom's large stations and consideration is being given to changing the 83% for other power plant configurations.

associated with a single outage on the transmission system. It is apparent, therefore, that the value used by Eskom for the cost of unserved energy has a direct bearing on the reliability of customer's load that is supplied by the transmission system.

New customers connecting to the system who want to have an N-1 capability in the event that a business case cannot be made, are offered the option to make up the financial shortfall in the business case as part of their connection charge. However, it would be very difficult for such customers to establish exactly what security of supply they would achieve through making any additional payments given that not all the transmission system has been built to the N-1 standard.

As a case in point of this policy, until recently Eskom has only very recently been able to make a business case for transmission reinforcement to the Cape as to do so requires sufficient customer load to be at risk in order to justify such a reinforcement economically. It is also noted that there is currently no generation in KwaZulu-Natal province and thus electricity supplies in this province are totally dependent upon the integrity of the transmission system.

Eskom produces a rolling ten-year transmission development plan, which details the transmission reinforcement, required to connect planned new generation and meet the projected load growth. The most recent plan covers the period 2006-2016. The economic justification for many new transmission projects has recently become much more robust due to the tightening of the supply/demand balance. As indicated above, one component of the economic justification is any savings in the cost of transmission losses. The value of these losses has recently risen from the marginal cost of losses to a value which factors in the capital cost of new generation capacity, resulting in a significantly higher benefit associated with some reinforcement schemes.

It is noted that in most countries, a transmission reliability standard is set taking due account of the costs and benefits associated with transmission reinforcement and, having done so, the transmission system is then planned to meet the specified criteria. Thus, for example, if the planning standard is N-1, the transmission system would be designed such that no customer would be expected to lose supply in the event of a single transmission outage. This differs from the situation in South Africa where, for those parts of the network that have not yet been reinforced to meet the N-1 standard due to the inability to produce a business case, the loss of a single line can, in certain circumstances, result in customers losing their supply.

## *6.16 Imports and Exports*

Electricity exports from South Africa to neighbouring countries over the period 2002 to 2005 are shown in Table 4.

**Table 4 – Electricity Exports From South Africa**[28]

| TWh | 2005 (15 months) | 2004 | 2003 | 2002 |
|---|---|---|---|---|
| Botswana | 2,111 | 1,699 | 1,390 | 1,124 |
| Mozambique | 10,108 | 8,076 | 5,875 | 3,907 |
| Namibia | 1,821 | 1,515 | 1,114 | 598 |
| Zimbabwe | 598 | 532 | 793 | 298 |
| Lesotho | 13 | 12 | 38 | 16 |
| Swaziland | 872 | 697 | 796 | 799 |
| Zambia | 465 | 403 | 151 | 103 |

It can be seen from Table 4 that exports to Mozambique have dominated exports from South Africa in recent years. Eskom has firm export contracts to:

- Swaziland (on a profiled MW basis);
- Botswana (on a profiled MW basis);
- Mozambique (primarily for the supply of base load energy to the Mozal 1 and 2 aluminium smelters); and
- Lesotho (a maximum of 55MW).

Eskom also has non-firm export contracts to:

- Zesco.
- Zesa.
- Namibia.

Eskom is required to give 24 hours notice of an interruption for the above non-firm contracts.

Eskom imports from the Cohora Bassa hydroelectric scheme with a contract for 1,400MW firm energy (as a base load import) plus up to 300MW non-firm energy. Imports during 2005 were some 12,000GWh.

Eskom is currently in negotiations associated with two Power Purchase Agreements associated with imports from potential new power projects in Southern Africa.

From a security of supply perspective, there are two key issues to consider:

- If there are difficulties in meeting domestic demand, to what extent can exports be curtailed?
- How reliable are the imports from each of the trading partners and what are the implications if imports were to be curtailed due to generation, transmission or political problems?

[28] Source - Eskom Annual Report.

Contractually, non-firm exports can be curtailed so long as sufficient notice is provided to the buyer and should not, therefore, have an adverse impact upon security of supply in South Africa so long as political considerations do not influence the ability to interrupt exports. For a firm contract, however, there will be a very limited set of circumstances in which curtailment is possible and thus any firm contracts do influence the security of supply. It follows that firm export contracts should only be used where there is sufficient generation capacity available to meet the obligations contained within the contract.

