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Special AMEU Proceedings Edition

SPECIAL ISSUE

AMEU 21st Technical Convention

Gallagher Estate • Midrand • 16 - 18 October 2006

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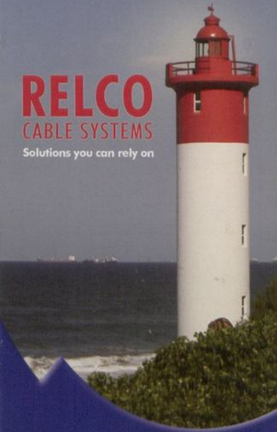

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Aberdare Cables - a leading manufacturer of cables

Information from Aberdare Cables

Aberdare Cables, a member of the Powertech Group, is a leading African manufacturer of cables with five manufacturing sites, in three provinces of South Africa, and offshore operations in Mozambique, Portugal and Spain.

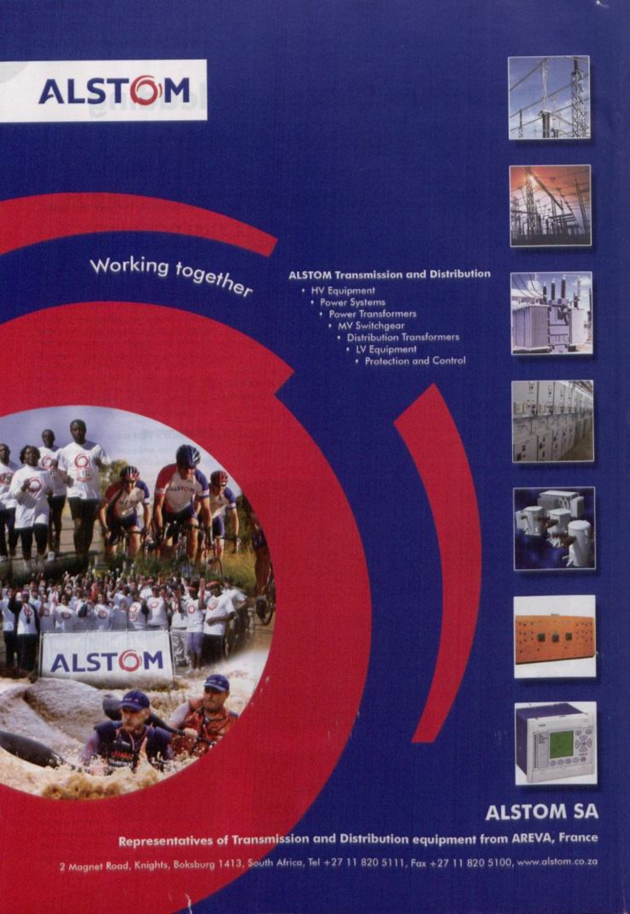
The company's customer base includes power supply authorities, railway and transport organisations, municipalities, and companies in industries such as petrochemical, mining, wholesale, industrial, construction and domestic building. The company manufactures and sells a wide range of state of the art products with customer specific adaptation, design capabilities and full technical back-up service. Aberdare Cables prides its self on its ability to identify and satisfy customer needs through development of innovative products; unique, cost effective cable solutions for a wide range of industries. This and their extensive project experience make them the supplier of choice for cable, related accessories and special cable projects. Aberdare Cables pursues ongoing technology development programmes, and through active association with its local and overseas affiliates, continues to remain at the forefront of technology. The company has been recognised internationally as a pioneer in cable advancements. Aberdare serves on a number of SABS and International Electro Technical Commission (IEC) cable working groups. As much as ten years ago, in a move towards facilitating the provision of electricity for all countrywide, Aberdare Cables designed products with an emphasis on cost efficiency of electrification.

To this end, Aberdare created its Electrodac range, which is aimed specifically at facilitating rural electrification by lowering the cost of electricity delivery. More recently, in accordance with Siemens specifications, Aberdare produced an un-amoured cable, with stringent fire characteristics, that was designed to reduce the propagation of fire by cables. This cable is used at Eskom's open-cycle gas turbine generators at Mossel Bay and Atlantis. To cater for international markets, Aberdare introduced fire survival cable with stringent properties that allow continuous operation and circuit integrity for extended periods during a fire. Aberdare Cables is a fore runner in the industry with regard to quality. The manufacturing, quality assurance, testing and research resources of Aberdare are of a world-class standard. In fact, the company was one of the first companies in South Africa to be awarded the South African Bureau of Standards (SABS) Quality Assurance Certification, and has been ISO 9001 compliant for many years. Aberdare Cables is UL listed and has Basec QA accreditation.

Transformation

Aberdare has embraced the empowerment concept. Today, 30% of the company is owned by Izingwe Consortium and the company has assisted in the development of a number of black enterprises, such as Drumco, the company that makes Aberdare Cable Drums.

Aberdare Cables has always been an active supporter and pillar of strength for the communities in which it operates. The company is championing a number of social investment initiatives across our country. The biggest of these investments has been the continuous sponsorship of Sinithemba home for street children in Port Elizabeth. On-going supply of the equipment necessary to create the sense of self sufficiency and pride that the Abercare Centre, for mentally and physically disables people in Pietermaritzburg, provides its members. An investment of R1 million in computer workstqtions for a new computer laboratory at the Nelson Mandela Metropolitan University that will allow students from disadvantaged backgrounds access to vital computer amenities. Half a million Rand investment into an administration block at the Charles Duna School in New Brighton. Contonuous provision of equipment and materials to Sunfield Homes, in Johannesburg, for the assembly of Moon Lights and cable end caps, which the home sells. As a proudly South African company, Aberdare participated actively in the development of the ICT charter and the draft DTI BBBEE codes. Aberdare will continue to adopt a proactive approach to effect the transformation that the codes specify and to lead the cable industry in this regard. Δ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AMEU Proceedings

21st Technical Convention • Gallagher Estate • Midrand

"Electricity service delivery - the challenge"

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Opening address

by AMEU president, Vally Padayachee

Clr. Molwele representing the executive mayor of the City of Johannesburg; the speaker of the City of Johannesburg, Clr. Ntigane; the MMC of the City of Johannesburg for infrastructure and services, Clr. Greef; councillors from the various metros and munics; the city manager of the City of Johannesburg, Mr. Mavela Dlamini; Prof. Ravi Nayagar, CEO of ECSA and our keynote speaker; deputy president of the AMEU, Sandile Maphumulo from eThekwini Metro; vice president of the AMEU, Sy Gourah from Buffalo City; the acting chairperson of the City Power board, Mrs. Getty Simelane; the acting managing director of City Power, Silas Zimu; distinguished and honoured guests.

Sanibonani, dumelang, goeie more and a very good morning to you. I want on behalf of the AMEU to take this opportunity of extending to all of you a very warm and cordial welcome to this great city of Johannesburg.

Lots of you have come from far and wide and it's a pleasure to inform you that this year's convention has been a record in terms of delegate registration and booking of exhibition space.

I guess the latter is an indication of all of us trying to find solutions to the many problems and challenges facing us individually and collectively as an industry.

Furthermore, we also this year had the luxury of turning away papers because in essence we were kind of overscribed.

Some of the criteria that the papers committee of the AMEU used included the need to give all stakeholders within our environment and industry e.g. government, suppliers, utilities, municipalities, consultants, etc. an opportunity to present. Our convention theme for this year as you know is "Electricity service delivery – the challenge".

In carefully selecting this theme the AMEU took cognizance of some of the following challenges:

- The acceleration of electricity service delivery in a cost effective, efficient, effective and safe manner to all who need it especially the poorest of the poor
- The restructuring of the industry and especially with the impending creation of the REDs (regional electricity distributors)
- The provision of an adequate and "sound" physical asset infrastructure to deliver power to both existing and potential new customers in a sustainable and reliable manner
- Security and adequacy of generation power supply or capacity
- Demand side management and energy efficiency
- The growing shortage of relevant skills and competencies together with the associated training and development challenges
- The availability of much needed funding to cater for all the stated challenges
- The use of alternative and renewable energy resources within the distributed energy environment
- The use of various but relevant technologies to address the various challenges

I am hoping that the papers that are being presented and the ensuing questions, discussions, etc will seek to address some (if not all) of the above challenges.

The AMEU in its current 91st year of existence has always sought to provide assistance in the course of its various activities and interventions - its seminars, publications, branch meetings, website, etc.

I hope you enjoy your stay in Johannesburg and look forward to personally meeting you during the convention. Δ

Welcome by the Mayor

presented by Councillor Roslyn Greeff, MMC, City of Johannesburg

Presented on behalf of the executive mayor Clr. Amos Masondo by Clr. Roslyn Greeff, member of the mayoral committee (MMC) responsible for infrastructure and services in the City of Johannesburg.

Programme director, resident of the AMEU, madame speaker, chairperson of the ISD portfolio committee, mayors and MMC's from other metro councils, city manager, distinguished guests, ladies and gentlemen.

It is a pleasure to be with you here tonight and to welcome the AMEU delegates from across the country to the City of Johannesburg. We in Johannesburg have indeed had ample reason to celebrate in recent weeks as we recalled the formal establishment of the city, a mere 120 years ago. There has been human settlement in this area for close to a thousand years. The excavations at the Klipriviersberg Nature Reserve and Melville Koppies have uncovered evidence of human habitation dating back to 1060. And by the 1700s there were already several well established settlements in the areas that are known today as Northcliff, Bruma, Melville and Lonehill.

Since formal proclamation in 1886, a small mining town has grown into Africa's premier city in the very short space of 120 years. After all, most of the world's famous cities have evolved over hundreds, if not thousands, of years. So, Johannesburg, by comparison, grew from a tent town to wood and iron shanties, then to brick and mortar buildings at the pace of an historical wink of an eye. Within two decades of its formal proclamation, the broad outlines of the city as we know it today, were already well established.

We as a city have so much to be proud of. We have truly established a world class city, which can compete on almost any level with our counterparts across the globe, in a very short space of time. And very little of this could have been achieved without the vision, the knowledge, the technical expertise and the dedication of the various engineering professions – especially the electrical engineers.

I have the highest regard for your profession and your work environment – your job is to light up our lives, literally. Electricity is the single, most visible, proof of service delivery by any local government. If the lights are off, the city descends into a pall of gloom and cabinet ministers start looking for missing bolts in faulty generators. In Johannesburg we are working at a frantic pace just to catch up with existing backlogs and the replacement of old infrastructure – some dating back to the 1940s and 50s. At the same time, we are dealing with the "growing pains" of a very young city.

Every week we see the establishment of new housing developments, the construction of new shopping centres, new places of entertainment, new community facilities. All of these devour electricity as fast as we can supply it. With an economic growth rate of almost 5% the city is expanding at a rapid pace. The current projections are that the number of households in the city may reach the two million mark by 2012 – double the number at the turn of the century. At the same time we have to deal with the reality that very little was done in the 1980s and early 1990s to prepare the city for the current economic boom and growth in population. The City of Johannesburg has committed more than R8-billion for infrastructure development to ensure that Johannesburg's entire power network is overhauled within the next decade.

As you can see, ladies and gentlemen, we are not running away from our responsibilities. On the contrary, our talented and tireless men and women are coming forward with innovative solutions and practical alternatives to solve very vexed and complex problems. Your conference also takes place against the backdrop of a rapidly changing environment in the delivery of electricity services. By this time next year the JORED will be a reality and the Gauteng premier's vision of the province as a global city region will become bigger on our radar screen with each passing month.

In my brief tenure as MMC in the city, I have come to know electrical engineers and the members of AMEU as a special breed of people. For them, there is no challenge too big, no crisis too daunting. Ladies and gentlemen, I trust that you will enjoy your stay in Johannesburg, and that you will have a very productive conference and that your decisions and resolutions will enable us as the administrators keep up with the rapid development of our beautiful country.

I thank you. Δ

Speech by the Mayor

presented by Clr. Nonceba Molwele, chairperson of the Johannesburg Infrastructure andServices Portfolio Committee (representing the executive mayor of Jhb) on the occasion of the 21st AMEU Technical Convention at Gallagher Estate.

The speaker of the City of Johannesburg, Clr. Nkele Ntigane, members of the Johannesburg mayoral committee, the city manager for Johannesburg, Mr. Mavela Dlamini, the president of the AMEU, Mr. Vally Padayachee, the deputy and vice presidents of the AMEU, councillors and officials from other metros and municipalities, distinguished guests, ladies and gentlemen.

At the outset I want to apologise on behalf of our executive mayor, councillor Amos Masondo, who could not attend this morning. He was called to an urgent meeting with the MEC for local government. I also want to take this opportunity of welcoming all delegates to the beautiful and vibrant city of Johannesburg. I also want to congratulate the AMEU in its ninety-first year of existence and for hosting its twenty-first technical convention. Your longevity reflects an organization that is richly steeped in history with a tough and resilient record. I am also very impressed by the theme for this convention namely "electricity service delivery - the challenge". Service delivery in the electricity industry is indeed a huge challenge not only in South Africa but across the globe. I am therefore happy that this convention has chosen to confront this challenge head-on and at this specific stage of our country's and city's history. There can indeed never be a better time to deal with this challenge than right now and there are indeed no better people to deal with this matter than the ladies and gentleman in this room right now.

I am confident that you will rise to the challenge posed by rapid urban development and growing demands for services such as electricity and power. We will be looking at the outcomes of this convention against what we in Johannesburg call the six mayoral priorities and also against our growth and development strategies. Looking at your conference programme I have noted that you focus predominantly on the challenges we are encountering today and in the future. These include challenges like the integrity of infrastructure, tariff methodologies and free basic electricity. These issues are central to the city's ability to reach the objectives set in the growth and development strategy. I am convinced that we have assembled in this conference the skills, knowledge and the competencies that the country needs to get to where we want to go. The priorities that you have identified are also in line with our priorities in the country's largest and fastest growing urban environment.

Economic growth and job creation

It is common knowledge that reliable electricity supply plays a key role in to economic growth and job creation. I am confident that this convention will be dealing with such matters as, for example, the future of prepayment meters, the development and enhancement of technical skills, the refurbishment of the network and security, the adequacy of supply and industry restructuring. It is important for an organization like the AMEU to play its rightful role in finding ways and means of improving, upgrading and technologically advancing our electricity supply systems. It is for this reason that we in Johannesburg are happy to host this convention because we believe that the outcome of your discussions will help us to improve our community and health facilities.

We cannot hope to improve the lives of our people and communities without a good and reliable supply of electricity. Electricity has enabled our people to start small businesses in their homes and in the business centers that the city is developing. The safety levels also improve as more and more streetlights are installed across the City of Johannesburg. We believe that we have built a solid foundation upon which we can continue to light up and improve the quality of the lives of our people and it is for this reason that we fully support your efforts and believe that the outcomes of your deliberations should be spread across South Africa and indeed across the African continent. We in Johannesburg also believe that we will enjoy our improved services if our neighbours have access to similar services. Although we believe that this is important we also believe that a leadership position is our rightful position and that it is where we belong as a city and as the people of Johannesburg.

Housing and services

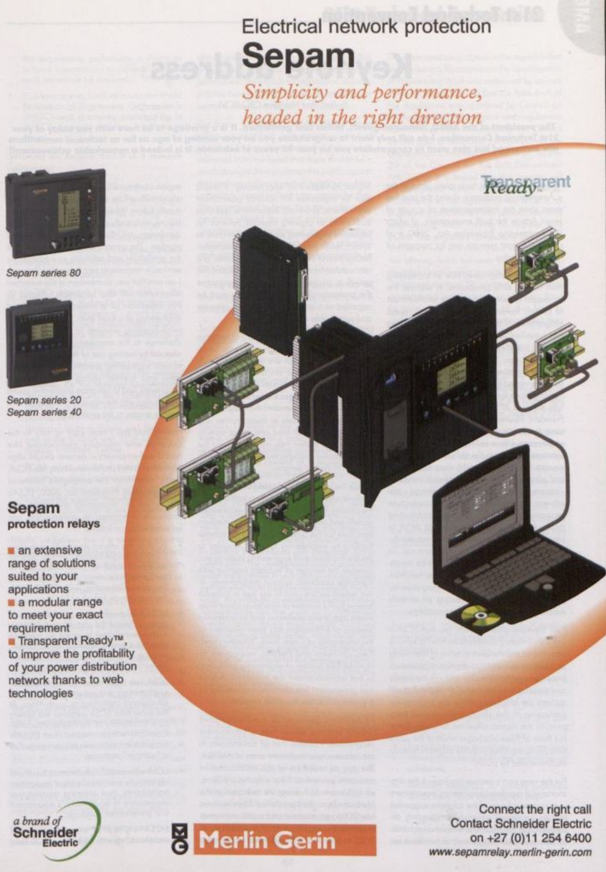
As engineers you would have engaged in one of those debates where people argue about the difference between a house and a home. For a non-technical person like me the two have always been synonymous until I encountered people like yourselves who convinced me that not every house is a home and that a home is supposed to give more comfort than a house. I therefore concluded that if this is the case, electricity and services like running water, the ablution system and refuse removal must be some of the major things that convert houses into homes. It is for this reason that I was happy when I saw that among some of the things you will be talking about in this convention are issues like free basic electricity and tariffs for domestic customers. Cabinet has approved the implementation of the Extended Public Works Programme purely to create a way that would allow our economy to open opportunities for unemployed people and to create empowerment opportunities for them. We know that the majority of people do not like the idea of standing in the streets and begging for assistance but would rather earn their livelihoods. The Extended Public Works Programme will allow companies to create spaces for people who are looking for employment or business opportunities. I am therefore appealing to you that as you engage with matters of energy you should always keep in mind some of the challenges that may be seen to be outside your scope, but can have an impact on the entire economy including electricity supply.

The creation of JORED or RED 4

Today Johannesburg is also looking at implementing what we have come to call JORED or RED 4 to ensure that we can take service delivery closer to the people. This, we believe, will ensure that electricity supply is at a level where even the poor residents can access it much easier. The JORED will come into operation in Johannesburg within the next six months and is bound to change the entire concept of electricity delivery to our residents.

The growth and development strategy

Johannesburg and the country as a whole is striving to decrease or close the gap between the first economy ("the haves") and the second economy ("the have-nots"). We cannot allow this gap to widen. To address this perplexing problem the CoJ has inter alia implemented or is planning to implement various programmes in line with the city's growth and development strategy. In this regard we have committed ourselves to electrify over 95% of all the formalised homes within the next five years and we are confident that we will achieve this objective. I trust that your discussions at this conference will focus on this important issue and support us in our efforts to reach these targets in advance of the deadlines we have set. I am also hoping that this convention will further deliberate such challenging issues as reduction of power outages, the betterment of public lighting, the reduction of non technical losses, the security and adequacy of power supply, alternative energy sources, and demand side management. In closing I want to also take this opportunity of wishing you all the very best in your deliberations for the next three days and we trust that those of you that are visitors to our great city will thoroughly enjoy your stay here. Δ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Keynote address

by Prof. Ravi Nayagar, CEO ECSA

The president of the AMEU, honoured guests, ladies and gentlemen. It is a privilege to be here with you today at your 21st Technical Convention. I do not only want to congratulate you on your coming of age as far as technical conventions are concerned but also want to congratulate you on your 90 years of existence. It is indeed a remarkable achievement!

Significant changes have taken place in the engineering profession during the past five years since the implementation of a suite of seven Acts in the built environment, of which the Engineering Profession Act, 2000 is of course the most relevant one for purposes of my address today.

The question is often asked how SA is preparing itself from a skills perspective to address the envisaged massive infrastructure refurbishment of Eskom, Transnet and the Gautrans capital programmes of the day. As you know, cabinet has unveiled the Accelerated and Shared Growth Initiative for South Africa (ASGISA) in July last year. You may also be aware that the Joint Initiative for Priority Skills Acquisition (JIPSA) is viewed by government as an important building block for ASGISA. In this regard ECSA fully supports JIPSA which is driven by Deputy President Phumzile Mlambo-Nqcuka. JIPSA aims to identify urgent skills needs such as engineering with a bid to implement effective solutions to address the skills shortage in our country. As high-level, world- class engineering and planning skills for the network industries - transport, communications and energy - are all very much at the core of infrastructure programmes, ECSA is actively contributing to the technical working group of JIPSA in identifying blockages and, more importantly, seeking solutions to this vexing process. In addition I am sure that AMEU will be aware that another important working area for JIPSA is the city, urban and regional planning capacity with its concomitant engineering set of skills desperately needed by our municipalities.