Eskom is currently developing a policy in which the level of total imports will be limited to its reserve margin within the context that the risk associated with each import option is to be considered on an individual basis. While it is prudent to limit imports to a level that will not jeopardise security of supply, it would also be appropriate to continuously monitor the total risk (on a probabilistic basis) associated with the portfolio of import options. This can be achieved by analysing the likelihood and extent of any given event resulting in imports being restricted. Using such an approach, an assessment could be made of whether any given import contract should be agreed given the total risk exposure from imports as a whole. It would be co-incidental if such analysis resulted in an import limit of the reserve margin.

# 7 Conclusions

The following is a summary of the conclusions from the discussion within the previous sections of this report:

## 7.1 Determination of Level of Supply Security

***Main Conclusion - There is a need for an explicitly defined generation security standard. The explicitly defined standard should be the prime determinant of the generation reserve margin, rather than using Cost of Unserved Energy (CoUE).***

Additional Conclusions:

- The probabilistic approach (as used by Eskom with its planning software) is international best practice.
- Loss of load expectation (LOLE) and loss of load probability (LOLP) are the most widely used probabilistic criteria.
- In order to calculate the reserve margin required to meet a given generation security standard, a number of underlying factors need to be taken into account.
- The reserve margin used for (long-term) planning purposes has to be somewhat greater than the operating reserve margin carried on the system (short-term), since there is a need to include uncertainties concerning demand uncertainty and generation availability in the medium to long term.
- There is a need to have an agreed and clearly defined measure of Reserve Margin that all stakeholders (Eskom, NERSA, DPE and DME) fully understand. In particular, it is important to be clear about the inclusion or otherwise of demand side management (DSM) and interruptible load (IL) contracts. Preferably, IL should be included as part of supply-side but all other demand-side measures should be part of the demand forecast, in order to avoid confusion.
- Non-Eskom generation should be taken into account in an appropriate and agreed manner when calculating the national reserve margin.
- There is a need to distinguish clearly between the reserve margin used for long term planning purposes and that required in operational time frames.

## 7.2 Responsibility for Supply Security

***Main Conclusion – The responsibility for meeting the security standard needs to be clarified, particularly in view of the Government policy whereby 30% of new generation capacity is to be provided by Independent Power Producers (IPPs) and 70% by Eskom.***

Additional Conclusions:

- There is no clear direction concerning how the obligation to supply (OTS) should be implemented, under the current policy of a 30/70 split between IPPs and Eskom.
- Currently, there is no mechanism to ensure that an agreed security standard is met and maintained over the planning period in an economic and efficient manner.

## 7.3 Transmission and Regional Security

***Main Conclusion – There is a need for transparency in any deviations from the general N-1 standard, via a derogation process from NERSA.***

Additional Conclusions:

- The current transmission security standard is N-1 but achieving this standard is contingent upon a business case being made.
- It would be appropriate for NERSA to review the South African Grid Code (SAGC) with respect to the determination of transmission security standards.
- There is a need for significantly greater transparency in transmission system planning (e.g. an annual statement, issued by the transmission system operator, showing details of load flows, with and without planned generation and load developments and their impact on system security).

## 7.4 Demand Forecasts

***Main Conclusion – Although both the ISEP and NIRP approaches to demand forecasting have merits, on balance, the "bottom-up" approach, inherent in the ISEP process is preferred. However, the whole process would benefit from an agreement on the underlying assumptions, particularly GDP growth, and the adoption of a fully unified approach.***

Additional Conclusions:

- There are a number of improvements that could be made to both demand forecasting approaches – Eskom's ISEP and NIRP (see Section 8.4 of this Report).
- Most demand forecasting scenarios indicate that demand will increase rapidly with peak demand rising at around 1,100MW/annum.
- The system load factor will remain high and thus reduce opportunity for planned maintenance of base load plant during off peak periods.
- In addition to giving consideration to the improvements suggested, it is preferable that the whole approach to demand forecasting in South Africa should be better co-ordinated and carried out under the jurisdiction of NERSA. However, rather than pursue its own independent approach, a better result is likely if the NIRP process was to involve Eskom's demand forecasting team fully, utilising the experience developed within Eskom over many years. By including Eskom in the process, the result would benefit from Eskom's experience and from the inclusion of other interested parties, rather than the present system whereby Eskom develops its own demand forecasts in a non-transparent manner and regards the results as confidential, which is not justified.

## 7.5 Generation Expansion Plans

***Main Conclusion – There is a need to address the short-term capacity shortfall, which is likely to exist for several years, in addition to planning for the longer-term. In addition, there is a need to review the generation expansion plans, particularly in view of short-term measures now being adopted to mitigate the shortfall in generating capacity.***

Additional Conclusions:

- Urgent consideration should be given to extending existing tenders for OCGT plant (Eskom and DME), with the option to convert these plants to CCGT at a later date.

- Generation expansion plans should use an explicit generation security standard agreed by Government and NERSA rather than using the CoUE as the key driver. The present approach, while theoretically elegant, suffers from great uncertainty regarding the true CoUE and does not sit comfortably with a specific reserve margin target.
- There is a need for significantly greater transparency in the generation planning process that is open to all interested parties. Eskom's argument regarding the confidentiality of this process is not justified.
- There is a need to integrate ISEP fully within NIRP, rather than having the two processes run separately.
- There is a need to ensure that short to medium term security requirements (i.e. meeting the demand over next 5 years) are dealt with in a consistent manner and as a high priority by all key stakeholders.
- Expansion planning should take full account of security of supply on a regional basis and ensure that the generation and transmission planning processes are fully integrated.

## *7.6 Imports and Exports*

***Main Conclusion – Although the international trade in electricity represents only a small proportion of the total electricity requirements for South Africa, it can have a significant effect on the generation reserve margin and hence, the security of supply.***

Additional Conclusions:

- There is a need for a transparent and inclusive review by DPE, DME and NERSA of the national policy with regard to energy exports, including the associated contractual arrangements. DME in particular need to be fully aware of the implications of exports upon security of supply within South Africa.
- There are many potential generation projects on the African continent. From a security of supply perspective, however, the reliability of such import options need to be scrutinised carefully. DPE, DME and NERSA need to be fully involved in establishing a national policy with regard to energy imports.

## *7.7 Short-Term Measures for Improving Security*

***Main Conclusion – It is far from certain that implementation of the ISEP10 plan will deliver a significant improvement in security of supply from the current level. In addition, if the return to service of mothballed plant, the commissioning of any of the new gas turbines run behind schedule or the forecast level of DSM fails to materialise, the capacity situation in the short-term will become tighter. Thus, there is an urgent need to implement measures to improve security of supply in the short-term.***

Additional Conclusions:

- In addition to considering the procurement of further OCGT peaking capacity, (see conclusion 7.5), effective DSM measures and small-scale supply-side options (e.g. diesel generators) need to be pursued.
- There is a need to "fast-track" all existing generation projects, including the return to service of the "mothballed" plant.

- There is a need for significantly greater transparency in the costs associated with the delivery of improved security of supply. In particular, it is important that stakeholders understand what action is being taken and why; and what the likely impact will be upon end-user prices. NERSA should be fully involved in this process.

## *7.8 Monitoring Supply Security*

***Main Conclusion – There is a need for effective and consistent monitoring of the supply security position and of the availability of generating plant and the transmission system. Preferably, such a monitoring system would be conducted by an independent body (e.g. NERSA).***

Additional Conclusions:

- Monitoring of generation plant availability should include non-Eskom plant, in addition to Eskom generation plant.
- There is a need to monitor, on a consistent and regular basis, forced outages on the national transmission system and particularly those that result in customer interruptions, preferably by an independent body (e.g. NERSA).
- Any perverse incentives in Eskom bonus arrangements should be avoided and the effectiveness of such schemes on the long term performance of power plant should be carefully monitored.

## *7.9 Information Transparency*

***Main Conclusion – The lack of transparency with regard to the generation and transmission planning process in South Africa is out of line with international practice and is likely to be counter-productive in meeting demand in the most effective manner.***

Additional Conclusions:

- Eskom's arguments for confidentially with regard to the information in ISEP10 is invalid and, provided adequate anonymity is maintained for sensitive projects, such plans should be available publicly.
- There is a need for much greater transparency in setting generation security standards and in the associated determination of reserve margin requirements.
- It is likely that a more open process may have revealed the serious disjoint that exists, between the long-term planning process and the process of delivering the required capacity expansions.
- There is a need for a more consistent approach towards the updating of the demand forecasts and expansion plan options.