I am therefore glad to inform you that ECSA is currently collating contributions from its various and diverse stakeholders in terms of identifying problem areas in order to develop at grassroots level a comprehensive plan that will concretely and practically mount a set of strategies that will address the blockages within the engineering profession in the short, medium and long term. In this regard allow me to briefly name but three of these blockages whilst at the same time proffering three possible solutions already recommended by ECSA.

For the most part a serious blockage is the dire shortage of registered engineering practitioners in our country. Some of the solutions suggested include increased government spending on infrastructure development, when market forces of demand and supply will naturally draw higher numbers into engineering. It would also be imperative for national government departments, provincial departments and local authorities to urgently improve salaries for registered engineering professionals in order to attract, retain and build engineering expertise. Recognition of the engineering practitioner as a vital catalyst for engendering greater economic growth is crucial. From an ECSA perspective the professional engineering family must be regarded as a national asset, driving progress and sustainable development.

Secondly, we can look at the situation of restrictive processes and systems in the workplace. Some of the quick fixes that are suggested are to revert from a lowest priced tender system to reasonably-priced tender system with the emphasis on quality, track record and meeting specifications. Procurement and supply chain management processes at municipalities and the reintroduction of tried and tested systems like the roster system may result in at least the locus of control resting in technical departments and not in central services.

Thirdly the low intake and output of engineering students and graduates at tertiary institutions in the country is a severe blockage to accelerated growth and development. One of the medium term fixes for this blockage may be to increase funding to engineering facilities in order to double the number of engineering students and increase the number of lecturers together with adequate academic support programmes. In this regard we are glad to say that in a media release by the minister of education about three weeks ago, it was confirmed that an additional amount of R48-million has been allocated to the universities of Cape Town, Witwatersrand, KwaZulu-Natal and Pretoria, respectively to increase their number of engineering graduates. In her announcement the minister indicated that government has identified engineering as a scarce skill within the JIPSA initiative.

As ASGISA is perceived as a national shared growth initiative rather than a government programme, I believe that all stakeholders in the infrastructure investment area of ASGISA, like you as members of the AMEU, should associate yourselves fully with this initiative, as ECSA is in fact doing. As indicated in the Medium Term Budget Policy Statement in late 2005, government and public enterprise investment expenditure for the period April 2005 to March 2008 is planned to be in the region of about R370-billion. Of this amount about 40% will be spent by public enterprises, mostly Eskom (R84-billion) and Transnet (R47-billion), and mostly on power generation, power distribution, rail transport, harbours and an oil pipeline. The general purpose is to improve the availability and reliability of infrastructure services in response to rapidly growing demand. I am sure that you, as members of this esteemed association will also be directly affected by this expansion of activities in your field of engineering at a local level. These are indeed mind-boggling amounts of funding and the challenge to the engineering profession is to respond by making use of the current pool of trained engineering practitioners, to properly train and mentor young graduates and diplomates, and to lure more prospective young practitioners with the requisite mathematics and science grades to the profession.

Having said this I now want to turn to the question why voluntary associations like AMEU and employers in general should align themselves with a professional body like ECSA. Firstly, apart from the peremptory nature of the Engineering Profession Act, 2000, ECSA's motivation for promoting alignment with employers of engineering professionals, can be summed up as follows:

- ECSA is the official standards generating body in engineering (in the higher education band) in South Africa, and at the same time, through its Engineering Standards Generating Body (ESGB), fulfils this function on behalf of SAQA.
- ECSA has developed a relationship with various Sector Education and Training Authorities (Setas) in order to facilitate alignment and integration of education, training and professional development under the Skills Development Act.
- ECSA has legal responsibility to accredit engineering programmes offered by educational institutions in South Africa. At the same time ECSA performs this activity as a functionary of the Higher Education Council, which means that ECSA's accreditation outcomes are recognised as a "national" outcome.
- ECSA represents South Africa as an official signatory to a variety of mutual recognition agreements, thus ensuring international equivalency of South Africa's educational and professional standards.
- ECSA signed a memorandum of understanding with NEPAD, and will assist

the engineering professions in Africa to achieve international recognition, should such assistance be required.

- ECSA represents South Africa on the World Federation of Engineering Organisations (WFEO) and is actively participating in WFEO's capacity building initiatives in Africa.

Secondly we believe that it is a win-win relationship.

Being well positioned to serve the interests of the country, the public and (probably just as important) the practising professionals themselves, it will certainly be a win-win situation for ECSA, VAs and employers to co-operate more closely as we address national challenges. However, more specifically, we can only win all round because:

- ECSA's impact is beneficial to the maintenance of standards of engineering education, training, professional development and professional conduct. Employers are direct beneficiaries of ECSA's involvement.
- ECSA's activities have a direct and beneficial impact on, and are aligned with, national initiatives, i.e. the National Qualifications Framework (SAQA), the Higher Education Quality Committee (Accreditation), skills development in the higher education band (National Skills Authority and Seta's), as well as the ASGISA and JIPSA initiative as already indicated. Further
- ECSA relies on the support from VAs, employers and professionals to fulfil its statutory functions and responsibilities. Without this support, the interests of society, and the country as a whole, cannot be served as well as it should.

Thirdly, we believe that it is most important to note that, in contrast to the previous government, the built environment legislation of 2000 reflects a very strong and committed political will on the part of the current government to promote public health and safety and the environment by ensuring professional accountability among all professionals active in the built environment.

We all know by now that the Engineering Profession Act was only enacted following years of deliberations in the "Forum for the Professions in the Built Environment" which was initiated by the then Minister of Public Works, Jeff Radebe. The idea of this forum was to assess the extent to which the professions have served the interests of the country in the past and whether they are still relevant in meeting the needs of the new South Africa. Consensus reached in the forum was that the statutory control of the built environment professions in South Africa was still essential and this led to the decision to proceed with preparing new legislation to regulate the professions.

The policy document that emerged from this process states (among others): "It is the opinion of the ministry that, in order to meet the objective of upholding standards through registration, all persons who are eligible for registration and who practise their vocation, whether self employed or salaried, should be obliged to register."

The forum identified a number of key issues which would reflect government policy and intention. An important element of these issues stemmed from the belief that there should be a much stronger drive to protect the public against bad professional (engineering) practices and that somebody should be held accountable for that. The government believes that the professional councils should be held accountable for unprofessional practices of the practitioners - improper conduct - and that the individual professionals should be held accountable by the councils for their conduct.

Having said this, I think it is imperative that we take note of what is determined by Sections 18 and 26 of the Act.

Sections 18(2) and 18(3) of the Engineering Profession Act:

- Prohibits a person who is not registered in a category from practising in that category of registration; and
- Permits a person registered in a category to consult in that category.

Section 18(4)(c) of the Act further requires that a candidate in a category must perform work in the engineering profession under the supervision and control of a professional in a category as prescribed. Consequently, a candidate may not consult.

Section 26(3) of the Act prohibits a person who is not registered in terms of the Act from performing any kind of work identified for any category of registered persons. The Act in Section 26(4) allows one exception to this prohibition. The unregistered person may work under the supervision and control of a registered person who must take the responsibility for the work. Accordingly, a registered person taking responsibility for the work of unregistered persons must do so from a fully informed position, must exert active supervision and control and must approve all critical decisions. It would be unethical for the registered person simply to accept a recommendation from the unregistered person.

Only when work has been identified in terms of section 26(1) and section 20 of the Council for the Built Environment Act, will section 26(3)(b) be enforceable.

It is important to note that any contravention of Sections 26(3)(b) and 18(2) of the Act, will, in principle, result in ECSA lodging a criminal charge against the person contravening the sections. ECSA will most likely not proactively police possible contraventions, but will rely on the public and/or practising professionals to report such contraventions.

The latest news on progress in this regard is that the framework document on the Identification of Engineering Work was approved by council in November 2005 and that the final draft of the regulations was approved by Council on 17 August 2006. The report and regulations have already been forwarded to the Council for the Built Environment for liaison with the Competition Commission in terms of Section 20 of the Council for the Built Environment Act, 2000. It is hoped that this process will be completed within the next 12 months. Acceptance of the regulations will result in all engineering practitioners who perform identified engineering work, having to register with ECSA. The so-called compulsory registration era which we will now enter into will level the playing fields between unregistered and registered engineering practitioners. Registered professionals may be pleased to note that unregistered practitioners would also have to come on board and would also have to undertake CPD activities in order to keep their professional registration intact.

I now want to turn to the renewal of registration through the formal system of CPD - another important provision in terms of the 2000 Act which ECSA is obliged to implement. I think most of us will be aware that the system was formally implemented as from January 2006.

Time does not allow me to go into detail about the different credits that may be earned in terms of the three categories of CPD activities. I therefore want to emphasise firstly that the point of departure of the ECSA committee that designed the CPD system, was that the system must be as user friendly as possible and that cost to the individual practitioner to obtain the necessary CPD credits, should be as low as possible.

As we know CPD consists of two dimensions, namely the technical, discipline-specific body-of-knowledge and other (e.g. managerial, finance, IT, specific skills such as negotiating, presentations, etc.). In each of these there are two aspects, namely the acquiring of existing knowledge and the expansion of the body of knowledge.

In terms of the existing body of knowledge, whether technical or other, it provides for a relatively easy assessment and accreditation of course work, seminars, etc. In the process of professional development we see the following:

- Formal courses presented by accredited tertiary institutions and VAs, which are all validated;
- Activities presented by private providers which have been validated by VAs.

In the expansion of knowledge one can distinguish between own unique contributions to technical knowledge in the form of new paradigms, techniques, etc. and the expansion of knowledge through remaining current with new developments and subsequent application and modification. Here we see the following:

- Original research and development;
- Conferences, seminars and other VA activities in which the above are evident

It is therefore imperative for VAs to keep this in mind when validating category 1 activities. As we have indicated in the past, CPD is not just another academic exercise. However, an element of educational development must be part of the CPD requirements, but it is not necessary to over-emphasise this one category of CPD activity above all else.

In conclusion, it is clear that your agenda for this convention covers a wide variety of technical subjects, and your theme of "Electricity Service Delivery – the Challenge", indeed raises more aspects in the field of service delivery than can be covered in the span of three days. We know that in the recent years there has been a growing concern about the quality of electrical supply and the apparent deterioration in services offered by local utilities and municipalities. Amongst these concerns is the forecast that the SA peak electrical power demand will exceed the available generating capacity, resulting in regular peak period outages. I am aware that the National Energy Regulator and Eskom have been working on corrective action, which includes the return to service of several older power stations, the addition of peak load power stations and the introduction of new fossil fuel power stations. In addition, Eskom and the NER are considering alternative solutions such as the re-introduction of mandatory load shedding and demand side management. As you are no doubt aware the demand side management (DSM) initiative is a process whereby Eskom identifies and implements energy savings and load shifting projects, beyond the customer's meter point in the factory or facility, in such a manner as to provide sustained energy savings and/or a sustained reduction in the peak load of the customer's facility. The objective of such projects is to save national energy resources and to assist consumers to reduce their energy costs by improving energy efficiency and improving the load factor. Power saved through DSM should be significantly cheaper and quicker to implement than power provided through a new power station. The Eskom DSM initiative is a unique opportunity for business and industry to benefit through participation in energy efficiency and load management projects. Natural resources are conserved and carbon gases are reduced. Hopefully your convention will also during the next three days provide related solutions to challenging problems on electricity service delivery in our country.

Mr. Chairman, with these few ideas on ECSA's support to ASGISA and JIPSA, the envisaged compulsory registration of all engineering practitioners and the renewal of registration through CPD, I hope you will have some food for thought to share with your members in the days ahead. I wish you well in your further deliberations over the next three days.

In closing - according to a recent study released last month by two prominent Harvard University economists - South Africa is praised as a model emerging economy and that we are living in South Africa's 'age of hope'. However, given our high levels of unemployment (between 26% and 38%) and our current account deficit of approximately 6%, is our age of hope sustainable? As our corporate social responsibility I invite all of you to advance on all fronts the fight against marginalisation and poverty. Δ

The supply of electric power in Tanzania

by Adriaan van der Merwe and William Mhando, Tanesco

This paper gives an overview of the generation, transmission and distribution sector in the mainland of Tanzania and highlights some of the challenges and problems the utility faces. It briefly refers to the regional interaction within eastern Africa and possible energy pool arrangements. It gives a post-delisting visionary roadmap for the privatisation of Tanesco while retaining its status as a vertically integrated monopoly, meeting the growth imperatives for the government of Tanzania.

Tanzania Electric Supply Company (Tanesco) was established in 1931 and was the major power company operating in Tanganyika. It become the national power utility in 1964, wholly owned by government and has since then been responsible for power generation, transmission, distribution and electricity sales on the mainland of Tanzania. It also provides bulk power supply to State Fuel and Power Corporation (SFPC) in Zanzibar by means of a submarine cable. Plans are also under way to supply the island of Pemba in the same way in 2007.

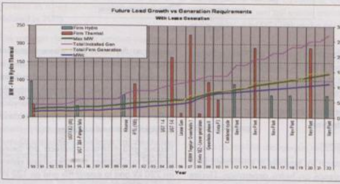

Fig. 1: Growth estimates for Tanzania

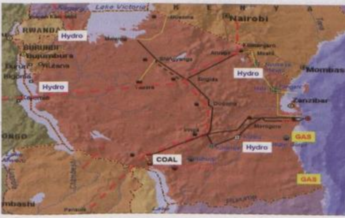

Fig. 2: Strategic placement of Tanzania for energy market and trading.

Tanesco has its headquarters in Dar es Salaam and 23 regional and various district offices in mainland Tanzania.

Overview of the power sector

In general, Tanzanians depend largely on biomass energy. Energy provided by charcoal and firewood account for over 90% of total energy consumption in the country and access to electricity is about only 10%.

Petroleum and electric energy account for 9%. Other energy sources like coal, solar and wind account for the remaining 1%. This pattern of energy consumption shows that Tanzania has not yet developed commercial sources of energy to meet the country's demand.

Tanzania has generous domestic sources of power generation such as hydro, natural gas, biomass, and coal. Various efforts are in hand to develop resources such as natural gas, coal and hydropower.

Coal

Coal reserves in Tanzania are estimated at 1 200-million tons in the western and south-western parts of the country. Coal sites include Kiwira and Katewaka/Mchuchuma. Although this resource is available in large quantities, its exploitation and utilisation is very low, due to lack of economies of scale and available infrastructure. Nevertheless, the small quantity of coal that is mined by a private company at Kiwira is used for the generation of electricity which is sold to Tanesco.

Natural gas

Natural gas at Songo Songo island was confirmed in 1977 and recently, the reserve audit puts the gas reserve amount to be 736-billion cubic feet (BCF). In 2002, investors in Songo Songo gas, Songas, started construction of gas processing facilities and a pipeline for the transportation of gas from Songo Songo island off the south-eastern coast of Tanzania by means of a gas pipeline of 126 km to Dar es Salaam. As at 2005, Songas was capable of generating a total of 192 MW, feeding the national grid.

Natural gas was also confirmed in Mnazi Bay and Tanesco has entered into a PPA to supply generation to the south western part of the country near the Mozambique border. This source is expected to come into operation in 2007.

Tanesco is in the process of acquiring 142 MW of gas fired generation at Ubungo and Tegeta in Dar es Salaam. Due to the bad hydrology the company is also in the process of leasing/renting gas generation of 140 MW at Ubungo to be operational by the end of 2006. This is to alleviate the current power rationing in the country.

Hydro

The total hydro potential available in the country is estimated to be at 3800 MW with annual firm energy capability of about 20 000 GWh. However, of this only about 15% has been exploited.

Installed power capacity

The total installed capacity in Tanzania grew from 612 MW in 1999 to 897 MW in 2005, representing 6,6% annual growth.

The growth of the electricity sub-sector showed a high increase due to IPPs' installed generating sets at Ubungo and Tegeta areas in Dar es Salaam. As at January 2006, the major IPPs contribute about 33% to the entire

River system/power plant	MW
Great Ruaha hydro system	
- Mtera	80
- Kidatu	200
Pangani hydro system	
- NYM	8
- Hale	21
- Pangani Falls	68
Lower Kihansi Hydro	180
Grid diesel - plants	40
Songas	200
IPTL	100
Total installed capacity	897

national grid's generating capacity. The growth trend and anticipated future demand is shown in Fig. 1.

Imperatives for eastern Africa

Various initiatives such as the Southern African Power Pool (SAPP), the Nile Basin Initiative and others, identified the need for regional co-operation in the energy field and cross-border trading.

For such an energy market to be operational, an adequate energy carrier (transmission system) linking the various participants and traders is essential.

It is not the purpose of this paper to reflect on these developments but only to point out the strategic role Tanzania ought to play with its strategic energy resources in hydro, coal and gas as well as its geographical placement in this sector, as can be seen from Fig. 2.

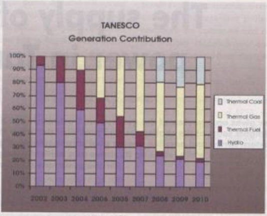

Fig. 3: Planned future generation mix.

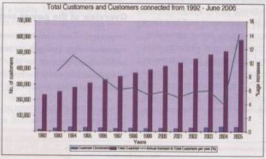

Fig 4: Customer growth

From the above it is clear that these initiatives will have a specific bearing on power sector reform in Tanzania and the restructuring of Tanesco.

Generation, transmission and distribution

Generation

Generation in Tanzania is dominated by a dependence on hydro generation. During times of insufficient rain the installed capacity is adequate to supply the total needs of the country. Only recently (2005) the generation resources were significantly strengthened by the adding of thermal energy from Songas. In terms of the long-term forecasts and planning it is estimated to change this generation mix and to diversify the resources to include coal, gas, hydro and others to supply national demand. This change is depicted in Fig. 3.

Transmission

Due to the size of the country Tanesco has an extensive transmission system consisting of 2 986 km of 220 kV, 1 971 km of 132 kV and 824 km of 66 kV lines. As can be seen in Fig 2, power needs to be conveyed over a large distance from the main resources in the south (hydro) and the east (gas) of the country to the north west where important mining customers are situated. Demand is scattered and relatively low in other area besides Arusha, Moshi, Kilimanjaro hub(north) and the Mwanza hub (near Lake Tanganyika) while Dar es Salaam currently takes about 60% of the national supply.

Various grid extension projects are being planned to strengthen the national grid system on 220 kV and to extend the grid on 132 kV to electrify remote areas.

The focus of the grid strengthening will be to start the process of creating an eastern African grid linking Zambia and Kenya for future pool trading. Inter-governmental agreements have been entered into between the relevant governments for this purpose.

Distribution

Distribution services are rendered via 23 regional offices and various district offices. Of the 4800 employees about 4000 are situated within the distribution division, servicing some 580 000 customers across the country on the customer book.

The majority of customers, namely 59%, are in Dar es Salaam which is the only area with reasonable access to electricity. Distribution is responsible for the regional retail services of collection, billing, Luku (prepaid) and customer services.

Collections are currently on 97% of billing and yield a cash turnover of Tsh 300-bn per annum. Customer growth and electrification was good the last couple of years but more focus will have to be on the right customer mix to ensure financial sustainability of the utility in the future. Focus will have to be on mining customers and other commercial customers.

Tariffs compare very favourably with the neighbouring countries of Kenya and Uganda but are currently not fully reflective of cost of supply. Applications have been lodged with the national regulator for tariff increases.

Vision for Tanesco

After listing for privatisation

Tanesco was listed for privatisation in 1997 and a specific process was followed to prepare Tanesco for sell-off. For this purpose the GOT entered into a management contract with NETGroup Solutions (SA) in 2002. Utility performance and sustainability was achieved through various business improvements and turnaround activities. Due to this and to keep Tanesco as a vertical-integrated utility, it was delisted in 2005.

The strategic visioning for Tanesco ought now to be to ensure service delivery for economic growth and the eventual maximising of returns for shareholders.

Challenges facing Tanesco

The utility currently is engaged in a rolling power rationing programme mainly due to the hydrology situation. The legacy of structuring the business for privatisation meant that various normal long term utility processes and initiatives were delayed or postponed in anticipation of the alienation of the utility.