## *7.10 Integrated Planning Process*

***Main Conclusion – The current arrangement, where Eskom's ISEP is carried out separately from the NIRP, is confusing and likely to be counter-productive in obtaining the best result. There is a need for a <u>truly</u> integrated national electricity plan, under the jurisdiction of NERSA but utilising fully Eskom's expertise.***

# 8 Recommendations

## 8.1 Determination of Level of Supply Security

Currently, there is no explicit standard established for generation security in South Africa and planned security levels are determined as an outcome of the Eskom ISEP process based upon an estimated value of the CoUE. It is recommended that an explicit security standard should be established, not driven directly by CoUE.

Based upon the analysis undertaken for this report it is recommended that, as the Ministry with ultimate responsibility for security of in South Africa, the Department of Minerals and Energy (DME) should manage the process of determining and implementing improved generation and transmission reliability standards for South Africa. This would involve the following stages:

- Undertake an analysis of the options and costs associated with a number of generation expansion plans to provide a range of reserve margins for planning purposes (e.g. between 10% and 25%).
- From the expansion plan modelling results determine the annual loss of load expectation (LOLE) associated with each plan investigated
- In line with international best practice determine an explicit generation security of supply standard. Choosing the standard would be judgemental based upon a review of the estimated incremental investment costs associated with achieving increasing levels of reliability (i.e. reducing values of LOLE).
- The security standard should be based upon a probabilistic measure of reliability such as LOLE. The security standard can then be used to establish the reserve margin required in any given year to achieve the desired value for LOLE.
- The reserve margin to be calculated on the basis that the demand-side contribution to load reduction is split into (a) Interruptible Load contracts (to be treated as supply-side options) and (b) other DSM initiatives (to be treated as modifications to demand forecast).
- Investigate the cost and benefits of reinforcing the transmission system such that the N-1 security level is met for all demand. The basis for the definition of the N-1 standard and its application in practice would need to be investigated in detail. The practical application of the N-1 standard would involve considerations such as how the standard would apply on a regional transmission basis (e.g. to conurbations over a particular size; or individual loads over a certain size).
- The costs and benefits of reinforcing the Transmission system to meet an N-2 criterion for certain key demand centres should also be explored.
- Conduct a risk analysis of all major load centres in South Africa given the current generation available and the transmission infrastructure that is in place. This would involve reviewing the impact of plausible contingencies and the various options available to secure customer supplies under such contingencies. The output of this study would be a summary of existing reliability of supply to major loads and establishing which loads are currently most at risk.

## *8.2 Responsibility for Supply Security*

As the Government Department responsible for ensuring security of supply in South Africa, the Department for Minerals and Energy (DME) needs to ensure that the institutional arrangements for supply security are effective. It is also appropriate that DME should facilitate the delivery of the agreed security standard. It is recommended that:

- DME should ensure that, at all times, a plan is in place for the security standard to be met and maintained over the planning period in an economic and efficient manner.
- Given that DME has determined the 70/30 policy with respect to new generation, DME should therefore ensure that the means are available to implement this policy and that arrangements are in place for 100% of South Africa's generation requirements to be delivered in a timely manner.
- NERSA should continue to be responsible for managing the expansion plan. However, NIRP should be integrated with the ISEP process (see recommendation 8.10).
- Eskom should be responsible for maintaining security of supply at a reliability standard to be established by DME.
- Eskom should deliver its obligation for security by building or procuring of up to 70% of all new generation plant identified in the (truly integrated) expansion plan and for contracting for the remainder (at least 30%) from IPPs.
- DME should continue to be responsible for running the IPP tender rounds for at least 30% of capacity identified in the expansion plan.

## *8.3 Transmission and Regional Security*

It is recommended that any deviation from the N-1 transmission security standard in the South African Grid Code should require specific derogation, approved by NERSA. It would be appropriate for NERSA to review the South African Grid Code (SAGC) with respect to the determination of transmission security standards.

It is also recommended that system security should be planned, implemented and monitored on a regional basis, to identify any regions where security is below the specified standard and where additional security may be required.

There is a need for significantly greater transparency in transmission system planning (e.g. an annual statement, issued by the transmission system operator, showing details of load flows, with and without planned generation and load developments and their impact on system security).