The main challenges can be summarised as follows:

- The full national demand cannot be met
- Heavy dependency on hydro generation
- Inability to supply new customers quickly enough
- Inadequate business systems and processes to support the business plan
- Skills needed for growing the business

The structuring of the utility should be focused to ensure that the said challenges are met. After delisting, Tanesco is currently in a phase of stabilisation and reorganisation to meet the envisaged utility growth of some 15% and

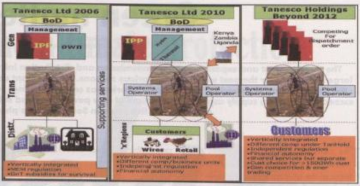

Fig. 5: Envisaged reform changes and transformations as per the business plan.

$1,5-billion investment till 2012 that will increase the customer base to about 1,2-million customers.

This will provide some 25% access to electricity in Tanzania. The greatest concentration will be in the urban areas around the major cities but with a dedicated effort to bring electricity from both grid and off grid supplies to rural customers. An important feature of growing the business will be to supply additional industrial and mining customers. Growing the business this way will ensure annual sales in the order of 6 000 GWh and a demand of 900 MW by 2012.

To achieve this, power sector reform and organisational change are necessary imperatives to provide the platforms for growth and delivery.

Power sector reform and utility restructuring

"If you do not like change you're going to like irrelevance even less."

This wisdom from Tom Peters in his book "Re-Imagine" is surely applicable in the following envisaged changes.

As a vertical monopoly, Tanesco's regulation was under MEM until EWURA was operationalised in the second half of 2006. Various influences are impacting on Tanesco and it is clear that there will be change in all the sections of the business as depicted in Fig. 5. It is most likely that these challenges will come gradually in the business and will challenge its normal operation and structure.

The current domination of the IPPs in thermal generation will be broken with Tanesco's own thermal generation and the adding of short term lease gas generation during 2006 and 2007. During this growth phase the energy market will probably be developed to enhance trading with neighbouring countries. It is also foreseen that the utility will have to structure its distribution division into "wires" and "retail" to cater for the additional customer numbers.

Conclusion

The challenge for Tanesco in the next five years is to service the growing need of customers in order to provide the stimulus for economic growth in the country while reforming the business in a changing power sector environment.

It is anticipated that Tanesco will be an organisation in transformation and change until at least 2010. It will be of essence to follow and execute the various strategic intents referred to in this paper to ensure business success and to meet the economic growth envisage by GOT. Δ

Green matters

by RE Zietsman, Geopower

The development and expansion of the transmission and distribution infrastructure in South Africa was by and large deferred over the past years, due to various reasons. The resultant delay in the investment and expansion of the infrastructure in municipal and Eskom networks has seen many lines reaching their capacity and substations exceeding their firm supply capacity. The volume of new power lines and substations that are planned for execution over the next five years in South Africa is phenomenal.

The construction of power lines and substations are however regulated activities in terms of the environmental legislation and its regulations. Formal authorisation is required for each line that is to be erected and for each substation that is to be constructed. Past experience has shown that such authorisations can take several months to obtain. Fortunately with the new regulations that came into effect in July 2006, time limits have been stipulated for the review and granting of authorisations. The overall time period required for an application can however exceed the guideline period if the application is not complete or if additional investigations are requested.

The purpose of this paper is to inform electrical engineers and electricity utilities of the environmental legislation that exists, in order that they can ensure that the infrastructure that they have constructed and plan to construct, is in compliance with the Act and its regulations. More importantly the purpose of this paper is to mobilise utilities to commence with the relevant applications for environmental authorisation, as construction of substations and power lines may not commence without such authorisation, which takes on average approximately six months to obtain. A six month delay in the upgrading or establishment of infrastructure that is crucial to the utility's service delivery, is significant and can have potentially catastrophic results.

Environmental legislation and governance

King Code on Corporate Governance II – 2002

The King Code on Corporate Governance II – 2002 establishes directors of a business as the focal point of the corporate governance system, with ultimate accountability and responsibility for the performance and affairs of a business. Although management committees with formally determined terms of reference, roles and functions constitute an important element of the process, the delegation of authority to any other committee does not in any way mitigate or dissipate the discharge of the directors of their duties and responsibilities. Every management team should also adopt a formal charter describing its roles and responsibilities, which should be disclosed in the annual report.

The directors of a utility must therefore ensure that the following environmentally related responsibilities are implemented in order to ensure compliance with the King Code:

- Determining the utility's objectives and values including the utility's environmental policy;
- Determining the strategy to achieve the utility's objectives and to implement its values;
- Ensuring that effective and practical environmental procedures and practices are in place that protect the utility's assets and reputation;
- Monitoring and evaluating the implementation of environmental related strategies, policies, management performance criteria and business plans;
- Ensuring that the utility complies with all relevant environmental laws, regulations and codes of best business practice;
- Identifying key environmental related risk areas at an early stage in order to develop the relevant key performance indicators of the utility to good environmental and social responsibility;
- Regularly assessing the environmental impacts and the performance and effectiveness of the utility, including its directors, to implement acceptable environmental impact mitigation measures.

The Constitution of the Republic of South Africa – Act 108 of 1996

Everyone has the right to an environment that is not harmful to their health or well-being and everyone has the right to have the environment protected for the benefit of present and future generations, through responsible legislative and other measures that prevent pollution and ecological degradation, promote conservation and secure ecologically sustainable development and the use of natural resources, while promoting justifiable economic and social development.

Should the utility's actions potentially result in an environment that is harmful to the health or well-being of the public, it is advisable to conduct a full environmental impact assessment.

The Environmental Conservation Act (ECA) – Act 73 of 1989

The Environmental Conservation Act, Act 73 of 1989 was the first Act to introduce the requirement to undertake an environmental impact assessment (EIA) in South Africa.

Section 21 of the ECA provides that the Minister of Environmental Affairs and Tourism may, by notice in the Government Gazette, identify certain listed activities, which in his opinion may have a detrimental effect on the environment. The identification takes place after consultation with certain other ministers. The activities that were listed include land use and transformation, water use and disposal, electricity generation and distribution, resource renewal to name a few.

Regulations giving effect to the EIA provisions under the Environmental Conservation Act, Government Notice: Regulation 1182 (R1182) were promulgated on 5 September 1997. Regulation 1182 identified certain activities as activities that were considered substantially detrimental to the environment. These regulations were amended by Government Notice: Regulation 670 of 7 May 2002. These regulations have since been replaced by new regulations that were passed by the minister in April 2006, and came into effect on 1 July 2006.

The National Environmental Management Act (NEMA) Act 107 of 1998

The principles of NEMA include that decisions must be taken in an open and transparent manner and access to information must be provided in accordance with the law.

In April 2006 the Minister of Environmental Affairs and Tourism passed regulations in terms of Chapter 5 of the National Environmental Management Act. These regulations replace the environmental impact assessment (EIA) regulations that were promulgated in terms of the Environmental Conservation Act and introduce new provisions regarding environmental management frameworks.

The two regulations R386 and R387 of 2006, make provision for the undertaking of a basic assessment and a scoping/EIA respectively.

National Environmental Management Amendment Act, Act 8 of 2004

Section 24(1) of NEMA, Act 8 of 2004, (which Act came into effect on 7 January 2005) provides that in order to give effect to the general objectives of integrated environmental management, the potential impact on the environment of listed activities must be considered, investigated, assessed and reported to the competent authority charged by this act with granting the relevant environmental authorisation.

The National Water Act, Act 36 of 1998 – GN R 704 of 4 June 1999

Occupational Health and Safety Act, Act 85 of 1993 – major hazard installation regulations – GN R692 of 30 July 2001

Environmental authorisation

Infrastructure for electricity that requires authorisation

The former regulation defined the construction, erection or upgrading of facilities for commercial electricity generation with an output of at least 10 MW and infrastructure for bulk supply as listed activities. This definition was clear in terms of generation but was open to interpretation in terms of the definition of the term "bulk supply". The term "upgrading" was previously defined as the expansion beyond its existing size, volume or capacity of an existing facility, installation or other activity, but did not include regular or routine maintenance and the replacement of inefficient or old plant, where such did not have an increased detrimental effect on the environment.

The current regulations by contrast clearly distinguish between activities that have either a potentially low or a potentially high risk of impact on the environment due to their inherent nature. Activities that have been identified as having a relatively low impact on the environment are categorised in the schedule of Regulation 386 and are subject to a basic assessment process for environmental authorisation. Activities that have been identified as having a relatively high impact on the environment are categorised in the schedule of Regulation 387 and are subject to a comprehensive environmental assessment process which includes scoping and an EIA process for environmental authorisation. The listed and specified activities relating to the construction of infrastructure for electricity is provided in this paper.

The following activities that are directly related to electricity require a basic assessment process to be followed in order to obtain authorisation:

- The construction of facilities or infrastructure including associated structures or infrastructure, for the generation of electricity where the output is more than 10 MW but less than 20 MW;
- The construction of facilities or infrastructure, including associated structures or infrastructure, for the transmission and distribution of electricity above ground with a capacity of more than 33 kV and less than 120 kV.

The following activities that are directly related to electricity require a comprehensive and thorough environmental assessment process, including a scoping and EIA, to be adopted in order to obtain authorisation:

- The construction of facilities or infrastructure including associated structures or infrastructure, for the generation of electricity where the output is 20 MW or more; or the elements of the facility cover a combined area in excess of 1 hectare.
- The construction of facilities or infrastructure, including associated structures or infrastructure, for the transmission and distribution of above ground electricity with a capacity of 120 kV or more.

Interpretation

Electrical engineers have a tendency to be pedantic and would perhaps prefer more detailed and descriptive definitions. The following interpretation of the foregoing definitions are perhaps in order:

(a) Power lines

The definition in terms of power lines is well defined except that the term "capacity" should be understood as "voltage level". Power lines are listed as activity 1(l) in the schedule of the regulations.

No authorisation is required for the construction of 11 kV, 22 kV or 33 kV power lines unless they cross a wetland or other environmentally sensitive area.

In terms of Regulation 386, a basic assessment process leading to authorisation is required for the construction of 44 kV, 66 kV and 88 kV power lines.

In terms of Regulation 387, a scoping/EIA process leading to authorisation is required for the construction of 132 kV, 275 kV, 400 kV and 765 kV power lines.

The foregoing criteria apply to the voltage level of the design of the power line irrespective of the actual voltage level at which the power line may be operated. There are instances where a power line will initially be operated at a lower voltage until certain infrastructure is provided. The fact that a 132 kV power line will perhaps initially be operated at 33 kV does not exempt it from a scoping/EIA authorisation prior to construction.

The regulations do not distinguish between distribution power lines within a city or town; and transmission lines that interlink power stations with main transmission stations (MTS) and the in-feed stations at the outskirts of a city or town. The voltage levels of distribution systems within a city or town in South Africa are typically confined to 66 kV, 88 kV and 132 kV although 275 kV distribution systems do exist. The voltage levels of transmission systems in South Africa are restricted to 132 kV, 275 kV, 400 kV and 765 kV. The standard transmission voltage levels for power lines are included in Regulation 387 and it can therefore be interpreted that a comprehensive assessment process (scoping & EIA) is required for all transmission lines. This makes sense as transmission lines are characterised by their relatively long length and in many instances their route crosses undisturbed environmental tracts of land.

The environmental regulations do not prescribe any mandatory servitude width for power lines and the widths as provided in the relevant NRS specifications are generally accepted as best practice.

(b) Substations

The criteria in terms of substations are perhaps not as well defined in the regulations as those of power lines. The listed activities emphasise generation which to an electrical engineer relates to the production of electrical energy at a power station. Electricity is created at a power station and is distributed at a substation where in most cases its voltage level is transformed. The description of the activity states: "The construction of facilities or infrastructure, including associated structures or infrastructure for the generation of electricity." The term "construction" in terms of the regulations means the building, erection or expansion of a facility, structure or infrastructure that is necessary for the undertaking of an activity, but excludes any modification, alteration or upgrading of such facility, structure or infrastructure that does not result in a change to the nature of the activity being undertaken or an increase in the production, storage or transportation capacity of that facility, structure or infrastructure. The terms "associated structures or infrastructure" in terms of the regulations means any building or infrastructure that is necessary for the functioning of a facility or activity or that is used for an ancillary service or use from the facility. A substation can be interpreted as being an associated infrastructure or an ancillary service or use from a power station (generation).

Power lines are normally connected to a substation that transforms the voltage level from a primary voltage level to a secondary voltage level. The fact that no authorisation is required for power lines with a voltage level of 33 kV and less, may imply that substations with a voltage level not exceeding 33 kV should also be exempt from an environmental authorisation, providing that they are not proposed on environmentally sensitive areas.

A safe interpretation of Clause 1 of the Schedule of Regulations 386 and 387 is to replace the terms "generation of electricity" with "provision of electricity". Substations with an installed transformer capacity of 20 MVA or more, or a footprint area in excess of 1 hectare are subject to a scoping/EIA process for environmental authorisation, while substations with an installed transformer capacity of less than 20 MVA are subject to a basic assessment evaluation.

(c) Power stations

Power stations are clearly defined as the first listed activity, activity 1(a) in the schedule of the regulations. Provision is also made for nuclear reactors.

(d) Underground cables

The regulations exclude underground cable installations, irrespective of the voltage level, as they refer only to the distribution of electricity above ground. Authorisations in terms of cable installations are not required unless the cables are to be laid through an environmentally sensitive area such as a wetland. In such instances the authority will typically request confirmation that there are no alternate supply options, even if such supply options need to be negotiated and obtained from an adjacent licensed electricity supply authority.

Application

The starting point in obtaining the environmental authorisation for an "activity" such as a substation or a power line is the completion of an application. The application is made using an official application form which is obtainable from the relevant environmental authority. Documentation in support of an application is largely dependent on the assessment procedure that is defined for the specific activity, and includes a report.

All applications for environmental authorisation must be supported by an assessment. The regulations provide for two types of assessment procedures, i.e. the basic assessment process and the scoping and EIA process. The purpose of a basic assessment is to provide a mechanism for the complete but concise assessment of activities. A scoping and environmental impact assessment process is reserved for activities which have the potential to result in significant impacts which are complex to assess. Scoping and environmental impact assessment accordingly provides a mechanism for the comprehensive assessment of activities that are likely to have more significant environmental impacts.

The application is normally prepared by an environmental assessment practitioner "EAP" who is appointed by the electricity utility to manage the application for the environmental authorisation of the works. The EAP must determine which of the two procedures is applicable for the application. It is advisable to discuss the type of procedure with the authority, especially in the case of substations.

The relevant environmental authority is hereafter obliged to acknowledge receipt of the application or reject the application if it is found not to be in order, in writing within 14 days.

If the applicant intends undertaking more than one activity of the same type (i.e. 132/11 kV substation) at different locations in the same province, separate applications in respect of the different locations must be submitted. The competent authority may however, at the written request of the applicant, grant permission for the submission of a single application in respect of all the activities.

EAP

An EAP is a person who manages an application for environmental authorisation on behalf of the applicant. The electricity utility must ensure that the EAP to be appointed complies with regulations 18(a) and (b) and must provide the EAP with access to all information at its disposal regarding the application, whether or not such information is favourable to the electricity utility.

The EAP appointed must be:

- Independent
- Possess the necessary expertise
- Perform the work in an objective manner
- Comply with the Act and registration
- Disclose information that may influence the decision

Apart from being competent and independent, the EAP must also undertake the work objectively – even if this results in findings that are unfavourable to the utility. In view of this, the EAP must disclose all information that has the potential to influence a decision for the authorisation of the application. The EAP is also responsible for ensuring that a public participation process is undertaken in accordance with the requirements of the regulations.

The utility will need to provide the EAP with a detailed scope of the work involved as well as a detailed description of the works. This aspect should not be underestimated and if the utility has limited personnel resources it may be advisable to appoint an electrical engineer to assist the EAP with the application.

Listed and specified activities

Schedules

The two Regulations 386 and 387 of 2006 each contain a schedule. Each of the schedules lists the various listed activities as categorised according to the applicable assessment procedure and defines the activity number, description and identification of the competent authority per activity. The scope of the relevant listed activities pertaining to electricity are collectively summarised in paragraph 4.3.

The schedule of Regulation 386 lists the activities identified in terms of the Act, which may not commence without environmental authorisation in respect of which the investigation, assessment and communication of potential impact of activities must follow the procedure described in Regulations 22 to 26 for a basic assessment.

The schedule of Regulation 387 lists the activities identified in terms of the Act, which may not commence without environmental authorisation in respect of which the investigation, assessment and communication of potential impact of activities must follow the procedure described in Regulations 27 to 36 for a scoping and EIA.

Definitions applicable to regulations

"associated structures or infrastructure" means any building or infrastructure that is necessary for the functioning of a facility or activity or that is used for an ancillary service or use from the facility;

"construction" means the building, erection or expansion of a facility, structure or infrastructure that is necessary for the undertaking of an activity, but excludes any modification, alteration or upgrading of such facility, structure or infrastructure that does not result in a change to the nature of the activity being undertaken or an increase in the production, storage or transportation capacity of that facility, structure or infrastructure;

"expansion" means the modification, extension or alteration of a facility, structure or infrastructure at which an activity takes place in such a manner that the production, treatment, storage or capacity of the facility is increased;

"floodplain" means a discernable flat landscape feature next to a river or stream that was created by weathering and sedimentation over time;

"phased development" means an activity that is developed in phases over time on the same or adjacent properties to create a single or linked entity through interconnected internal vehicular or pedestrian circulation, sharing of infrastructure, or the continuum of design,

style or concept by the same proponent of his or her successors.

"the Act" means the National Environmental Management Act, 1998 (Act No. 107 of 1998); and

"the Regulations" means the Environmental Impact Assessment Regulations, 2006.

"the Schedule" means activities identified in terms of section 24(2)(a) and (d) of the act, which may not commence without environmental authorisation from the competent authority and in respect of which the investigation, assessment and communication of potential impact of activities must follow the procedure as described in regulations 22 to 26 of the environmental impact assessment regulations, 2006, promulgated in terms of section 24(5) of the act.

Relevant listed activities

(a) Generation of electricity (Listed Activity 1(a))

The construction of facilities or infrastructure including associated structures or infrastructure for the generation of electricity where the electricity output exceeds 10 MW or where the elements of the facility cover a combined area in excess of one hectare.

(b) Transmission & distribution of electricity above ground (Listed Activity 1(l))

The construction of facilities or infrastructure, including associated structures or infrastructure, for the transmission and distribution of electricity above ground with a capacity of more than 33 kV.

(c) Activities in the 1:10 flood line (Listed Activity 1(m))

The construction of facilities or infrastructure including associated structures or infrastructure for any purpose in the one-in-ten year flood line of a river or stream, or within 32 m from the bank of a river or stream where the flood line is unknown, excluding purposes associated with existing residential use, but including: canals; channels; bridges; dams; and weirs.

(d) Activities requiring dredging (Listed Activity 4)

The construction of facilities or infrastructure including associated structures or infrastructure for the dredging, excavation infilling, removal or moving of soil, sand or rock exceeding 5 m³ from a river, tidal lagoon, tidal river, lake, in-stream dam, floodplain or wetland.

(e) Masts (Listed Activity 14)

The construction of facilities or infrastructure including associated structures or infrastructure for the construction of masts of any material or type and of any height, including those used for telecommunication broadcasting and radio transmission, but excluding: masts of 15 m and lower exclusively used by radio amateurs or for lighting purposes; flag poles; and lightning conductor poles.

(f) De-commissioning and re-commissioning (Listed Activities 23 & 24)

The construction of facilities or infrastructure including associated structures or infrastructure for the de-commissioning or re-commissioning of existing facilities or infrastructure, other than facilities or infrastructure that commenced under an environmental authorisation issued in terms of the environmental impact assessment regulations, 2006 made under section 24(5) of the Act and published in Government Notice No. R. 385 of 2006 for:

- electricity generation;
- nuclear reactors and storage of nuclear fuel;
- industrial activities where the facility or the land on which it is located is contaminated or has the potential to be contaminated by any material which may place a restriction on the potential to re-use the site for a different purpose;
- the disposal of waste;
- the treatment of effluent, wastewater and sewage with an annual throughput capacity of 15 000 m³ or more;
- the recycling, handling, temporary storage or treatment of general waste with a daily throughput capacity of 30 m³ or more; or
- the recycling, handling, temporary storage or treatment of hazardous waste.

Authorisation process

Basic assessment

The basic assessment process includes all the aspects required by NEMA but in a way that facilitates a concise process. This is mainly achieved by indicating what information the competent authority requires in the regulations, thereby limiting the number of interactions between the EAP and the competent authority.