## *8.4 Demand Forecasts*

It is recommended that there should be an agreed central case assumption, within the electricity industry, about the level of economic growth that the industry is preparing to meet.

It is recommended that, within the overall planning process, the demand forecasting should be based primarily on a "bottom-up" approach.

In addition, the following detailed recommendations are based on the analysis outlined in Sections 6.5 and 6.6 of this Report:

- Eskom and NERSA should consider a basis for improving the demand forecasting and monitoring processes by co-ordinating data on a full sector basis, across all distributors.
- Future ISEP reports should show the full table of results for all scenarios and all demand forecasts should include the latest actual year's energy and peak demand as the points of reference.
- Future ISEP reports should show a breakdown of the demand forecast for each of the major sales sectors, at least for the most likely scenario.
- Future ISEP reports should indicate clearly the assumed level of transmission and distribution losses for each year of the planning period and for each scenario separately, stating the rationale for any changes in the percentage level from year to year.
- Until there is clear evidence that DSM programmes actually deliver demand reductions and that no double counting is involved, the contribution from DSM initiatives should be ignored in producing demand forecasts.
- For as long as capacity shortages exist, considerable effort should be devoted to maximising the availability and use of interruptible load contracts, recognising the cost of losing such valuable contributions to peak demand reduction.
- Eskom should carry out a more robust study of the impact of weather on demand and produce weather corrected peak demand values, to indicate the impact of either cold or mild winters in any particular year. It is also recommended that Eskom should show, in ISEP Reports, a separate identification of the impact of severe weather on the demand forecasts, rather than include weather impact within a general range of uncertainty. This is because severe weather is less likely to occur several years in succession than other uncertainties included in the general range of forecast uncertainty.
- For future ISEP Reports, a full explanation should be provided of what sensitivity tests have been applied to each demand forecast scenario, together with a complete data set for each (as an Appendix). Where a range is shown for a demand forecasts, a rationale for the range should be provided, including an estimate of the confidence levels associated with each range. In addition, it would be helpful to include a "laymen's summary" of the demand forecast scenarios and the results of the sensitivity tests, to indicate the following:
  - *Which scenario Eskom believes to be the most likely scenario and why.*
  - *How the sensitivity tests impact on the overall demand forecasts and the extent to which it would be prudent to allow for a higher level of demand than the central level of the most likely scenario, together with a broad view of the costs involved.*
- Future ISEP reports should include a comparison of actual (weather corrected) demands with forecasts made, say, 5 years previously, in order to provide a reasonable view of Eskom's demand forecasting accuracy and how it has improved over the years.

## *8.5 Generation Expansion Plans*

It is recommended that the economic impact on long-term plans should be reviewed in the light of the short-term measures now being taken to address the security shortfall.

It is recommended that urgent consideration should be given to extending the capacity of existing tenders for OCGT plant (Eskom and DME), with the option to convert to CCGT at a later date. Subject to the outcome of the recommended studies on risk analysis and security costs and benefits (see recommendation 8.1), the procurement of up to 3000 MW of new OCGT plant (achieved through a combination of Eskom procurement and IPP contracts to Eskom) should be considered.

It is recommended that generation expansion plans should use an explicit generation security standard agreed by Government and NERSA rather than using the CoUE as the key driver. The present approach, while theoretically elegant, suffers from great uncertainty regarding the true CoUE and does not sit comfortably with a specific reserve margin target.

It is recommended that expansion planning should take full account of security of supply on a regional basis and ensure that the generation and transmission planning processes are fully integrated.

## 8.6 Imports and Exports

It is recommended that, in view of the potentially significant impact on the reserve margin and hence on the security of supply, a transparent and inclusive review should take place of the national policy with regard to energy exports, including the associated contractual arrangements.

It is recommended that the reliability of import arrangements and the associated risks to supply security should be monitored continuously on a probabilistic basis.

## 8.7 Short-Term Measures for Improving Security

It is recommended to adopt a “fast-track” approach with regard to current generation and transmission expansion projects, to mitigate the impact of delays and accelerate the programmes wherever possible and to consider the procurement of diesel generators for installation at strategic points on the distribution networks as a contingency option.