This means that the competent authority is presented with all the appropriate documentation at the time it receives the application since the EAP would already have conducted the public participation process and compiled a basic assessment report containing the information specified in the regulations. The EAP must timeously notify the competent authority of the intention to submit an application because the public participation process and assessment will take place prior to the submission of the application.

If the basic assessment report is accepted, the competent authority will consider the contents of the basic assessment report, including any attachments, and make a decision to:

- Grant authorisation in respect of all or part of the application;
- Refuse authorisation in respect of all or part of the application;
- Request further information or investigation;
- Refer the application to a scoping process where substantial additional investigations or assessments are required in order to make a decision.

A request for further investigation can include a request for further public participation, a specialised study, a specialised process or consideration of alternatives. In such a case a revised basic assessment report or supplementary document must be compiled and submitted to the competent authority as well as be made available to interested and affected parties.

Scoping/EIA

The scoping and EIA process involves a more complex and intensive assessment of the potential impact of an activity. The process takes place in three distinct phases, namely submission of an application form, scoping and the EIA.

Where an application for environmental authorisation needs to be supported by a scoping and an EIA process, an application form must be completed and submitted to the competent authority before that scoping may commence. The applicant is entitled to a pre-scoping consultation with the competent authority before conducting the scoping.

The objective of scoping is to establish the "scope" of the EIA that will be conducted in respect of the activity for which authorisation is applied for, such as a 132 kV power line. The focus during scoping is: to identify and determine issues; potential impacts; and potential alternatives.

Public participation is a key element of scoping. The scoping process culminates in the compilation of a scoping report. The minimum requirements of a scoping report are set out in the regulations and include a plan of study for EIA.

After receiving a scoping report, the competent authority will consider the contents and make a decision to:

- request amendments to the report;
- request further alternatives to be considered;
- reject the scoping report or plan of study; or
- accept the scoping report.

When the competent authority accepts a scoping report and a plan of study for EIA, the EAP must proceed with the EIA. The purpose of the EIA is to:

- address issues that have been raised during the scoping;
- assess alternatives to the proposed activity in a comparative manner;
- assess all identified impacts and determine the significance of each impact; and
- formulate mitigation measures.

Public participation is an essential component of the EIA process. During the EIA process, public participation is conducted in accordance with the plan of study for EIA as opposed to the minimum requirements set out in the Regulations. After the different aspects of the assessment have been undertaken, including any specialised studies and processes, an EIA report is compiled, which must contain at least the information listed in the Regulations, including a draft environmental management plan.

The review and consideration of the EIA report occurs in two phases. In the first phase, the competent authority, after receipt of the EIA report, will take a decision to:

- accept the report;
- request amendments to the report;
- refer the report for specialist review; or
- reject the EIA report.

The second phase occurs after the competent authority has accepted an EIA report, or after receipt of findings of a specialist reviewer. During this phase, the competent authority will take a decision to grant all or part of the application; or refuse all or part of the application.

Environmental legal – compliance

General

The activities and operations of any electricity utility, whether it be Eskom, a municipal electricity department or any one of the proposed Regional Electricity Distributors (REDs) have inherent potentially negative effects on the environment.

These potentially negative effects inevitably create enviro-legal risks to the electricity utility from the date of its establishment.

Furthermore, for an environmental legal risk to arise there need not necessarily be a formal or legal relationship between the electricity utility and the affected party as the provisions of Section 24 of the Constitution provides that everyone has the right to an environment that is not harmful to one's health or well being.

If unmanaged, an enviro-legal risk represents a threat that may prevent an electricity utility from achieving its service delivery objectives and responsibilities, which in turn has a bearing on the utility maintaining its licence with NERSA. In order for an electricity utility to manage its environmental legal risks, it is essential to firstly identify all existing and potential risks by means of a legal compliance audit.

The damage which an unmanaged environmentally related risk can inflict is likely to be wide ranging. It will include not only potential damages claims (financial loss, clean-up and rehabilitation costs and heavy fines) but also several hidden costs such as reputational damage, unwanted media attention etc.

Enviromental legal compliance audit

An enviro-legal compliance audit is an effective means for an electricity utility to identify the environmental related legal risks it runs which may prevent it from achieving its service delivery objectives, and then to consider how it can manage them thereby reducing the likelihood that they will have a serious impact on its operations.

A legal risk is probably best considered as an operational risk and it is therefore prudent for a utility to establish with whom it has legal relationships, i.e. who might invoke their rights against the utility or against whom the utility might need to exercise its rights.

An environmental audit (EA) should as a general rule concentrate on the following two elements:

- Compliance of existing facilities and operations with relevant environmental (including occupational health and safety) laws, regulations and specific institutional requirements; and
- The nature and extent of significantly adverse environmental impacts, including contamination to soils, ground water, and structures as a result of past activities at the existing facilities.

An environmental audit is normally undertaken by an independent consultant having a broad and extensive industrial experience in the relevant areas of the environmental and occupational health and safety legislation.

Environmental management framework

Chapter 8 of the regulations provides that the Minister or MEC may initiate an environmental management framework for an area. EMFs that are adopted by the minister or MEC must be taken into account in the consideration of applications for environmental authorisation in or affecting the areas to which the EMF applies. In practice it is foreseen that EMFs will mostly be joint initiatives between provincial departments and local authorities that act within the mandates of the MECs. It is also likely that the formation of EMFs will in most cases be contracted out to specialists.

EMFs will provide applicants with an early indication of the areas in which it would be potentially appropriate to undertake an activity. Co-operative government is facilitated through the identification of different regulatory responsibilities and recommending mechanisms for addressing the needs of the relevant authorities.

Conclusions

Electricity utilities are bound by the relevant environmental legislation referred to in this paper. In terms of the King code on corporate governance the directors of the utility are ultimately responsible and accountable for the legal compliance of the utility in terms of environmental matters.

Many of the municipal electricity departments as well as Eskom have deferred the establishment and expansion of their transmission and distribution networks. The winter loads imposed on an alarming number of municipal substations have well exceeded the firm supply capacity of these substations. A significant number of power lines have likewise reached their safe supply capacity limits.

In April 2006 the Minister of Environmental Affairs and Tourism passed regulations in terms of the National Environmental Management Act (NEMA) Act 107 of 1998. These regulations replaced the previous regulations in terms of the Environmental Conservation Act on 1 July 2006.

In terms of the new regulations environmental authorisation is required for the construction of all new power lines with a designed voltage level exceeding 33 kV. Authorisation is furthermore required for any increase in the load transfer capacity of any existing power line with a designed voltage level exceeding 33 kV.

In terms of the new regulations, environmental authorisation is required for the construction of all new substations with a primary or secondary voltage level exceeding 33 kV. Authorisation is furthermore required for the reconfiguration or increase in the installed transformer capacity of any existing substation with a primary or secondary voltage level exceeding 33 kV.

Authorisation is not required for the installation of underground electric cables unless these cables are to be installed in an environmentally sensitive area such as a wetland.

An environmental legal compliance audit is an effective means for an electricity utility to identify the environmental related legal risks it runs, that may prevent it from achieving its service delivery objectives, and then to consider how it can manage them thereby reducing the likelihood that they will have a serious impact on its operations.

Way forward

Based on the foregoing the following activities are recommended for any existing or newly established utility:

- Appoint an environmental consultant to perform an environmental legal compliance audit of all the utility's infrastructure, in order to identify any risks that may have arisen due to environmental non-compliance.
- Manage any risks that have been identified in a professional manner, to minimise the impact on the operations of the utility.
- Identify, by means of a desk-top study, which substations will require reconfiguration and expansion in order for the utility to continue to supply the load growth in a safe and reliable manner. Define the scope of work for each of these substations and appoint an environmental consultant to make the necessary application to the appropriate authority for environmental authorisation of the envisaged works.
- Identify the need for all future substations, on an ongoing basis, by means of a master plan study, bearing in mind that a concept master plan study will suffice for this purpose. Elaborate and sophisticated master plan studies have failed many utilities in the past. Identify at least three alternative substation positions. Define the scope of work for each of these substations and appoint an environmental consultant to make the necessary application to the appropriate authority for environmental authorisation of the envisaged works.
- Identify which lines will require to be upgraded or replaced with new lines having an increased load transfer capacity. Determine the need for additional power lines that will be required within the next five years. Establish at least three alternative line routes and define the scope of work for each line and appoint an environmental consultant to make the necessary applications to the appropriate authority for environmental authorisation of the planned lines.
- Present the proposed projects to the environmental representatives of the relevant municipality to obtain their support in the authorisation process.
- Convene a meeting with the relevant authority to present the integrated application.
- Ensure that the utility has a thorough knowledge and understanding of the relevant regulations.
- Ensure that effective and practical environmental procedures and practices are in place to protect the utility's assets and reputation. Δ

The implementation of NRS 048-6

by Baden Chatterton, Eskom

The new NRS 048-6 standard (medium voltage network interruption performance measurement and reporting) was compiled by the author on behalf of the industry NRS 048 working group (WG) under the auspices of the Electricity Suppliers Liaison Committee (ESLC).

The WG membership included government (DPE), the distribution industry, National Energy Regulator of South Africa (NERSA), Eskom Holdings (Transmission, Distribution, KSACS, Research and Strategy) and end-customer representatives.

Medium voltage (MV) is defined as the set of nominal voltage levels that lie above low voltage and below high voltage in the range 1 kV $\leq$ Un < 44 kV [2].

The NRS 048-6 standard provides a future framework for the measurement principles, key performance measure definitions, high level event data quality assurance, data accuracy auditing requirements, and the requirements for distribution network interruption performance reporting in the South African electricity distribution industry (EDI).

The standard also provides the minimum requirements of an interruption performance management system for either the manual or automatic capturing and recording of interruption event data. The high level interruption cause codes are provided as a minimum requirement for associating the supply interruptions with a common industry cause code hierarchy. The relevant requirements for the disaggregation reporting as well as the annual regulatory reporting, benchmarking reporting and incentive based reporting are provided in the standard.

The overarching key principles and practical considerations for the implementation of the NRS 048-6 standard will be discussed in this paper.

It is hoped that the paper will stimulate discussion on the current preparedness, resource constraints and future requirements of the EDI. The information will be applicable to all the municipalities and metropolitans and will be of direct interest and benefit to AMEU members.

Additional technical information not covered in the paper can be found in the current draft of the NRS 048-6 standard. All AMEU members are encouraged to read the standard.

International regulatory mechanisms

Historically, international electricity regulators implemented a rate of return regulation (RORR) mechanism that had shortcomings in terms of managing the network interruption performance of a distributor.

The System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) are typical network interruption performance measures used by international regulators.

The current international trend is for electricity regulators to include network interruption performance targets (SAIFI and SAIDI) with penalty/reward mechanisms, along with the control of revenues of distribution companies, as part of incentive-based regulation (IBR). IBR requires an alignment of the capital investment programme, effective operating practices and maintenance programmes of the distributor licensee, so that these performance targets levels are met. The typical IBR period duration is 3-5 years (depending on the objective).

A potential future IBR environment (similar to the UK's regulatory environment) could be a focus on both SAIFI and SAIDI over the incentive period (3-10 years), but with more emphasis on improving SAIDI. The SAIFI could be sustainably improved by 0,5% to 1,0% per annum, with SAIDI sustainably improved by 15-30% over the incentive period. To improve SAIFI requires a long term approach and capital investment programme while improving SAIDI can be done over the short to medium term by optimising the operating and maintenance programmes.

It must be noted that IBR does not only relate to technical performance, but is an entire business efficiency and mobilisation step-change that cuts across all the departments, value chains, processes, systems, data, financial and human resource aspects of a distributor licensee.

Currently in Eskom there is a proposed distribution network interruption performance component (with financial penalties and incentives) of the Eskom Multi-Year Price Determination (MYPD) for 2006-2009.

An industry standard for the measurement and reporting of network interruption performance measures will be a critical component of any future IBR mechanisms in South Africa. In particular, the anticipated implementation of IBR will require accurate and consistent reporting methods and accurate and complete data collection, to facilitate appropriate target setting.

Key components of power quality

Power quality (PQ) comprises of quality of supply (QOS) and network interruption performance components as shown in Fig. 1. PQ is the measure of the quality of the electricity supplied (voltage waveform received by the customer), how reliable is the supply (frequency of interruptions) and how available is the supply (duration of interruptions).

QOS deals with voltage waveform quality and metrics such as voltage dips (X, Y, Z, T and S class), voltage regulation, harmonics, flicker and unbalance. The QOS measurement and reporting requirements is covered by NRS 048-2 [2].

Network interruption performance deals with the reliability (frequency related metrics) and availability (duration related metrics). These can be sustained interruptions (long) or momentary interruptions (short) that are experienced by individual customers. The measurement and reporting requirements is covered by NRS 048-6.

The key measures of the NRS 048-6 standard are:

- *Availability of supply* – the average duration of an interruption of supply experienced by the customer
- *Reliability of supply* – how frequently on average an interruption of supply is experienced by a customer
- *Restoration of supply* – the percentage of customers that had their supply restored within a specified target time after an interruption (based on NRS 047 requirements)

Fig. 1: The key components of power quality.

- *Worst served customers* – the percentage of individual customers that receive poor network interruption performance levels
- *MV and HV transformer unavailability* – the average duration of interruption of supply that affects MV/LV and HV/MV transformers only
- *Network reliability* – the frequency of interruptions occurring on network normalised to 100 km.

Overview of related NRS standards

Table 1 provides an overview of the current standards in the NRS 048 suite of documents.

High voltage (HV) is defined as the set of nominal voltage levels that are used in power systems for bulk transmission of electricity in the range 44 kV ≤ Un ≤ 220 kV [2].

The NRS 047-1 standard provides the quality of service required measurement and reporting requirements [1].

Compilation of the standard

In compiling this standard, the NRS 048 WG was guided by key local experiences and international developments such as the IEEE P1366 standard "Full use guide for electric power distribution reliability indices"; the work and recommendations of the international IEEE task force on reporting practices; the recommendations of Cigré Technical Report TB261, "Power quality indices and objectives"; the United Kingdom (UK) regulatory standard of the Office of Gas and Electricity Markets (Ofgem) "Quality of service regulatory instructions and guidance"; and the experiences and lessons learnt by Eskom Distribution and the various AMEU members.

The regulatory requirements of Nersa and the business and operational needs of the distributor licensees were taken into account in the preparation of this part of NRS 048.

In order to measure, assess, and audit the reliability and availability of electricity supplied by the distributor licensees, Nersa will require the distribution licensees to have uniform and robust measurement and reporting procedures in respect of network interruption performance. This will be important to reduce regulatory uncertainty and provide confidence in the interruption of supply related indices supplied by the distributor licensees of South Africa. In terms of the requirements and principles of economical and affordable electricity supply in South Africa, it is essential to achieve a fair balance between the cost and the adequacy of the measurement and reporting requirements.

Scope of the NRS 048-6 standard

The key aspects addressed in the NRS 048-6 standard are:

- Interruption performance measurement and data collection requirements
- Performance indices for reporting and the calculation method of these indices
- Segmentation according to voltage group (low, medium and high)
- Segmentation of network and a basis for future segmentation of customer types for reporting purposes
- Treatment and reporting requirements of major events
- Handling of exclusions and inclusions of events for the various reporting requirements
- Data collection of interruption cause codes according to a standard hierarchy
- Requirements for the disaggregation for annual regulatory, benchmarking and incentive based regulation reporting
- Data management and archiving and system related changes
- Estimating the accuracy of reporting through event data audits

The quality of service related measures (such as the number of planned interruptions starting and ending on time and the effective customer communication about pending planned interruptions) are not in the scope of this part of NRS 048 and are covered in NRS 047 (or future possible revisions). This standard only covers the technical performance measures experienced by the customers.

The standard provides for a range of indices that can be used for regulatory reporting and internal performance management by the distributor licensees. Some of these indices are customer-based (providing the average frequency and duration of interruptions experienced by the customers), or are load-based indices (providing the frequency and duration of loss of load) and others are network-based (providing the frequency and duration of interruptions on networks).

Performance indices defining worst-served customers are also provided to ensure that the performance levels of individual customers are also monitored (not "lost" in the reported average performance values), reported and improvement or mitigation projects implemented where necessary.

Definition of an interruption of supply

Supply interruptions refer to the complete (100%) voltage loss on one or more phases for longer than 3 s.

An interruption is not defined in terms of voltage measurements, but rather in terms of the disconnection of the supply point. Voltage measuring instruments may in some cases provide erroneous information of whether an interruption occurred or not. Instruments specified in accordance with SANS 61000-4-30 may be used to assist in the interruption assessment.

The interruption can be a sustained interruption or a momentary interruption of supply. A network event of duration 3 s or less and with partial or full voltage loss, is classified as a voltage dip [2].

Interruptions on HV networks

Momentary interruptions (HV): interruptions of supply in the range > 3 s to ≤ 1 minute.

Sustained interruptions (HV): interruptions of supply with duration > 1 minute.

In general a 1 minute limit differentiates all automatic recloser operations (ARCs) from

Standard title	NRS 048 Part	Current status
Voltage characteristics, compatibility levels, limits and assessment methods	NRS 048-2	Finalised and sent for ELSC voting
Application practices for licensees	NRS 048-4	Finalaised and sent for ELSC voting
Medium voltage network interruption performance measurement and reporting	NRS 048-6	Final draft and WG and ELSC voting pending
Application practices for end customers	NRS 048-7	Draft and work in progress
HV and EHV network and large customer ineterruption performance measurement and reporting	NRS 048-8	Proposed future work and pending ELSC approval

Table 1: Overview of NRS 048 standards.

events involving manual operator intervention. The 1 minute classification aligns with the commonly used international classification of 1 minute for sustained interruption of supply for transmission distributor licensees.

Interruptions on MV and LV networks

Momentary interruptions (MV/LV): interruptions of supply in the range > 3s to ≤ 5 minutes.

Where an interrupting device has a sequence of operations, those momentary interruptions shall be counted as separate momentary interruptions.

Sustained interruptions (MV/LV): interruptions of supply with duration > 5 minutes.

Sustained interruption indices

The following are the key sustained interruption indices used and their definitions.

SAIFI (System Average Interruption Frequency Index): The SAIFI of a network indicates how often on average (frequency) the customer connected would experience a sustained interruption per annum. Mathematically SAIFI can be expressed as:

SAIFI = Total number of customer interruptions p.a./total number of customers served (1)

SAIDI (System Average Interruption Duration Index): The SAIDI of a network indicates the average duration of a sustained interruption the customer would experience per annum. It is commonly measured in customer minutes or customer hours of interruption. Mathematically SAIDI can be expressed as:

SAIDI = $\sum$ customer interruption durations p.a./total number of customers served (2)

CAIDI (Customer Average Interruption Duration Index): The CAIDI of a network indicates the average duration of a sustained interruption that only the customers affected would experience per annum. It is commonly measured in customer minutes or customer hours of interruption.

This index differs from SAIDI in that only the total number of customer interruptions is used in the denominator and not all the customers served. Mathematically CAIDI can be expressed as either:

CAIDI = $\sum$ customer interruption durations p.a./total number of customer interruptions (3)

Numerically SAIDI = CAIDI x SAIFI. The general case is for CAIDI < SAIDI, as CAIDI only takes into account the number of affected customers.

HSLI (HV Supply Loss Index): The HSLI of a network indicates the average network loss duration by the HV plant installed due to sustained interruptions caused by only distribution per month. It is a measure of the HV transformer unavailability and is expressed as minutes per month. The HSLI will also include HV plant that has been affected by MV related through faults on the network. Mathematically HSLI can be expressed as:

HSLI = $\sum$ MVA hours lost per month/installed HV MVA base (4)

The HSLI is comparable to the transmission system minutes (SM) measure, but using the installed transformer rating (name plate rating) instead of the actual load interrupted that is measured.

MSLI (MV Supply Loss Index): The MSLI of a network indicates the average network loss duration by the MV and LV plant installed due to sustained interruptions caused by distribution only per month. MSLI is mathematically similar to Eqn. 4 above but with the MV transformers and MV related MVA used in the equation. It is a measure of the MV transformer unavailability and is expressed as hours per month.

The above indices can be further broken down into their planned and unplanned components for detailed reporting and analysis.

Interruption categories for reporting

In order to facilitate the various reporting requirements, categories and associated sub-categories of sustained and momentary interruptions are listed here.

The detailed definitions and application of the interruption categories is provided in NRS 048-6.

Unplanned interruption ("U"):

- Network event ("UN")
- Emergency ("UE")
- Major event ("UM")

Planned work ("P"):

- Pre-arranged ("PA")
- Major event ("PM")

The planned work activity categories are covered in NRS 082. For the purposes of this part of NRS 048, the planned work execution refers to all planned (corrective and preventive) work activities that results in an interruption of supply experienced by the customer.

Customer related ("C"):

- Customer caused ("CC")
- Customer requested ("CR")

Intake supply related ("S"):

- Unplanned ("SU")
- Planned ("SP")
- Load shedding ("SL")

The supply related category also includes the unplanned interruptions caused by or the planned interruptions requested by distributed generation.

Load-shedding-related interruptions are indicated for completeness. These events shall be carefully recorded, assessed and reported separately. These interruptions must not be included in the normal network interruption performance statistics.

Principle of re-interruptions

Subsequent interruptions due to fault finding or network operating or switching that are associated with the original network interruption shall be referred to as a "re-interruptions". These subsequent interruptions need to be carefully considered, so that they are not unnecessarily included in the network interruption performance index calculations and unfairly penalise the distributor licensee with "double counting" of interruptions. Counting the subsequent interruptions due to fault finding and network switching unfairly penalises the licensee and forces incorrect behaviour and fault finding and restoration of supply practices from field staff.

Any re-interruption must occur less than three hours after the first interruption and with the cause code of the interruption at the same physical location on the network as the original interruption. The actual interruption duration time will be used (sum of all the interruptions experienced), but the frequency will only be counted as one interruption. Re-interruptions only apply to unplanned related work.

An interruption occurring three hours or longer after the previous interruption will be counted as a new interruption, even if occurring at the same location on the network.

The international average for CAIDI is around two hours per annum. Setting a re-interruption time window of three hours would therefore be appropriate. The UK regulator (Ofgem) also specifies a re-interruption time of three hours for annual performance reporting.

The above concept of a re-interruption can be illustrated by the following example. A MV network has a loss of supply of one hour for all its connected customers; the whole network has supply restored for 30 minutes (assuming no supply step restoration); the whole network has a further loss of supply for 30 minutes, the entire network then has supply permanently restored. The network event would be reported as all the customers experiencing one sustained interruption for a total duration of two hours.

The distributor licensee is still encouraged (and in future regulatory incentives funding will hopefully be made available) to restore supply to the customers in the shortest possible time through distribution automation, network monitoring system, network back-feeding and flexibility and reduced travelling time etc.

The practice of re-interruptions will result in a statistical step increase in the current SAIDI levels and a statistical step decrease in the current SAIFI levels of a distributor licensee. This will result in a reported SAIFI and SAIDI values that are more accurate and controllable via appropriate improvement or mitigation strategies to be implemented. This will require the recalculation of historical data and the recalibration of targets to reflect the adjusted data.

Pre-arranged planned interruptions

A planned interruption shall be categorised as "pre-arranged" when an item of plant or section of network is deliberately and in a co-ordinated manner taken out of service (by the distributor licensee or its appointed agent) at a selected date and time. All the affected customers shall have been notified of the planned interruption in accordance with the minimum period prescribed in NRS 047, or as otherwise contractually agreed.

Planned work is usually for the purposes of construction, preventive maintenance, refurbishment or repair. Currently NRS 047 specifies a 48-hour planned interruption notification time for customers.

When the planned and co-ordinated interruption of supply to the customer or group of customers involves a number of successive switching operations resulting in numerous interruptions, then the interruptions are all counted as a single planned interruption.

There needs to be a clear separation of the technical performance and quality of service related measures. The technical performance measures are based on the actual supply interruption times experienced by the customers.

The quality of service measures are based on the scheduled interruption time by the licensee, who surveys the customers in terms of their satisfaction. A measure of the number of planned interruptions finishing later than the notified time can be established in NRS 047 to provide a measure of the distributor licensee's quality of service provided.

Customer network link (CNL)

Data connectivity refers to the complete and accurate model of the number of customers connected to a transformer affected by an interruption. The process of connectivity refers to the ability of the system to infer the interruptions on to all the affected customers (even those customers who did not call in) from the HV system to LV customers connected to MV/LV transformers, from data related to the received calls or the location of the affected device on the network. Allowance must be made for an accurate and complete customer connectivity model from the HV system to the LV customers connected to the MV/LV transformers.

The customer connectivity model shall be maintained and updated regularly by the distributor licensee. The connectivity model should have the following recommended end-state minimum data accuracy and completeness levels:

- *HV customers:* > 99% of all HV customers accurately linked
- *MV customers:* > 95% of all MV customers accurately linked
- *LV customers connected to MV/LV transformers:* > 75% of all LV customers accurately linked.

These percentages are based on the end state. It is recognised that licensees may not be at the current completeness levels and will require time to reach the required levels of completeness.

The distributor licensee needs to justify to Nersa the appropriate and practical required customer connectivity levels for HV, MV and LV customers. The distributor licensee will need to justify to Nersa levels less than the above recommended levels based on their particular operating environment, business circumstances and resource constraints, etc.

Accuracy guidelines of the annual interruption measures reporting

The accuracy of the network interruption performance measures will be critical in future IBR environments and annual regulatory reporting. The information that follows here will apply once the systems are functional and there is confidence in the reported measures.

The distributor licensee shall be required to have a minimum accuracy level of 95% for the number of customers interrupted and 95% for the duration of interruptions of supply.

The accuracy levels apply to both HV and MV connected customers that experience sustained interruptions. It is a requirement that both the accuracy levels for the number of customers interrupted and the duration of interruptions of supply, are met by the licensee.

The distributor licensee is to ensure the appropriate levels of completeness and accuracy of the levels of interruption performance reported. This can be determined by an audit at the end of each reporting period. The distributor licensee shall be required to have the customer network link greater than or equal to 95% in the reporting period.

The initial accuracy level of 95% may be relaxed to take into account the current data connectivity model and data maturity of the licensee. It is proposed that the licensee conducts a self-audit annually, but this may become a future regulatory requirement. The reporting accuracy levels will be critical once IBR is implemented.

The accuracy levels of HV and MV networks required may be increased in future regulatory requirements. It is also possible that accuracy levels for LV networks and for momentary interruptions are introduced in the future.

Customer categories

The following type of customer category descriptions and relevant information shall be reported on (the type of customer affected by the interruptions):

- *Residential customers (large)* - customers that use electricity at their place of residence and typically have an ADMD > 1. (This includes customers that work from home.)
- *Residential customers (small)* - customers that use electricity at their place of residence and typically have an ADMD ≤ 1. This type if customer is normally funded from the National Electrification Fund or similar government grants and cross-subsidies.
- *Agricultural customers* - customers that use electricity for the purpose of economic activity related to agriculture. (i.e. farming, and mostly include supply to the household.)

It is recognised that there may be a hybrid urban-agriculture customer category. Typically this would be subsistence farms, fish farming and topical city initiatives (i.e. mushroom and worm farming).

- *Industrial customers* - customers that use electricity for the purpose of industrial production, mostly situated in declared industrial areas. This category includes mining-related customers.
- *Commercial customers* - customers that use electricity for the purpose of trading activities, normally situated in declared commercial areas. This includes tourism, retail, banking and education.

The customer category descriptions are intentionally broad to accommodate the majority of customer types in South Africa. Distributor licensees may use more exact definitions to better suit their business, as long as they align with the broad customer descriptions above. This is to ensure uniform and consistent customer interruption reporting in South Africa.

Interruption performance levels per customer categories are a long term regulatory reporting requirement as part of an effective and value adding incentivised regulation approach. The customer database of the distributor licensees will need the customer category identified and recorded for reporting. The relevant timelines and compliance level required for distributor licensees to start recording and reporting customer categories, will be decided by Nersa in consultation with all the relevant distribution stakeholders.


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Classification of major events

A major event is considered to occur when there are conditions or events on the network that result in many customers affected, or a significant amount of installed MVA lost (installed transformer rating), or results in supply restoration times longer than that expected under normal conditions as specified in criteria A and B here.

The major events for MV networks as defined here shall be removed from the network interruption performance indices and reported separately by the distributor licensee. The intention is to report the actual underlying performance level that is not distorted by abnormal events that are out of the distributor licencee's control. The distributor licensee shall proactively manage both the underlying performance related interruptions and the abnormal performance related interruptions.

Major event criterion (A) (for annual regulatory reporting and distributor licensee comparison on a national basis)

An unplanned interruption shall be categorised as a "major event" for distribution comparison reporting purposes, where any one of the following conditions are met:

- More than 50 000 customers are affected and are without supply for 24 hours or longer due to a single event.
- More than 50 MVA of the aggregated HV supply side ratings of the downstream installed transformer capacity and off for 24 hours or longer

The firm transformer capability or redundancy needs to be removed for the second condition above to prevent double counting and only the supply side transformer capacity used in the MVA calculation.

The major event (criterion A) uses a fixed quantum that will allow for equitable and consistent comparison of small and large distributor licensees in South Africa. Some of the larger distributor licensees may report many major events according to criterion A, due to the large customer base or large installed MVA. Some of the smaller distributor licensees may report a few number of major events. The intention is to normalise the major events for large and small distributors and provide a consistent national picture.

Major event criterion (B) (for annual reporting and year-on-year licensee performance tracking and self comparison)

An unplanned interruption shall be categorised as a "major event" for reporting where any one of the following conditions are met:

- More than 10% of the installed customer base of the distributor licensee is without supply for 12 hours or longer
- More than 10% installed MVA transformer base of the distributor licensee is without supply for 12 hours or longer
- Through a specific agreement in writing between the relevant distributor licensee and Nersa and that is published on the Nersa website in the public domain.

This criterion will allow for the aggregation of South African statistics and assist in determining the underlying performance trends for regulation purposes.

The major event criteria will be applied as per the formal areas of distribution of each distributor licensee. For example, in Eskom Distribution the major event criteria will be applicable to the individual regions.

Worst served customer measures

The worst served customer related indices ensure that the network interruption performance levels experienced by the individual customers are still within the reasonably expected performance levels. The objective is to report reliability and availability of supply trends as per the three measures below that are reflective of the network interruption performance of the individual customers. This includes planned and unplanned components.

It will be necessary to determine the following indices:

- Percentage of customers with single supply sustained interruptions of longer than a specified number of hours per annum per event
- Percentage of customers experiencing more than a specified number of sustained interruptions per annum

The sustained interruption calculation definitions and calculating method shall be applied. The quantum for the above need to be established by the relevant licensee in consultation with Nersa.

The distributor licensee is accountable for the effective management of its poor performing networks or worst served customers.

Interruption cause code categories

This section presents a minimal set of data codes and a consistent categorisation structure necessary for interruption cause code collection, reporting and the comparison of distribution network performance in South Africa.

There are 15 identified primary cause codes (A to O) and corresponding secondary cause codes to provide high level information about the cause of supply interruptions, ensure a common interpretation, and assist in the uniform and consistent reporting among all distributor licensees.

Broad categories were intentionally established to help minimise data collection efforts by distributor licensees. There are numerous other categories that could be selected, but with the goal of uniformity and simplicity for comparison purposes and practicality, these primary and secondary cause codes were selected. Allowance is made for those causes not covered (other category) and those causes that are unknown (unknown category)

Overview of categories

The primary cause of supply interruptions shall be categorised as follows:

A : Equipment failure

A1 : Cable circuit (including any terminations to lines or other circuits)

A2 : Overhead line (including associated equipment, but excluding transformers)

A3 : Transformer (including tap changers and voltage regulators)

A4 : Reactive control devices (capacitor, reactors)

A5 : Switchgear

A6 : Terminal equipment and busbars and related terminal equipment

A7 : Protection system failure (fuse failure)

A8 : Control system failure (SCADA)

A9 : Other

The distributor licensee may have sub-levels of the above high level categories

B : Planned work

The planned work category includes all interruptions that are planned.

C : Operational causes

C.1 : Incorrect protection operation (settings/ fuse-sizing)

C.2 : Incorrect control equipment operation

C.3 : Licensee operator error or licensee's contractor error

C.4 : Emergency

D : Supply intake (non-distributor licensee caused)

D.1 : Loss of supply due to technical problem

D.2 : Loss of supply due to non-payment

E : Vegetation

The vegetation category includes interruptions caused by falling trees and growth of trees into lines. It should be noted that if a tree is involved, the cause category is "vegetation". This is important to note during windstorms. It may not be possible to determine that a network may have a forestry issue if wind is listed as the cause when actually a tree was involved. Interruptions caused by the combination of wind and vegetation shall be recorded under this category.

F : Fire

F.1 : Sugar cane fires

F.2 : Veld/bush fire

G : Natural events

G.1 : Storm (lightning/wind)

G.2 : Snow/ice

G.3 : Significant events (earthquakes and tornadoes)

H : Insulation pollution

H.1 : Industrial

H.2 : Natural (e.g. salt air, excluding birds)

H.3 : Fire-related

H.4 : Other

I : Wildlife

I.1 : Birds (physical contact/bird streamers/ pollution etc)

I.2 : Other

J : Customer

K : Theft and vandalism

L : Third party

Including cables ripped/dug up by contractors or collisions

M : Unknown

The unknown category includes any interruptions where a definitive cause cannot be determined even after a formal investigation. The distributor licensee shall provide a brief description of each interruption assigned to the other category. The number of interruptions classified as unknown shall be kept to a practical limit.

O : Other

Any interruptions that do not fall into any of the above primary cause code categories should be assigned to the "other" category. The distributor licensee shall provide a brief description of each interruption assigned to the other category.

Application of codes

The proposed interruption cause code hierarchy is not a detailed or formal root cause analysis tool, but only a high level tool to categorise the causes of interruptions into logical and systematic categories to assist with identification of potential problems areas and the application of mitigation projects or improvement initiatives.

The interruption cause code categories will assist in future interruption performance benchmark exercises, so it is critical that accurate and reliable data is captured by distributor licensees.

Annual regulatory reporting

When providing interruption performance data, the exclusion of any categories of interruptions shall be clearly specified by the distributor licensee with the submission to Nersa. It is anticipated that Nersa will clearly define which categories need to be included or excluded in the reporting requirements.

The annual reporting shall be on a calendar year basis. Annual reporting in the case of all licensees ensures that common events that affect various licensees are reported and consolidated or the industry by Nersa for the same period.

System interruption performance statistics

The following network interruption performance information shall be reported by the distributor licensee as part of the future annual power quality (PQ) report to Nersa:

- SAIFI
- CAIFI
- SAIDI
- CAIDI
- MSLI
- HSLI
- Interruptions/100 km (overhead and underground networks reported separately)
- MAIFI
- MAIFIe
- MInterruptions/100 km (overhead and underground networks reported separately)
- Worst served customers
- Customer supply restoration times
- Number of major events occurring, the impact of the major event on the indices and the supply received by the affected customers in a geographical area and the comprehensive investigation report dealing with the cause of each major event
- Number of voluntary and involuntary load reduction events and the relevant information of each event

Note that the system level performance reported needs to be the customer weighted average of the relevant districts or areas

The above reported interruption performance indices shall be reported separately as per the following categories:

- Unplanned interruptions
- Planned interruptions
- Overall performance (unplanned, planned components and HV and MV combined)
- HV (where applicable)
- MV (where applicable)
- 33 kV (where applicable)
- The interruption performance including and excluding major events as per category A
- The interruption performance including and excluding major events as per category B

Categories for exclusion

The following shall be excluded from interruption performance indices, but the relevant information reported about these categories separately:

- Customer caused and requested interruptions
- Intake supply-related interruptions
  - Non-load shedding related
  - Load shedding related

Technical commentary and cause codes

The following additional key information is also required to be reported:

- Technical commentary report on the network interruption performance levels and explanation of any poor performance with the relevant action plans or initiatives to improve the performance
- The interruptions experienced per cause code with a high level pareto analysis and technical commentary.

Reporting for incentive based purposes

Reporting for incentive-based purposes shall be agreed between Nersa and the licensee – but is likely to be on a financial year basis or linked to tariff application periods.

Nersa will determine, in consultation with distributor licensees, which network interruption performance indices are to be used in the incentive based regulation. The following shall be excluded from the interruption performance indices reported:

- Major events (reported individually)
- Intake supply related events
- Customer related events
- Voluntary and involuntary load reduction cause interruptions
- Customer caused or requested interruptions

The planned and unplanned component interruption indices shall be reported separately to encourage the correct behaviour of licensees in managing the network faults and planned work programme.

Local and international benchmarking

Caution needs to be exercised when conducting network interruption performance benchmark exercises. Interruption performance benchmarking requires careful consideration of not only the physical conditions related to the peer group members (e.g. network type and topography, environment, geography, network operating practices and human resource related elements), but also of the measurement, data collection and storage and reporting methods used.

Through specifying the latter (taking international practices and key developments into consideration), the NRS 048-6 standard aims at providing an improved basis in South Africa for undertaking such internal and international benchmarking activities into the future.

Nersa needs to compare "apples with apples" for accurate and reliable interruption performance reporting and possible benchmarking between the distributor licensees in South Africa and potentially with international distributor licensees. This document will also in the long term assist in determining which best work practices and processes distributor licensees should implement, to improve their interruption performance to acceptable levels (and increased customer satisfaction).

Conclusion

The NRS 048-6 standard provides a solid framework for future requirements of network interruption performance measurement and reporting in South Africa. In particular, the anticipated implementation of incentive based regulation (IBR) will require accurate and consistent reporting methods and accurate and complete data collection, to facilitate appropriate target setting.

It is recognised that present systems (SCADA coverage and interruption databases and systems) of the distributor licenses do not meet the minimum requirements specified in this standard and that there are also resource and financial constraints.

It is recommended that the initial implementation of this standard will require a phased-in approach (three-five years) and that Nersa will specify the time frame and compliance level for such implementation, in consultation with the various distribution industry stakeholders.

It is also recommended that Nersa establishes an industry committee (similar to the previous NER PQ Advisory Committee) of all the relevant role-players in the distribution industry to ensure common understanding of the key principles, provide a forum for the discussion of the implementation of this standard. The challenge is now for the distributor licensees to implement the NRS 048-6 standard and start improving their electricity service delivery – reliability and availability of supply.

Acknowledgements

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- Robert Koch, R&S Division, Eskom Holdings
- Tshilidzi Thenga, Nersa

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[1] NRS 047-1 : Quality of service

[2] NRS 048-2 : Voltage characteristics, compatibility levels, limits and assessment methods Δ

Regulation of electricity metering in South Africa through NRS 057

by Henri Groenewald, Eskom

Formal metering regulations for the electricity supply industry have been developed and documented through NRS 057 – Code of electricity metering. The NER has recently amended the licence agreements of electricity supply authorities by including NRS 057 in their supply agreements.

Electricity supply authorities will need to evaluate the requirements of NRS 057 and amend their operating environment for metering to align with NRS 057. This paper portrays the implications of the regulatory aspects for the electrical energy metering process.

NRS 057

NRS 057 is a generalised code of practice which promotes uniform electricity metering requirements for application in the South African electricity supply industry. The requirements have been specified based on similar international practices applied within electricity metering.

The regulatory requirements are applicable to electricity metering in its entirety, including all equipment requirements, design requirements, maintenance requirements, metering data capturing and data retention requirements and service agents' requirements.

Many of the provisions of NRS 057 have significant impact on the way that electricity supply utilities will conduct metering in the future. NRS 057 contains requirements which electricity supply utilities may only be in a position to conform to progressively and the electricity supply utilities need to engage with the NER to formulate and agree on an implementation plan. The following paragraphs provide an overview of the major impact areas related to the requirements of NRS 057.

Installation design requirements

The installation design may not necessarily be done by the electricity supply utility's own staff, and can in many cases be done by consultants. Everyone involved should make themselves familiar with the minimum requirements that need to be taken into account with the installation design.

Metering installations have been categorised based on the supply size that is to be metered. Minimum equipment class accuracies were specified for each of these categories. The relevant international specifications were also listed for the major equipment in a metering installation.

The design should not only specify the correct equipment to be installed, but should also aim to minimise the technical losses by specifying the correct cabling to measurement instrument transformers and by specifying the correct current instrument transformer ratios to be used.

Maintenance requirements must also be considered through the design by providing for the appropriate ancillary test equipment and test points in the metering circuits.