It is recommended that, in addition to procuring additional OCGT peaking capacity (see recommendation 8.5), effective Demand-Side Management (DSM) measures be pursued to reduce demand in the short-term. There are a number of measures that can be introduced in the short term to alleviate the problems currently being experienced, such as:

- Further media campaigns involving requests for customers to reduce thermostat levels, improve insulation, and install energy-efficient lighting, motors and fridges.
- Customers should be encouraged to switch off freezers, water heaters, etc during peaks demand periods and to turn off standby operation on electronic equipment.
- While supply shortages exist, customers should be encouraged to switch to gas for cooking.
- In the short to medium term, there would be a benefit in encouraging demand diversity by customers through the introduction of flexitime, changes to holiday arrangements etc. and by the introduction of tariff incentives for peak shifting by medium-size industrial/commercial customers (1-10 MW).

- The introduction of customer rebates for reductions in demand or meeting standards of insulation in homes and buildings should be considered.

## 8.8 Monitoring Supply Security

It is recommended that consistent and regular monitoring should be carried out by an independent body (e.g. NERSA) of:

- The generation reserve margin; and
- The availability of generation plant (Eskom and non-Eskom) and the transmission circuits.

It is recommended that the existing anomalies in the definition of reserve margin be removed such that:

- Demand-side measures should be included in the demand forecasts but interruptible load contracts be part of the generation margin; and
- The distinction between operational reserve and planning reserve margin is clarified.

It is also recommended that monitoring should take place, on a consistent and regular basis, of forced outages on the national transmission system and particularly those that result in customer interruptions, preferably by an independent body (e.g. NERSA). In addition, any perverse incentives in Eskom bonus arrangements should be avoided and the effectiveness of such schemes on the long term performance of power plant should be carefully monitored.

## 8.9 Information Transparency

In all of the other markets reviewed as part of this study, there is a significant amount of information in the public domain concerning security of supply and reserve margin. By contrast, in South Africa, almost all of Eskom's documents on security of supply and reserve margin are either unpublished or specifically deemed to be confidential to Eskom. That is unfortunate, since it creates an air of secrecy about issues that should be open to debate among interested parties. Whilst the NIRP results are in the public domain, these results tend to be published later than Eskom's ISEP and, consequently, the most up to date information is not available for public consideration.

Eskom may argue that their ISEP results are confidential but that argument is invalid, particularly for a dominant state-owned entity not in competition with other utilities. International experience shows that in both competitive and monopolistic markets, the type of information produced in Eskom's ISEP is deemed to be public domain information, in order to ensure that all interested parties are aware of the plans, issues and options under consideration.

For a number of years, the Eskom ISEP process was largely theoretical, since, due to the surplus generating plant capacity that existed for many years, no decision on new plant extension was required in the near future in order to meet increased demand. That situation is past and now, demand forecasts and expansion plans are very real inputs to a decision making process on building new generation plant capacity. It is also likely that a more open process may have revealed the serious disjoint that exists, between the long-term planning process and the process of delivering the required capacity expansions. Bearing in mind that new capacity should have been in service by around 2005 and that coal plant has a lead time, from the planning process, of 7-8 years, the preparations for new capacity should have been in process since the mid-1990s. Indeed, it may be that new coal plant may even have been more economic than the return to service of the mothballed plant. The lessons are that, where real decisions are being made, it is vital that the plans and assumptions behind the plans have the widest possible exposure to enable alternative ideas and options to be considered. Eskom does not have a monopoly on good ideas.

It is therefore strongly recommended that Eskom's ISEP results, together with the associated procedures and policies, should be published in full. However, it is recognised that there may be circumstances where certain information may need to be kept anonymous for reasons of commercial confidentiality.

In addition to making the ISEP process fully available to the public, it is recommended that a more consistent approach be taken towards the updating of the ISEP demand forecasts and expansion plan options. It is recommended that a demand forecast should be updated at least annually, possibly at some point soon after the actual winter peak demand has been established. A revised expansion plan should be produced immediately following the production of the revised demand forecast. These forecasts and plans should cover a 20-year time horizon. The detailed recommendations concerning demand forecasts and expansion plans should be incorporated into the revised timetable. It is also recommended that each annual revision should contain a section devoted to the explanation of the changes from the previous forecast and expansion plan options. This should be on a consistent basis, so that each year, it is possible to identify clearly the changes from year to another and the reasons behind the changes.