Approved equipment

The licensee is responsible for maintaining a list of approved metering equipment to be used in its metering installations.

Metering equipment must be evaluated to determine if it meets requirements based on international standards and the electricity supply utility's own requirements. Type test records from a SANS recognised facility must be available for all major components of a metering installation.

Large electricity supply utilities may be in a position to perform such evaluations in-house, but smaller utilities may not have the necessary resources to do so. They will have to either contract the work to external consultants or establish an agreement with a larger utility to adopt their approved listing.

Metering equipment installation

NRS 057 is very specific with the requirements pertaining to the equipment installation.

Voltage and current instrument transformers used in the installation must be accompanied by calibration test certificates obtained from a SANAS accredited test facility. The major manufacturers of CTs and VTs do not have SANAS approved testing facilities. They may use equipment that has been calibrated at a SANAS accredited facility, but their own operating environments are not SANAS approved. Manufacturers need to invest in SANAS accreditation for the testing of CTs and VTs. Electricity supply utilities will thus not be able to comply with this requirement at this stage, but they need to put pressure on the manufacturers to implement formal accreditation.

The same argument is relevant to the manufacturers and suppliers of electricity meters. Utilities must have records of calibration certificates for each meter. There are only a few test houses that have obtained SANAS accreditation for the calibration of energy meters, but this may also change once utilities specify this requirement in their tenders.

NRS 057 not only specifies the requirements for equipment to be installed, but also the requirements for the staff that is responsible for the installation and commissioning of the equipment. NRS 057 has categorised installations based on the complexity of the installation. For each category certain minimum requirements are specified for staff related to technical qualification, training and experience.

The electricity supply utility may only contract staff for commissioning of installations that meet the requirements as specified for that installation. To ensure conformance to this requirement the utility will have to maintain a list of accredited staff or contractors for specific work.

Installation maintenance

Metering installations need to be maintained at minimum intervals and the frequency of maintenance is based on the supply size. Utilities will need to align their maintenance policies with the frequencies as specified in NRS 057.

Certain minimum requirements are specified for meter installation maintenance. Not only must installation equipment be re-tested, but the metering data must also be evaluated to determine if the final billing data is aligning with meter advances. Staff which is responsible for maintenance must again conform to certain minimum requirements related to technical qualification, training and experience.

Metering access

NRS 057 specifies that access by customers or customer representatives to meters, metering circuits and metering data shall be restricted to ensure that the integrity of the metering device, metering installation and meter data are not at risk. This requirement safeguards the electricity supply utility from risk to the metering installation, but the customer has a right to obtain his metering data from the supply utility. The supply utility must therefore be able to provide for historical metering data upon request from the customer. A web-based application with password control may prove to be the best solution for electricity supply utilities.

Current and voltage instrument transformers must be dedicated to the utility's metering equipment. Customer equipment may thus not be installed into the utility's CT and VT circuits. Customers and consultants must take this requirement into consideration when providing for a design on additional metering equipment.

Metering data access

NRS 057 specifies minimum intervals for retrieving billing data from meters in the field (pre-payment meters excluded). The frequency for obtaining the billing information is again based on the supply size of the installation.

The electricity supply utility needs to put the necessary plans in place to obtain the billing data at the pre-determined intervals. Technology today provides for ease in obtaining billing information. Automated meter reading may be one solution to achieve this requirement.

Metering data validation

Metering data must be validated before the bill is produced to check for inaccurate data, missing data, consumption that is not is line with the customer historical data etc.

A log must also be kept of any changes or estimations that are made to the billing data.

Frequencies are also specified for the validation of meter billing data versus meter advances. Only a few utilities have this requirement in place for their customers.

Where monthly meter reads are taken directly from the meter (manual reading) this validation is simple to check against data in the billing system, but where automated metering is employed the validation becomes involved.

Typically the AMR system obtains metering interval data (kWh and kvarh) per half hour – the AMR system does not obtain meter advances. Multiplication constants are applied to these half-hourly values to get the final billing values. There is a chance that errors can be introduced in this billing process through manual operation by system operators. It is thus important to validate the actual meter advance to the final billing values to determine if the whole billing process is accurate.

Metering data retention

Five years of historical billing data must be kept by the electricity supply utility.

If the billing was done from interval data, then the interval data must also be available for at least five years. Any logs on data estimations must also be kept for at least five years.

Conclusion

By including NRS 057 in the license agreement of electricity supply utilities, the requirements have become regulatory and it has a definite impact on the metering process being employed by the utilities.

Some requirements cannot be implemented immediately, but it is the responsibility of each electricity supply utility to formulate and establish an implementation plan for these requirements. Δ

Update on accelerated ageing of MV XLPE

by A Falconer and G Wyte, Aberdare Cables

In October 2001 a paper was presented [1] at the 4th Southern Africa Regional Conference of Cigré in Somerset West detailing the state of accelerated ageing testing of MV XLPE in South Africa. At that stage although the tests were already defined in SABS 1339 and SABS SM 1284-5 (later known as SANS 1339 and SANS 6284-5 respectively), there were no functional test rigs operating in South Africa.

Since then some have been built and this paper describes both the good and the bad experiences of the Aberdare rigs at the Aberdare test centre in Port Elizabeth.

What follows is a simplified view of a very complicated subject!

Crosslinked polyethylene (XLPE) as an insulation arrived on the scene around the 60s. Although its potential as a terrific electrical insulation was appreciated, the material was not fully understood and was found to have a failure mechanism, now generally referred to as water treeing, that had not been predicted. The trouble was that the mechanism took in excess of 5 years, typically from 8 to 12 years, to manifest itself. This compromised electrical MV networks around the world many years after XLPE cables had been installed. Understandably the technology acquired a bad name and much effort was put into understanding the problem, engineering it out of cables, and developing tests that demonstrated that the problem had been addressed.

Superficially, polyethylene is not a particularly complicated material. It consists of extremely long chains of carbon atoms joined by single bonds, with hydrogen atoms attached to the remaining two bonds on each carbon atom (... – CH_2 – CH_2 – CH_2 – ...). A chain can contain up to 100 000 carbon atoms. Occasionally additional shorter polyethylene chains will attach to a chain at the site of one of the hydrogen atoms, and the distribution of such side chains will influence the material properties and density, giving us materials such as low density polyethylene (LDPE), medium density polyethylene (MDPE), and others. When this material is used as insulation we arrange for the chains to be bonded to each other at a few sites along each chain in a process known as cross linking, producing XLPE.

The failure mechanism that had not been understood, was a subtle change in the material at various specific points, that then progressed slowly through the material creating structures that are tree-like in appearance. Some would start at contaminants or voids within the material and grow in opposite directions looking like a bow tie, while others would start at contaminants or blemishes on the surface of the material. Although the material in these structures remained a good insulation, its insulation properties compared to healthy XLPE were somewhat reduced. The mechanism of creation and propagation is very complicated, and relies inter alia on the existence of mobile ions. As the mobility is usually provided by water, the structures became known as water trees. (See Fig.1.) A cable infected with water trees will, in all probability, still function well under normal steady state circumstances. The problem comes when such a cable experiences a voltage spike that exceeds the breakdown strength of the water tree material, leading to the initiation of an electrical tree which will inevitably cause the cable to fail. As we all know, every MV distribution network is subjected to the occasional voltage spike.

Accelerated ageing of MV XLPE

The purpose of an accelerated MV XLPE ageing test is to realistically simulate about 10 years of cable use in the shortest time possible. The most accurate way of doing this would of course be to use the cable in service for 10 years, but waiting this long is somewhat problematic for both users and suppliers. Much work has been done on aspects that influence the speed of water tree growth and aspects that could prove useful are [2]:

Ions - The presence of ions is essential.

Electrical stress - Also essential as water trees will not develop in a cable that is not energised.

Mechanical damage - These make good initiation points, particularly for vented trees, as they distort the electrical field and are exposed to an unlimited supply of ions from the environment.

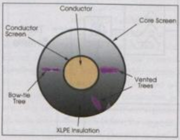

Fig. 1: Types of water trees.

Contaminants - These make good initiation points as they can distort the electrical field as well as provide ions.

Humidity - Water will provide the ions with mobility. It has been shown that water trees can grow if the humidity within the insulation is above 65%.

Voids - These can initiate water trees by causing mechanical damage. They are also sites for partial discharges.

Frequency - This exerts some influence, although growth rate is certainly not proportional to frequency.

Temperature - This also exerts some influence.

All accelerated aging tests make use of one or more of the above, with the exception of voids and internal contaminants which would be a function of the manufacturing process rather than a subsequent test.

Tests implemented in South Africa

As with most of the test methods developed in the world the South African methods follow three basic steps:

Pre-conditioning - This removes the by-products of manufacture and thoroughly wets the cable sample, ensuring that all samples start in the same condition.

Ageing - Simulate about 10 years of use by providing some of the aspects mentioned above that increase water tree growth rate.

Assessing - This employs a Weibul statistical approach, causing rapid "wear and tear" by applying high voltages in a controlled manner, until each sample section is destroyed. The distribution of the breakdown voltages determines if the sample passes or fails.

In South Africa the preconditioning is carried out under water at a temperature of 50°C for 1 000 hours, or just under 42 days. The samples are then aged underwater at room temperature at 3 U_0, which for an 11 kV cable is 19,1 kV. There are two methods described in the SABS tests:

50 Hz - The sample is energised at mains frequency for 17 500 hours, which is 2 years. This is fairly simple to perform.

500 Hz - The sample is energised at 500 Hz, with a sinusoidal wave form, for 3000 hours, which is 125 days. Producing a 19,1 kV 500 Hz sinusoidal voltage to energise a capacitive load is a big challenge, but the test provides results very quickly.

After ageing, 12 sample sections are then prepared and subjected to a voltage that increases in steps until the sample section fails. The sequence starts at 3 U_0, which is held for 5 minutes and then progresses in U_0 steps, with each voltage being held for 5 minutes. The voltage recorded is the last voltage held for 5 minutes. The pass criteria are:

- All 12 samples must pass a calculated maximum stress of 14 kV/mm.
- At least 9 samples must pass a calculated maximum stress of 18 kV/mm.
- At least 5 samples must pass a calculated maximum stress of 22 kV/mm.

The South African tests are similar to a test carried out in Europe, covered in Cenelec documents HD 620 and HD 605, excepting that the test parameters are slightly different. In the European test the final value recorded for each sample is the voltage at which the sample was destroyed, as opposed to the highest voltage held for 5 minutes. In order to pass, these voltages must have the same minimum criteria as those described above. The rigs at Aberdare are capable of performing the South African and European tests and some of the results given below relate to the latter.

(Note: it would be incorrect to draw conclusions about the likely performance of a marginal sample to South African standards based on voltages recorded in a European test, and vice versa, as the preconditioning and ageing parameters are different and the distribution of breakdown voltages will not necessarily correspond.)

Test No	Insulation Material	Standard	Frequency Hz	Completion	Result
1	Material 1	Cenelec	50	09/05/04	Passed
2	Material 2	Cenelec	50	02/08/05	Continual failure, stopped at 12418 h.
3	Material 3	Cenelec	50	13/02/05	Passed
6	Material 3	SABS	50	-	In progress, 35% complete.
7	Material 3	SABS	500	17/02/04	Passed (before upgrade)
8	Material 3	SABS	500	28/12/04	Passed (after upgrade)
4	Material 4	Cenelec	50	25/04/05	Continual failure, stopped at 1148 h.
9	Material 4	SABS	500	07/06/05	Failed
5	Material 5	SABS	50	-	In progress, 30% complete.
10	Material 5	SABS	500	-	In progress - preconditioning
11	Material 6	SABS	500	-	In progress, 25% complete.
12	Material 7	SABS	500	-	In progress - preconditioning

Table 1: Summary of tests.

Aberdare's test rigs

Preconditioning is carried out at Aberdare in a single dedicated stainless steel tank. The samples are wound on to a stainless steel drum specifically designed for the test. We have found that for acceptable conductivity during the test, it is necessary that the samples are taped with a helical copper tape. The temperature of the water in the tank is controllable. As the samples are each at least 150 m long our tank holds only one sample, and we are therefore limited to eight tests a year. However, where space is available in the ageing tanks, and there is no temperature conflict, preconditioning can be done in an ageing tank as well.

As a standard, all the cores we test are for 11 kV cables, and the conductor size we choose is 185 mm².

Ageing at 50 Hz is relatively simple. We use a variac to supply power factor correction equipment and a step up transformer. With this arrangement the load of a single sample on the variac is less than 5 A. Ageing is done in a separate 50 Hz stainless steel tank large enough to hold three samples on their stainless steel drums. Once again the water temperature can be controlled.

At 500 Hz the test is far more of a challenge. This is because the waveform must be sinusoidal, and the reactive power rating of a sample at 500 Hz is 10 times higher than at 50 Hz. The energising supply is achieved using a pulse width modulator modulating an 11 kHz signal at 500 Hz. The result is fed through a 4th order band pass filter, which includes the step up transformer and allows for power factor correction. Much effort was required to get this to work! The control diagram is depicted in Fig. 2.

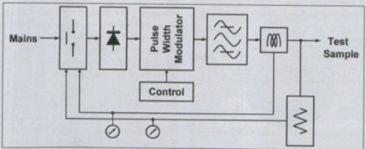

Fig. 2: 500 Hz generation.

The breakdown assessing is achieved using a 300 kV 300 kVA transformer giving us a continuously variable voltage. The protection equipment used is very fast in order to limit the damage at the breakdown site, so that we can then examine the area for water trees. Given that a typical breakdown voltage will be around 90 kV, and all the way up to 150 kV, a normal termination will simply not work. For this reason we use reusable water terminations rated up to 350 kV.

Operating experience

Once we realised the advantage of installing the power factor correction equipment between the variac and the transformer on the 50 Hz rig, instead of on the supply side of the variac, we found operation of this equipment to be very easy.

In the case of the 500 Hz system we found that the equipment was very sensitive to temperature variations. After much analysis, we established that the reason for this is that the filter of necessity has a pole, where its impedance is very high and transfer voltage low, and a zero where the impedance disappears, very close to one another. The separation of the pole and the zero is a function of the step up transformer ratio and, as such, cannot be changed. As a result, including the modulator in a control loop was found to be almost impossible and the circuit was quite unstable. We are presently developing a control circuit that uses a variable capacitor in parallel with the sample, as this appears to give us a reasonably stable circuit.

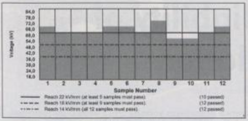

Fig. 3: Test No 1: Material 1, Cenelec.

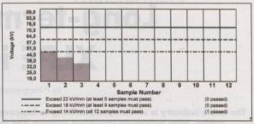

Fig. 7: Test No 9: Material 4, SABS.

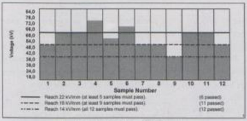

Fig. 4: Test No 4: Material 3, Cenelec.

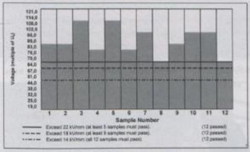

Fig. 5: Test No 7: Material 3, SABS.

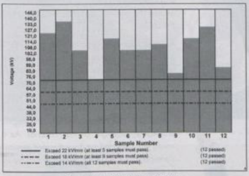

Fig. 6: Test No 8: Material 3, SABS.

The inverter consists of solid state components being driven reasonably hard. It is perhaps not too surprising that we have already blown up and replaced the equipment once.

Experience from Europe warned us of the possibility of Legionnaire's disease developing in our tanks. The disease is usually present naturally but the conditions in the tanks are conducive to it growing to a dangerous level. As a result we conduct regular tests and can confirm that the danger is real – we have had to shut down and disinfect a tank twice already.

Tests completed by Aberdare

We have so far completed seven tests, with five more under way. Of the completed tests three failed, giving us valuable information on certain materials and processes. The materials tested to date are summarised in Table 1, with specific results being given in the graphs that follow. Comments on the specific materials are:

Material 1: This is a standard material, which we tested to the Cenelec requirements (Test 1) as the test commenced before the SABS tests were published.

Material 2: This was a material that we tried because it had a distinct price advantage. This was perhaps reflected in the result as the material failed significantly and was therefore not used.

Material 3: We have used this material as a standard and will soon have completed both 50 Hz and 500 Hz tests on identical samples (Tests 3 and 8), providing data on the similarity of the tests. We have also used this material as an indicator of a process (Tests 7 and 8). Test 7 was carried out before we upgraded our material handling system and Test 8 was carried out after. Note that while each test was conducted on 12 sample sections, these were consecutive. In effect this means that for comparison purposes we have only one sample before the upgrade, and one after. While it is pleasing to see a significant improvement after the upgrade the sample sizes are too small to prove on their own that the upgrade was effective.

Material 4: This was development work on a new material and a new process. While the material has proved successful overseas, the test results showed that we would have to put considerable effort into the development of the process before it would produce successful cable.

Material 5: This is an alternative material that is being investigated at present. We are testing it at both 50 Hz and 500 Hz, which will give us alternative data to the data acquired with Material 3.

Materials 6 and 7: These are also alternative materials currently under investigation.

The results of the completed tests are presented on the graphs above.

Conclusion

As the result of problems experienced by some users of MV XLPE, both in South Africa and abroad, it became necessary to design and manufacture cable that would be resistant to the water tree mechanism of failure. It also became necessary to find ways of demonstrating that cable which had supposedly been designed and manufactured specifically with such resistance, actually achieved this promise. In South Africa this meant including accelerated ageing tests in our national standards.

As these standards are compulsory this, to some extent, should ensure that only cable that can pass the accelerated ageing type test will be sold and used in South Africa. Including these tests on local standards has also encouraged us to build our own test rigs and as a result we have found that the number of new materials we can now investigate with confidence has risen dramatically.

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Long-term reliability of XLPE insulation

by P Haripersad, CBI electric: African Cables

The cable industry is continuously striving to improve the performance of medium voltage cross-linked polyethylene cables. With polymeric insulation systems like this, the degradation of cable performance in wet conditions is still a major concern.

This degradation is attributed to the growth of water trees within the insulation. In October 2003, SANS 1339, the specification for MV cross-linked polyethylene (XLPE) cables became compulsory in South Africa [1]. In order to demonstrate the long-term reliability of the XLPE insulation and its resistance to the growth of water trees, it is imperative that customers demand that their cable supplier conducts either a two-year 50 Hz ageing test or a four-month 500 Hz ageing test before it can supply such cable on a commercial basis.

This paper focuses on CBI-electric: African Cables' successful completion of both tests. The results are discussed and effective comparisons made.

In South Africa MV cables are those cables operating in the voltage range from 3,3 kV up to and including 33 kV. The primary insulation is mainly impregnated paper or XLPE (see Fig. 1). The materials, design, construction and testing of these cables must comply with the national specifications, SANS 97 [2] and SANS 1339 [3] respectively.

The intentions of such compulsory specifications are to standardise the construction and to set prescribed requirements to ensure safety, good quality and long-term reliability of the cables. It is now compulsory [1] for all cable manufacturers supplying MV cable for installation in South Africa to ensure that their paper and/or XLPE cables are in strict accordance with these specifications. This is demonstrated by producing sufficient evidence of compliance, usually in the form of the latest type-test certification that is issued by a recognised independent and accredited body, such as SABS Netfa. It is therefore crucial for end customers like the utilities to request such information from manufacturers, at early tender stage, for assessment and evaluation before awarding valuable contracts.

Long-term reliability of XLPE cables

It is well known that the reliability of paper cables is high, with some paper cables still in service today after more than 50 years. However, a similar reliability was not reported for the first XLPE cables installed in Europe in the late 1970s and early 1980s. Premature insulation failures occurred and investigations [4] showed that these were mainly related to the presence of impurities or contaminants within the extruded XLPE insulation. Such contaminants within the insulation were common in the raw materials and were often also introduced during the cable manufacturing process.

With advancements in XLPE materials and production technologies over the years, both the cleanliness of the raw materials and the quality of the extruded insulation is today at a very high level, depending of course, on the cable manufacturer. The improvement in XLPE insulation is such that it is rapidly becoming the preferred insulation system for even the highest transmission voltages (500 kV). Compared to paper insulation, it also exhibits lower dielectric losses, higher operating temperatures and thus higher ampacities, and a lower impact on the environment.

Fig: 1 Typical MV paper insulated cables.

Fig 2: Typical MV XLPE insulated cables.

Generally, the service-life expectancy [5] of good quality, defect-free XLPE cables operating under normal conditions is estimated at 30 years-plus. Besides contaminants in the insulation causing electric stress field enhancements, there are other factors that can affect this long-term reliability. These include an increase in operating voltage (electric stress); increase in frequency; increase in operating temperature; and the presence of water trees.

Of these, the influence of temperature on long-term reliability of XLPE insulation is worth mentioning. It has been shown [5] that a 10°C increase in temperature from the normal 90°C operating temperature can reduce the cable service-life expectancy by about 50%. Therefore it is critical to rate cables correctly and measures should be taken not to constantly exceed the normal operating temperature of the cable.

Another important area of concern in XLPE cables that influences the long-term reliability is water tree growth within the insulation. Experiments on XLPE cables that had been in service for about eight years [4] concluded that the existence of several water trees within the insulation significantly reduced the electric breakdown strength of the material. As a result, this impacted on the estimated service-life expectancy of the cable, reducing it by up to 43%.

Water tree growth in XLPE cables

Practical experience and long-term tests on model cables [6] have shown that water has an adverse effect on XLPE insulation as it develops water trees within the insulation. Together with the presence of water, alternating electrical stress, temperature and a factor of time, water trees grow to such an extent that they 'bridge' the insulation, resulting in cable failure. Water trees are microscopic and usually




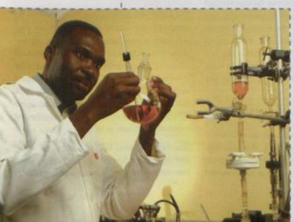

Fig. 3: A typical bow-tie tree in XLPE insulation

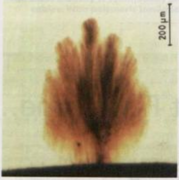

Fig. 4: A typical vented tree in XLPE insulation.

Fig. 5: CBI-electric: African Cables' 500 Hz ageing test lab and 500 Hz solid-state converter/inverter.

Fig. 6: Breakdown sites of the twelve 500 Hz aged MV XLPE cable core samples.

invisible to the naked eye, but with suitable dyeing techniques they can be stained and examined with a light microscope of adequate magnification. They are classified by descriptive words such as bow-tie trees and vented trees depending on their origin and shape. Typical examples are shown in Figs. 3 and 4.

The mechanism whereby water tree structures arise has not been clearly explained but the extensive work done by Cigré WG 21.11 has resulted in a list of several possibilities [7]. Generally, MV XLPE cables are not water blocked by design so water enters the insulation by diffusion. Due to contaminated raw materials, poor manufacturing processes or lack of adequate quality control, the presence of impurities or contaminants within the insulation will be high. Tiny water droplets concentrate around the contaminant within the insulation initiating a decomposing process that results in increased pressure around the contaminant area causing 'cracking' or water trees in the insulation. The subsequent vaporisation of these droplets during joule or dielectric heating further increases the pressure within the insulation extending these 'cracks' and causing them to grow.

Demonstration of long-term reliability – 50 Hz and 500 Hz ageing

In order to demonstrate the quality and long-term reliability of MV XLPE cable insulation, cable manufacturers are compelled to conduct an ageing test on their product. Currently as a type test requirement, SANS 1339 [3] allows the cable manufacturer to conduct either a two-year ageing test at normal frequency of 50Hz, 3 Uo (Uo is phase to earth voltage) or alternatively, an accelerated test at ten times the normal frequency (500 Hz), 3 Uo for 3000 hours (4 months). With such tests, the cable sample will simultaneously be subjected to the following three ageing mechanisms: high electrical stress due to increased operating voltage (3 Uo); frequency (50 Hz or 500 Hz); and growth of water trees.

The major attraction of a 500 Hz frequency is the shorter duration needed for the ageing. However, difficulties that may be experienced with a 500 Hz test and its apparatus are high equipment and development costs, poor reliability of operation, and lack of local testing availability. To date, only two South African companies are known to have 500 Hz ageing test facilities. Fig. 5 shows one such facility.

The assessment that needs to be conducted at the end of the ageing test, irrespective of frequency, is based only on electrical breakdown strength criteria. A water tree analysis or count of the number of water trees within the insulation is not a requirement for passing the test and is usually done for information purposes only.

A total of 12 samples that have been aged, each 10 m in active length, are subjected to a step breakdown voltage in steps of 1 Uo for five minutes, commencing from 3 Uo.The voltage at which each sample breaks down is recorded and according to SANS 1339, the passing criteria are as follows:

- all 12 samples must withstand a stress of at least 14 kV/mm
- nine out of 12 samples must withstand a stress of at least 18 kV/mm
- five out of 12 samples must withstand a stress of at least 22 kV/mm

CBI-Electric: African Cables decided to conduct ageing tests at both 50 Hz and at 500 Hz [10]. Besides conforming to all the type-test requirements of SANS 1339, this would enable the company to determine the level of quality and reliability of its extruded MV XLPE cables especially when subjected to these ageing mechanisms.

50 Hz and 500 Hz ageing test results and discussion

The specific method for preparing, conditioning and ageing cable samples at 50 Hz and at 500 Hz is well described in SABS test method SM1284-5 [11] and is not discussed in this paper. Only the results are listed and discussed. If more insight is required, reference can be made to a previous paper [10] written by the author.

Table 1 lists all the details and results of the two ageing tests that were conducted.

From the ageing assessment it is clear that all samples aged at 50 Hz and at 500 Hz (with the exception of one sample), had breakdown strengths in excess of 22 kV/mm (10 Uo). This satisfies even the highest withstand stress requirement in SANS 1339, where normally only five out of 12 samples are expected to achieve this. Figure 6.1 shows the short pieces of core cut near the breakdown sites of each sample aged at 500 Hz, in preparation for a water tree analysis.

The water tree analysis was conducted on all samples in the vicinity of the breakdown sites with both ageing mechanisms exhibiting few water trees. A total of 13 vented trees from all 12 samples aged at 50 Hz were found near the inner semi-conducting screen, with the largest vented tree measuring 600 μm in length. A total of two bow-tie trees were found in all 12 samples aged at 500 Hz, with the largest measuring 100 μm in length.

This however does not imply that the water tree ageing mechanism was inadequate since this method has already been well established and proven with several practical tests [6] [8]. The development of a few water trees is indeed a good indication that the quality of the manufactured cable core is in line with stringent quality standards and is relatively free from voids, defects and contaminants.

Reliability and life-expectancy of the 50 Hz and 500 Hz aged cables

The breakdown data has been further analysed using a statistical approach in the form of a Weibull Distribution [12]. Generally, it is a mathematical representation to cover reliability. By plotting all the data on a Weibull graph in terms of probability of failure vs. breakdown strength, it is much easier to project a straight line through most of the data points. This straight line enables the 63% characteristic breakdown strength, a 'mean value' for the data, to be determined which can then be compared to the breakdown strength of a relatively good and un-aged cable. The typical breakdown strength of an un-aged cable, at 11 kV, is approximately 50 kV/mm [13].

From the Weibull plots (Fig. 7), the 63% characteristic breakdown strength for the 50 Hz data was found to be 37,5 kV/mm and 32,5 kV/mm for the 500 Hz data. Due to the increased frequency and its effects on breakdown strength of insulation [8], it is common to expect a lower characteristic breakdown strength at 500 Hz (5 kV/mm lower in this case). Comparing the 63% characteristic breakdown strengths to 50 kV/mm, this equates to a 25% and 35% reduction in breakdown strength respectively. Since the quantity of water trees found was low, the reduction in breakdown strength can mainly be attributed to the increased electric stress (3 Uo) and frequency applied during the ageing process.

One method of relating the 63% characteristic breakdown stress to a cable life expectancy is by making use of an empirical relationship that expresses time to breakdown (t) as a function of the electric stress (E) of the material as shown in eqn. 1 [14].

$$t.\ E^n = C \qquad (1)$$

or in other words,

$$\text{Log}\ t + n.\ \text{Log}\ E = \text{Log}\ C \qquad (1)$$

where t is the life expectancy of the cable, E is the characteristic breakdown stress and C and n are constants of the insulation. For XLPE, n is at least 9.

By manipulating Eqn. 1, if the survival time t_1 at a stress E_1 is known, the life expectancy t_2 of the cable aged at a stress E_2 can be determined by Eqn. 2.

$$t_1 .\ E_1^{\,n} = t_2 .\ E_2^{\,n} \qquad (2)$$

Using the above relation, Fig. 8 shows a linear-log graph of cable life expectancy for the cable samples aged at 50 Hz for two years and at 500 Hz for approximately half a year. From the graph it can be seen that after 30 years of service life, the electric stress needed to break the cable samples down will still be very high, that is 12 Uo and 10 Uo respectively. When comparing this to the 1 Uo stress that the cable will normally operate at, one is reassured of the long-term reliability of the cable despite the three ageing mechanisms (electric stress, frequency, water trees) that have been applied simultaneously.

Discussion on the effectiveness of the two ageing tests

The ageing tests conducted at 50 Hz and 500 Hz both met the breakdown stress criteria of SANS 1339. However the differences in the results, although not very significant, do warrant some discussion. The first difference noted is the characteristic breakdown strength, with the 500 Hz value being 5 kV/mm lower than the 50 Hz value. Secondly, the slopes of the straight lines on the Weibull plot are not

	50 Hz, 2 years ageing	**500 Hz, 4 months ageing**
Cable details:		
Core description	6,35/11 kV; 95 mm² x 1 Al; s/c, XLPE, s/c; Cu tape screen	6,35/11 kV; 240 mm² x 1 Cu; s/c, XLPE, s/c; Cu tape screen
Diameter over inner semi-con (approximate)	13,5 mm	20,5 mm
Diameter over XLPE insulation (approximate)	20,5 mm	27,5 mm
Insulation thickness (approximate)	3,5 mm	3,5 mm
Calculated cable maximum stress at Uo (Uo = 6,35 kV)	2,3 kV/mm	2,1 kV/mm
Preconditioning details:		
Active core length	120 m	
Water	Normal tap water	
Duration	1000 hours	
Temperature	50°C ± 5°C	
Ageing details:		
Temperature	Room temperature (30°C ±5°C)	
Voltage applied	19 kV (3 Uo)	
Frequency	50 Hz	500 Hz
Duration	2 years (17 500 hours)	4 months (3000 hours)
Ageing assessment:		
Voltage step test	1 Uo (6,35 kV) for 5minutes starting from 3 Uo to breakdown	
Number of samples tested	12 samples of 10 m active length	
No. of samples withstanding 14 kV/mm (SANS 1339 requires all 12 to comply)	12	
No. of samples withstanding 18 kV/mm (SANS 1339 requires at least 9 to comply)	12	11
No. of samples withstanding 22 kV/mm (SANS 1339 requires at least 5 to comply)	12	11
Breakdown values:		
Voltage breakdown range	83 kV – 114 kV	70 kV – 121 kV (45 kV for 1 odd sample)
Maximum electric stress range	30 kV/mm – 41 kV/mm	23 kV/mm – 40 kV/mm
Weibull 63% characteristic breakdown stress	37,5 kV/mm - 32,5 kV/mm	
Water trees found at breakdown sites:		
Number of vented trees near inner semi-con	Total of 13 (≤ 600 μm)	0
Number of vented trees near outer semi-con	0	0
Number of bow-ties	0	2 (≤ 100 μm)

Table 1: Summary of the details and test results of the 50 Hz and 500 Hz ageing tests.

the same, with the 50 Hz line having a steeper slope than the 500 Hz line. Thirdly, the quantity of water trees developed at 50 Hz was more than the number of water trees developed at 500 Hz.

The above indicates that there are numerous ageing mechanisms taking place, some that are known and (no doubt), others that are unknown. The value of conducting both ageing tests therefore allows for a larger number of these ageing mechanisms to be stimulated.

By passing one ageing test, this qualifies a cable manufacturer in terms of the specification, but by passing both ageing tests, this gives much greater confidence on the long-term reliability of the manufactured XLPE cable.

Conclusions

This paper has highlighted the two different approaches that CBI-electric: African Cables has taken to demonstrate the long-term reliability of its MV XLPE cables. Cable samples were aged at 50 Hz and at 500 Hz with the main ageing mechanisms being increased electrical stress at 3 Uo, frequency and water tree growth. A comparison of the results of the two tests did not show significant differences.

Relating the 63% characteristic breakdown stress to a cable life-expectancy of 30 years, it was shown that by then, the cable samples would still have breakdown strengths in excess of 10 Uo. This is ten times more than the continuous operating stress (1 Uo) that the cable would normally be subjected too. This reinforces the long-term reliability of the insulation in terms of electric stress.

The water tree ageing mechanism produced very few water trees both at 50 Hz and at 500 Hz despite the energised cables being submerged in water for two years and four months respectively. This confirms the excellent quality of the manufactured cable and the extent of cleanliness of the insulation in terms of the absence of defects and contaminants.

The results of such ageing tests enable a customer to satisfy himself of the level of quality of the manufactured cable, its performance under increased electrical stress and frequency, and its ability to resist the growth of water trees. By successfully completing these tests and achieving excellent results, CBI-Electric: African Cables has demonstrated the high level of quality and the long-term reliability of its MV XLPE cables that it offers to the electricity distribution networks in South Africa.

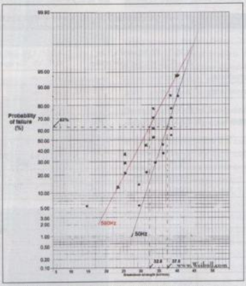

Fig. 7: Hand-drawn Weibull Plot of the probability of failure vs. breakdown stress.

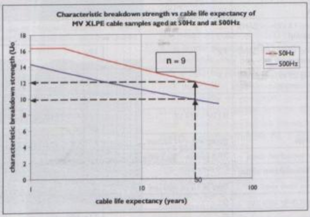

Fig. 8: Estimate of the cable life expectancy from the 63% characteristic breakdown strength of cable samples aged at 50 Hz and at 500 Hz.

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Improving reliability and revenue of distributed electricity

by Jean-Yves Pocthier, Schneider Electric, France

A direct consequence from population growth and related economic development at industrial, commercial and tertiary levels is an increasing demand for energy, including electricity. To fit that requirement, utilities need to produce more power.

They also need to improve their transmission and distribution networks as customers demand more energy reliability.

An increasing demand for energy

In countries with fast growing economies, MV distribution networks spread at such a speed that utilities and their employees need very efficient global solutions to decrease outage occurrences and duration, thereby improving the quality of service.

Depending on the technical solutions chosen, it is possible to help control revenue losses (non-distributed energy or non-technical losses). This paper describes the benefits of fault tracking and network reconfiguration that can help to achieve these goals.

Deregulation

Sooner or later, most utilities will face deregulation, which leads to various adaptations and new concepts of network operation. Even in countries where the deregulation process has not yet started, these concepts are applicable to improve the distributed electricity reliability and revenues.

Measuring the quality of service

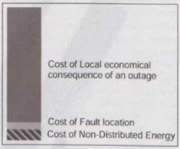
To reach the required level of quality of service, it is first necessary to accurately quantify it in a factual manner. To do so, utilities commonly use measurement indexes (sources: CEPSI 98, SEE 98):

- the "SAIDI" (system Average Interruption Duration Index) measures the average cumulated power outage time during one year,
- the "SAIDIp" (system Average Interruption Duration Index for only permanent outages) measures the average cumulated long outages (exceeding 1 min) during one year,
- the "SAIFI" (system Average Interruption Frequency Index) measures the average number of outages per year and per customer,
- the "SAIFIp" (system Average Interruption Frequency Index for only permanent outages) measures the average number of long outages per year and per customer,
- the "SAIFIsh" (system Average Interruption Frequency Index for only short outages) measures the average number of short outages (from15 to 30 s) per year and per customer.

When comparing the SAIDIp measured in the 1990s on the LV standpoint, we can see that this index varied from 16 min (RWE, Germany) down to 11h30 (Light, Brazil). For EDF France, it was 52 min in 1998. In few big well-supplied cities, the SAIDIp index varied from a few minutes to several dozen minutes (Rotterdam 1991: 9,3 min; Tokyo 1991: 11 min; Berlin 1991: 16 min; Copenhagen 1991: 25 min; London 1995: 54 min; and New York 1995: 1 min) but the SAIFIp index was often less than a unit (Rotterdam 1991: 0,12; Copenhagen 1991: 0,45; London 1995: 0,34). In France, the quality of service in the ten largest cities continually improved from 1990 to 1997 thanks to EDF investment efforts: in seven years the SAIDIp went from 2h down to 19 min, the SAIFIp from 2,2 down to 0,59 and the SAIFIsh from 2,3 down to 0,31. Last, but not least, if we look at the cause of faults, 25% come from the HV network, 25% from the LV network and 50% from the MV network.

The MV network is therefore the part of the whole network upon which the greatest care needs be taken to improve the quality of service.

Another variable to be taken into account in the quality of service is the cost estimation for non-distributed energy per year. It increases

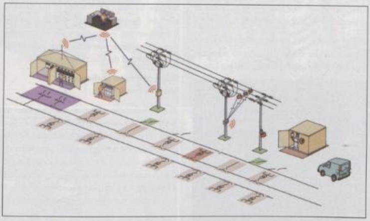


with the number of faults per year, the peak power demand, the length of distribution lines or cables that are connected to each feeder, the length of the outage, the billed price per kWh and above all the cost of consequences. This explains why this cost can vary from $5 to $30 per kWh ($7 to $10 according to TNB Malaysia).

The quality of service depends on the type and density of the population (rural or urban), the type of distribution (overhead or underground), and the effects and costs that were accepted as the consequence of an outage. The experience of many utilities shows that the quality of service can be improved when some technical solutions are applied on the electrical network itself: splitting the network into short sections, increasing its redundancy and implementing appropriate automation, increasing the dependability of network components and implementing remote control and fault detection devices.

Outages

The medium voltage (MV) network is the first part to take care of. Faults may come from both distribution lines as from underground cables. Underground networks are made of numerous MV/ MV and MV/ LV substations that are manually operated and difficult to access due to geographical constraints, distance or automobile traffic. They are affected by bad weather conditions (floods, etc.) and may offer a poor quality of service that translates into numerous long outages (SAIDIp varying from 2 to 10 h), high operating costs, and



safety problems for maintenance staff and consumers.

Overhead networks are often made up of long lines (radial lines from 10 to 100 km long), and are affected by harsh environmental conditions (sandstorms, rain, snow, quick temperature variations, industrial or natural pollution, etc.). The result may lead to poor efficiency and poor quality of service: numerous short breaks due to transient faults, long outages (SAIDIp from 3 to 15 h), considerable voltage drops, an overloaded network and considerable losses (from 10 to 15%, and even 20% losses).

Operating costs are often high as well whereas operators and the public can be subjected to safety problems. Each of the significant problems listed here (safety, voltage losses and drops, long outages, numerous short outages) can be solved taking appropriate actions on the MV network, such as protection and control-monitoring, reactive compensation, multiple sectionalising and use of appropriate fault detection tools.

Among these different problems, two of them, long outages and numerous short outages, can be solved using three types of solutions:

- Stand-alone fault passage indicators (FPIs).
- Remote controlled FPIs
- Automation and remote control systems

These solutions can be used separately but also in association – in this case some of the substations use remote control and/or automation capabilities while the other ones use FPIs. The choice between these two kinds of solutions is indeed a techno-economical choice. FPIs are a very economical solution to significantly improve the quality of service, while remote control systems, requiring bigger investment, allow for even bigger impact.

Pole mounted reclosers used in distribution lines are a very efficient solution to clear transient faults and to isolate faulty sections (for permanent faults), however no utility is rich enough to install them on every branch.

A global approach

The network management involves remote control functionality. MV distribution networks often have a tree structure mainly with overhead lines. The selection and placing of equipment and control systems in these networks requires careful planning to make the best of its performance. There are many possible ways (not exclusive) to place remote control points and FPIs on the network:

- retrofitting existing pole mounted or S/S switchgears with remote control, the difficult point being the motorising of the switchgear,
- installing FPIs on existing pole mounted or substation switchgear,
- creating new remote controlled points (pole mounted or S/S) corresponding to the available power growth in the MV network,
- creating remote controlled network points, fitted with current measurement capability to improve network dependability without increasing the available power
- anticipating the expansion of remote controlled points by systematically installing motorised MV switches.

The global approach concept aims to increase the efficiency of the network management, in terms of investment optimisation, reduction of minutes lost, reduction of customers concerned by loss of voltage and reduction of time to localise and reconfigure.