## 8.10 Integrated Planning Process

The NIRP process is relatively new and was initiated at a time when a competitive market for power was being considered for South Africa; when Eskom was to be part privatised; and all new generating plant was to be built by the private sector. All that changed in 2004 with the new policy concerning Eskom and other state-owned enterprises. Unfortunately, it leaves an uncertain and possibly confusing position with regard to what exactly is the planning process for South Africa's electricity system. On the one hand, NIRP produces a national plan for generation expansion, with no mandate on who is to provide the new plant capacity. Meanwhile, Eskom produces its ISEP, making certain assumptions about IPPs but is not necessarily consistent with NIRP. That is clearly unsatisfactory, particularly in the current situation where construction of new generating capacity is required urgently.

It is recommended that the DPE should initiate discussions with NERSA, Eskom and all interested parties with a view to integrating the ISEP and NIRP processes into one seamless national process, with the following attributes:

- Fully consistent definitions (demand, generation, DSM, reserve margin, etc.).
- Demand forecast scenarios, based on agreed criteria and historic demand information that includes data from all distributor/retailers on a consistent and agreed sector breakdown.
- An explicit probabilistically based security standard, set form time to time by the process set out above in recommendation 8.1.

- Demand-side measures that are evaluated to be more economic than an OCGT, to be included in plans for implementation.
- A series of parameters for candidate expansion supply-side options, with indicative costs.
- A model to evaluate the alternative supply-side options.
- An agreed set of sensitivity tests on the basic assumptions.
- A preferred plan, based on the output of the expansion plan results.
- Alternative plans for implementation in the event of specified contingencies.
- A consistent update to the above process at least annually and at other times as may be required.
- All data and models to be made available to any interested parties.

It is recommended that the single integrated planning process be managed and co-ordinated by NERSA, with Eskom being responsible for agreed components of the plan. The outputs from this plan should be made public at least on an annual basis and more frequently if specific circumstances require it. In particular, in a period where the supply situation is tight, it is vital that such information is in the public domain on a timely basis.

## *8.11 Critical Factors for Implementation of Recommendations*

The following table provides a brief summary of the critical factors involved in the implementation of the above recommendations. The numbers in the table refer to the paragraph numbers in this section of the report.

**Table 5 – Critical Factors for Implementation**

| | Recommendation | Critical Factors | Entities Involved |
|---|---|---|---|
| 8.1 | Determination of Level of Supply Security | Manage the process of analysing the options and costs of different levels of security and determine an appropriate level to adopt. | DME, NERSA, Eskom, DPE |
| 8.2 | Responsibility for Supply Security | Clarify the obligation to supply and the responsibility to build/procure capacity under the 70/30 policy. | DME, NERSA, Eskom, DPE |
| 8.3 | Transmission and Regional Security | Review the South African Grid Code, specifically to include a derogation requirement to deviate from the normal N-1 standard and to ensure transparency. | NERSA, Eskom |
| 8.4 | Demand Forecasts | Agree central assumptions on GDP growth and integrate the demand forecasting processes of ISEP and NIRP, primarily based on a “bottom-up” approach. | NERSA, Eskom |
| 8.5 | Generation Expansion Plans | Review expansion plans in light of short-term measures, consider urgent procurement of additional OCGT plant and plan on a regional basis. | NERSA, DME, Eskom, DPE |

| | Recommendation | Critical Factors | Entities Involved |
|---|---|---|---|
| 8.6 | Imports and Exports | Review export contractual commitments and analyse import arrangements on basis of probabilistic risk. | Eskom, NERSA, DME, DPE |
| 8.7 | Short-Term Measures for Improving Security | Fast-track existing generation and transmission projects, step up DSM arrangements and consider diesel generation procurement. | DME, Eskom, NERSA, DPE |
| 8.8 | Monitoring Supply Security | Set up monitoring system for reserve margin, plant and system availability and major outages, with agreed definitions. | NERSA, Eskom, DME |
| 8.9 | Information Transparency | Publication of ISEP results and all associated planning information. | DPE, Eskom, NERSA |
| 8.10 | Integrated Planning Process | Integrate the separate ISEP and NIRP processes. | DPE, NERSA, Eskom |

# Appendix A - Reliability Criteria used for Power Systems

There are many different methods of calculating and expressing the reliability of a power system. Different utilities use different criteria for planning targets and comparison between utilities is not straightforward. Reliability criteria for power system planning purposes include the following:

### Loss of Load Probability (LOLP)

LOLP is defined as the probability that load will exceed available generation. The primary reason for its use is the relatively small amount of data required and the ease of calculation. While LOLP provides the likelihood of encountering difficulty on a system, it does not indicate the severity, either in terms of capacity or energy shortage. Many utilities no longer use LOLP as a planning criterion, as it is more difficult to interpret and has less physical significance than other techniques.

### Loss of Load Expectation (LOLE)

LOLE, a variant of LOLP, is one of the most widely used probabilistic indices in planning future generation capacity. It has been in use by a large number of utilities for many years. LOLE can be defined either as:

- The average number of days in the year on which the daily peak load is expected to exceed available generating capacity; or
- The average number of hours in the year for which load is expected to exceed available generating capacity.

LOLE therefore indicates the days (or hours) for which a generation deficiency may occur. It has a physical significance, which is absent in the LOLP criteria. Due to the small quantity of data used, the LOLE criterion does not usually reflect actual expected outages but rather can only be considered as a relative measure. (For example, an LOLE index of 2.0 shows that failures to supply will be twice as likely as with a LOLE index of 1.0 but one would not know how severe either would be).

It is difficult to compare LOLE indices of different utilities. Each utility may have made simplifying assumptions that would apply only to that utility. These assumptions can include the way in which the load is considered or how the generating plant characteristics are used. These simplifications do not lessen the value of the LOLE criterion as long as it is treated as a relative measure. It does however make it difficult to directly compare the indices of different utilities.

### Expected Energy Not Supplied (EENS)

The EENS method defines the expectation of energy that the utility will be unable to supply on those occasions when the load exceeds available generation. This index has the advantage over LOLE in that it encompasses the severity of deficiencies as well as their likelihood. Two other criteria, Loss of Energy Expectation (LOEE), and Expected Unserved Energy (EUE) are essentially the same as EENS. The primary disadvantage of EENS and its variants is the significant amount of data required to undertake the analysis.

## Frequency and Duration (F & D) index

The F & D criterion identifies the expected frequency of generation shortfall and the expected duration. It therefore contains additional physical characteristics but, in most cases where the supply of electricity has to be curtailed due to generation capacity shortages, the curtailment is shared between customers on a rotational basis. This reduces the relevance to individual customers of these more complex measures. Due to their lack of focus and large amount of data required these indices have not found much favour with utilities.

There is the potential for considerable confusion regarding the specific meaning of expectation indices and how they can, or should, be used. A single expected value is not a deterministic parameter. Rather it is the expectation associated with a probability distribution and is, therefore, a long run average value. The above expectation indices provide valid indicators of the adequacy of a power system that reflect such factors as the size of generating units, the maintenance requirements, the load characteristics and load forecast uncertainty.

Due to the random nature of failures in generating plant, power utility reliability criteria are generally probabilistic in nature. Visualising the implication of failing to meet a given criterion is not immediately apparent from the criterion itself. Any decision to postpone the construction of new plant implies a reduction in system reliability. On the other hand, minor infringements of the criterion do not bring about a sudden or dramatic reduction in the security of supply. In making a decision regarding new capacity it is necessary to be aware of the magnitude of the risk of generation shortfall and the implication of such a shortfall, were it to occur.

### Definitions

The detailed definitions used in defining power system security standards vary around the world, however, typical definitions used in practice are as follows:

***Reliability*** – a general term encompassing all the measures of the ability of the power system, generally provided as numerical indices, to deliver electricity to all points of utilisation within acceptable technical standards and in the amounts desired. Power system reliability (comprising generation and transmission facilities) can be described by two basic and functional attributes: adequacy and security.

***Adequacy*** – a measure of the ability of the power system to supply the aggregate electric power and energy requirements of the customers within component ratings and voltage limits, taking into account planned and unplanned outages of system components. Adequacy measures the capability of the power system to supply the load in all the steady states in which the power system may exist considering standard conditions.

***Security*** – a measure of power system ability to withstand sudden disturbances such as electric short circuits or unanticipated losses of system components or load conditions together with operating constraints. Another aspect of security is system integrity, which is the ability to maintain interconnected operations. Integrity relates to the preservation of interconnected system operation, or the avoidance of uncontrolled separation, in the presence of specified severe disturbances.

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