It involves a segmentation of the network into three levels. Three types of substations will split the distribution network into three types of sections.

Three types of substations

The fault loation and network reconfiguration scheme is defined from the use of three main types of substation:

- *Type 1:* S/S or pole mounted switch with stand-alone FPI
- *Type 2:* S/S or pole mounted switch fitted with remote controlled FPI
- *Type 3:* S/S or pole mounted switch fitted with a remote control cabinet including FPI function

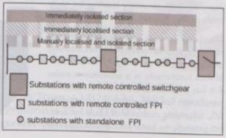
Three types of network sections

These three types of S/S split the network into three main sections:

- Small section edged by Type 1 substations
- Medium section edged by Type 2 substations
- Large section edged by Type 3 substations

Each of these sections may be characterised as follows:

- *The faulty large section can immediately be isolated by the remote control centre.* All customers in this section are not re-energised when the network is reconfigured: the larger the section, the bigger the number of customers with a long outage.
- *The faulty medium section is immediately localised at the control centre.* The maintenance crew is directly dispatched to the manually operated switch for opening. The result is that all customers in the healthy medium sections are supplied in a relatively short time.
- *The faulty small section needs the maintenance crew to patrol the network.* The time needed to reach the faulty section and to isolate it is rather long. Generally this section is as short as possible, and needs FPI function to be installed in each



substation (underground cables) or at each branch (overhead lines).

The most efficient scheme is to retrofit all S/S with a remote control unit, but this not an optimal situation in terms of economical approach. A trade-off is to mix the three types according to various criteria such as:

- Number of S/S on a feeder
- Number of customers in each section
- Importance of customers in each section (hospital, ministry, plant, etc.)
- Accessibility of the S/S
- Data communication facilities for remote indication
- Motorisation facilities in existing substations

According to the above considerations, a typical network feeder could be organised as follows:

- 1 to 3 S/S with full remote control
- 5 to 10 S/S with remote controlled FPI
- all other S/S with 1 FPI for all other S/S

A gradual solution

The concept of three main types of section provides the advantage of simplifying the investment analysis regarding the reality of the network. A network could be equipped gradually according to progressive investment capability.

A first step is to place a FPI in all underground S/S. The benefit is immediately visible in terms of time to locate faults, and also in terms of saving assets.

- FPI are easy to install on an existing network
- The localisation of the faulty section is done relatively swiftly by a patrol
- There is no need to reclose the feeding circuit breaker on the fault.

A second step is to install fully remote controlled S/S. This operation gives the benefit of quickly isolating the faulty section from the control centre. If the customer need is more important than accurately locating the faulty cable or line, this step should be done first.

The choice depends on the importance given to outage duration and number of customers affected by a loss of voltage. The installation of such functionality in a substation is easier if it has been defined before the substation installation for new networks. For existing S/S, adaptable control units could be used, but generally the better solution is to add new substations with remote control facilities at strategic points of the network.

In a third step, FPI connected to the control centre must be added in order to decrease the number of customers experiencing loss of voltage, by reducing the size of the isolated section. Another aspect to optimise the investment and increase the efficiency of the network management is to take care of the functionality of the electronic components.

OH: Clip on fault passage indicators.

UG: wall mounted FPI.

OH: Pole-mounted FPI.

UG: FPI embedded in the RMU panel.

Fault passage indicators: stand-alone FPIs

The fault detection function must be seen as a part of the network protection plan. So, depending on local specificity of line and cable distribution, the setting should be adapted for a better accuracy of the function. Consequently, the FPI function has to be fully programmable. Obviously, it is also a key economic factor as it allows stock management optimisation.

The FPI range should be used either on underground cable network or overhead lines (pole mounted or clip on the line). On underground cables, FPIs can be either wall-mounted on existing switchgears (RMUs or others) or delivered embedded in the RMU panel.

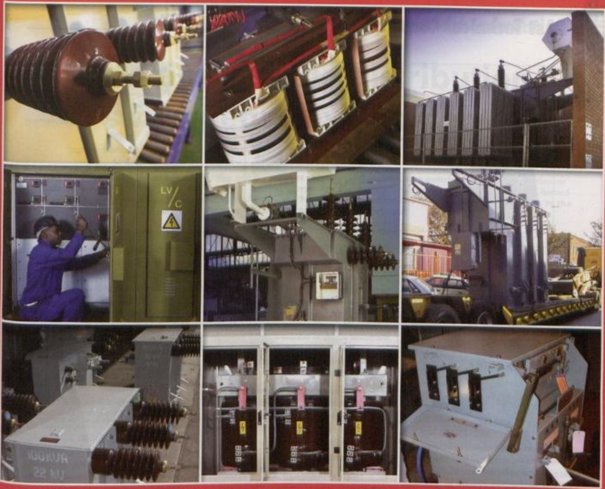
Overhead lines: clip-on FPIs

When utilities started to dream of getting the output of clip-on overhead FPIs (in case of network fault) directly at the SCADA, some manufacturers simply added a radio chip inside their existing clip-on FPI, that sent a short range radio signal to a radio receiver located on a direct line of sight, 10 m from it. This radio receiver was closing a contact upon fault occurrence and opening it upon MV return. The contact of the receiver was connected to a digital input of a small RTU that was forwarding the signal to the SCADA.

At first, this simple solution seemed to fill the need. However since then, users have discovered that this technical solution was inadequate as it lacked three main features:

- First, it was impossible to remotely test the short range radio link if a branch was growing in the path of the direct line of sight between the FPI and its receiver – resulting in the whole system not working any more.
- Second, when the battery was empty, the receiver could not be informed and so the SCADA operator would not get an alarm
- Third, given the fact that there is a remote communicating indicator installed, it should be possible to get a current measurement as well, in order to optimise the data communication costs (GPRS, etc.)

Some manufacturers have covered the gap, by offering more than what was initially required. By designing a system where the FPI and the receiver use a bi-directional



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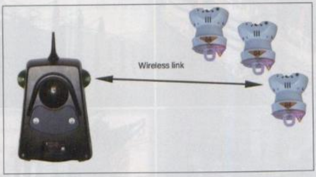

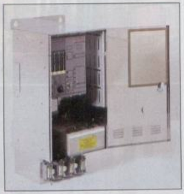

radio communication system, and where the receiver is based on a true RTU fitted with a data communication interface (RS232, GSM/GPRS), it has become possible to offer what was missing:

- Alarm upon wireless link (short range communication) failure
- Alarm upon battery low level
- Load measurement

Plus more:

- Remote FPI configuration (fault thresholds, etc.)
- More than three FPIs connected to a receiver.
- Time stamped recording of all events from FPIs and receiver

Pole mounted FPIs

Obviously such FPIs do not suffer the drawbacks of a wireless link: it is very easy to connect the dry contact output relay of a stand-alone FPI to a small RTU and report the alarm to the SCADA. However, it is not able to manage more than one MV line, even when located near a branch. The data communication system cannot report the information from the main trunk and the nearby branch: from a remote communication point of view, it is not optimised. In addition, it cannot measure the load on the phase conductors, so the link cannot be optimised in that aspect either.

Underground cables

In underground cables, the solution is even easier because there is no wireless link requested, the FPI is connected to three phase CTs. From a function point of view, it is a downsized version of a true remote control cabinet, with the difference that it does not have the power supply to actuate a switch motor (it offers current and power measurement, time-stamped events recording, remote parameter settings, etc.).

In order to simplify the communication function, it is recommended that remote controlled FPIs using a solution compatible with the remote control unit - (same protocol and same data communication media) be used.

Remote control

In a remote controlled S/S, electronic components have to perform the following functions:

- RTU: communication with control centre:
  - Storage and time-stamping for events and measurements
  - Support the range of protocols (IEC, DNP3, etc.)
  - Various data communication media (GPRS, GSM, PSTN, Radio.)
  - Local and remote configuration of all components of the control cabinet
  - Remote downloading of software updates and S/S configuration
  - Concentrating facility for existing IEDs (protection relay, power measurement devices, etc.)
  - Protocol communication tracing system (to find why the link to the SCADA does not work, in case that happens)
- Backed-up power supply for:
  - Switchgear motorisation
  - Modem
  - CPU
- FPI function including:
  - Direct acquisition from current transformers
  - Phase overcurrent and earth fault thresholds
  - Load and/or power measurement facility
  - Remote threshold settings
- Interface with the switchgear:
  - Ready to connect
  - Capacity from one to numerous feeders
- Local control and maintenance facilities.

Such a control cabinet may be built from standard components: however, the cost of such a solution is not cheaper than a specially designed control cabinet (ISCU or Integrated Substation Control Unit), and its reliability may be questioned. Given the impact of failed equipment on the network, fully tested units from complete control cabinet manufacturers are more attractive, as they guarantee:

- A safe installation.
- A simplified commissioning.
- A comprehensive maintenance.
- To be tested as a whole at the factory.
- The full EMC compatibility.
- Minimum wiring and cabling which dramatically increases the quality, the reliability and the availability of the control system.

Conclusion

It is now clear that in all developed countries, delivering electricity with high level of quality and availability has become a priority challenge. For years and years, the utilities have experimented with various solutions. It is now time to take advantage of all this experience. It appears clearly that remote control and fault detection are two of the key solutions. The customers are mainly affected by faults on the distribution MV network, to which, consequently, we have to pay a particular attention.

The introduction of fault detection and network monitoring and control needs to be driven with pragmatic and optimised actions. The cherry on the cake when using remote controlled FPIs and ISCU fitted with load measurement, is that utilities can easily optimise their power generation and chase non-technical losses. The global concept described here synthesises the experience acccumulated from various utilities world wide (France, Spain, UK, Australia, and Canada).

The components which must be associated with such a concept, for instance ISCU, remote controlled FPIs etc. are available on the market. Δ

Medium-voltage distribution switchgear developments

by R A Kelly, Eskom and M Ryan, City Power

This paper presents an argument for the use of medium voltage (MV) distribution switchgear – and in particular secondary switchgear (e.g. ring main units) – having alternative insulating/interrupting technologies to oil, based on safety, environmental and economic considerations. The paper also addresses recommendations relating to the management of existing oil-filled switchgear.

The use of medium voltage oil-filled switchgear is widespread in electricity networks in the South African electricity distribution industry (EDI). Although generally reliable, most switchgear installed before 1970 has reached the end of its design life and may be unsafe. Oil-filled switchgear, especially that which is either un-maintained, dependent manually-operated (DMO) and/or overstressed, can fail with catastrophic results for the operator, equipment, property and general public. The likelihood of failure increases with the age of the switchgear, inadequate maintenance, modifications not done in accordance with the manufacturer's recommendations and operation by inadequately trained operators. These factors are exacerbated by skilled and experienced staff leaving the EDI, either through natural attrition or migration to more lucrative positions in private industry.

Users have a duty, in terms of safety legislation (most notably the Occupational Health and Safety Act 85 of 1993) to their employees and the public to provide an acceptably safe environment and to take reasonable measures to mitigate against possible dangers. Since the risk described above may involve severe injury and/or death, the level of assessment and corrective action is required to be comprehensive.

Recent developments in distribution switchgear technologies have presented end users with a compelling argument for the use of lower cost, safer and more reliable equipment. This includes the use of switchgear having an insulating/interrupting medium of gas, air, vacuum and/or solid dielectric that is 'sealed for life' – requiring minimal maintenance and intervention over its lifetime. With developments in both technology and knowledge, it is now possible to use safer switchgear that is fully tested not only to withstand the effects of, but to safely 'vent' the emissions generated by, an internal (arc) fault.

Definitions and abbreviations

Anti-reflex handle: a one-way operating device that must be removed and relocated before performing another switching operation, thus preventing an operator from attempting to reverse an incorrect operation.

DMO (dependent manual operation): an operation solely by means of directly applied manual energy such that the speed and force of the operation are dependent upon the action of the operator.

Overstressed: a situation arising when the prospective fault current of the electrical system at the switchgear location exceeds the fault current rating of the switchgear.

History of medium voltage switchgear in the South African electricity distribution industry (EDI)

Oil-filled switchgear

For many years, the primary insulating and interrupting medium for MV switchgear was oil and a significant portion of the installed medium voltage switchgear base in the SA EDI is classified as oil-filled. Although, the scope of this paper primarily addresses oil-filled secondary switchgear (e.g. ring main units (RMUs)) – many of the issues addressed are also applicable to primary oil-filled switchgear and users are encouraged to apply similar principles to any base of installed oil-filled switchgear which they may have.

In the more recent years, an alarming trend has surfaced, i.e. that oil-filled switchgear is not being adequately maintained. If maintenance is being carried out, in many cases it is not in accordance with the requirements of the original equipment manufacturer (OEM). Historically, most switchgear has been maintained on an interval- and event-based maintenance schedule. In some cases, a 'run to failure' philosophy has been adopted i.e. as if this was considered an acceptable option irrespective of the risk involved.

Most oil-filled secondary switchgear (i.e. RMUs) is classified as 'free-breathing' and therefore prone to moisture and pollutants resulting in what is referred to as an 'uncontrolled environment'. In order to obtain access to the oil, the switchgear must be isolated and earthed in terms of operating regulations before any maintenance can be performed. Due to ever-increasing quality of supply expectations from customers, it is becoming increasingly difficult to schedule the onerous outages required.

In certain instances, maintenance is simply not being scheduled, often as a result of pressure on maintenance budgets. The above factors have all lead to an all too common trend that the required maintenance is not being performed on aging switchgear. This leads to a gradual deterioration of the insulating, and in particular, the interrupting properties of the oil. The probability of mechanism failure in an 'uncontrolled environment' also increases through lack of maintenance. As a direct result, numerous switchgear failures have occurred which have been accompanied, in many instances, by serious injuries, and in some more severe cases, fatalities. The overall risk of failure increases with the age of the inadequately maintained switchgear.

Clause 5 of the British national Health and Safety Executive (HSE) document 483/27 'Oil-filled electrical distribution and other switchgear' [1] states, "In general, oil-filled switchgear has a proven record of reliability and performance. Failures are rare but, where they occur, the results may be catastrophic. Tanks may rupture, resulting in the ejection of burning oil and gas clouds, causing death or serious injury to persons and major damage to plant and buildings in the vicinity of the failed equipment. Accident experience has shown that failure usually occurs at, or shortly after, operation of the equipment. Thus, the way switchgear is operated, its condition and the circumstances existing in the system at the time of operation, to a large extent, determines whether the equipment will safely perform its duty."

A number of failures have also occurred as a direct result of sub-standard oil-type MV HRC fuses used in switch-fuse combinations. Users are cautioned regarding the serious risk associated with the use of inferior quality and/

or non type tested fuses that have entered the South African market in the past. Tests carried out on such fuses by Eskom Distribution at the SABS national electrical test facility (Netfa) have proven that they are unable to interrupt current up to their rated capacity and in fact have exploded at current magnitudes of only 10 kA (i.e. < 25% of the rated interrupting capacity). This, coupled with the fact that oil-filled switchgear is not internal arc rated, presents a potentially fatal hazard to operators and the general public in the event of the fuse attempting to interrupt a downstream short circuit. In the Western Cape, an Eskom employee was fatally injured as a result of such a fuse. In addition, these fuses do not provide adequate 'oil-tight' seals to prevent the ingress of oil into the fuse.

Other insulating mediums

The use of cast epoxy resin as an insulating medium (often in combination with free air) is also fairly widespread in what is called MV 'insulation-enclosed' switchgear where all the conductors are completely embedded in insulation material (except for the external connections). Users are encouraged to apply the principles given in this paper to existing insulation-enclosed switchgear as many of the failures experienced are also due to inadequate maintenance, adverse service (environmental) conditions and even inadequate operator training/experience.

Air-filled enclosures (of the 'free-breathing' or 'free-air' type) have been and are still widely used today, for example in indoor metal-enclosed ('metal-clad') switchgear (e.g. busbar enclosures, cable termination enclosures, etc.) and outdoor switchgear (e.g. cable termination enclosures of RMUs). Air-filled switchgear enclosures are certainly not exempt from having a relatively poor track record in South Africa. Suffice it to say that many of the problems experienced in the past with switchgear having 'air-filled' enclosures can be overcome by correctly applying the minimum insulation requirements specified in NRS 012 [2]. Users should be aware of the four types of cable terminations and live conductors defined in this specification when specifying and purchasing switchgear. Users are also cautioned regarding the wide-spread misconception that pollution conditions within a brick-built room (or even an outdoor enclosure) are necessarily of lesser concern when compared to an outdoors environment. Polluted indoor insulation surfaces do not have the benefit of being washed by rain and therefore may require periodic cleaning – especially if creepage distances are insufficient. It is well known that installations in the South African environment experience large cyclic temperature fluctuations over a 24 hour period – accompanied by relatively high amounts of condensation – resulting in the 'wetting' (not washing) of polluted surfaces. This scenario only exacerbates any leakage current and/or surface tracking activity and subsequent probability of failure. Only if adequate measures are taken to air-condition the room, filter the incoming air and develop a positive pressure within the room can the pollution and condensation problems be reduced.

Irrespective of the switchgear primary insulation medium, it is acknowledged that many of the failures can be traced back to the cable terminations. It is the authors' opinion that only through the coordinated enforcing of insulation requirements as given in NRS 012 for air-filled enclosures can these problems be adequately addressed. Many failures can be attributed to an uncoordinated transition from compound filled boxes to the use of modern dry-type accessories in air (e.g. heat/cold shrink, slip-on or other cold applied technologies) without due consideration for the termination enclosure insulation coordination requirements. Amongst others, NRS 012 addresses minimum requirements for clearances, creepage distances, pre-defined cable termination bushings and insulators. Cable accessories in accordance with NRS 053 [3] should then be used – providing a complete integrated solution for the switchgear-cable interface.

Fig. 1: – Examples of switchgear failures due to an internal arc fault in oil.

Alternative solutions to oil-filled switchgear

Prior to the advent of suitable alternatives to oil-filled switchgear (e.g. gas-insulated metal-enclosed switchgear), requirements such as internal arc classification could not be seriously considered. At best, oil-filled switchgear having internal arc tested air-filled cable termination enclosures may be available. The concept of internal arc testing has emerged in the process of addressing the safety concerns around increasing switchgear failure risks. The now well known concept of internal arc classification (IAC) involves designing and testing equipment that, should an internal short circuit fault (arc) occur in any of the switchgear enclosures, it will fail in a controlled, 'safe' and predictable manner. The nature of an internal arc fault in oil (i.e. between live parts not designed to interrupt current), is deemed to be uncontrollable. Explosion vents, if provided, would simply allow burning oil and vapour (at temperatures of a few thousand degrees Celsius) to spew into the surrounding atmosphere – resulting in significant damage to property and people. As a result, it is simply not possible or practical to internally arc test oil-filled switchgear. Fig. 1 shows an example of a failure due to an internal arc fault in oil-filled switchgear. In contrast, internal arcs faults in air-filled and gas-insulated switchgear are classified as 'dry-arcs'. 'Dry-arcs' can be simulated in a test laboratory and therefore suitable methods developed to contain and/or safely vent the emissions (including conductive vapour and molten metal) created during an internal arc fault.

Sulphur hexafluoride (SF6) has proven itself to be a preferred gas for filling enclosures – for example busbar compartments housing live equipment in compact switchgear. SF6 is a relatively new development in comparison with the other technologies and offers superior performance in terms of insulation and arc extinction. It is electronegative (i.e. it absorbs free electrons) making it an excellent medium for arc quenching because it absorbs the free electrons produced in an arc. It has a dielectric strength three times that of air at atmospheric pressure and the dielectric strength rapidly increases with increasing pressure. Its arc extinction properties are three to four times superior to that of air at the same pressure. The gas is odourless, non-toxic, chemically inert, and non-flammable. Nevertheless, it is classified as a greenhouse gas and fairly stringent procedures have to be complied with to recover, store and recycle SF6. In addition, the gas is denser (and hence heavier) than air and it therefore has a tendency to collect in low-lying places e.g. basements in the event of it escaping. Since it displaces air, in

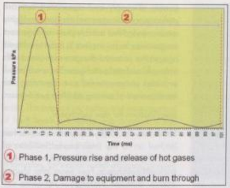

Fig. 2: Typical pressure rise in switchgear.

sufficient concentration it may be hazardous as it is non-life-supporting. The gas is under positive pressure to prevent the ingress of any air or moisture. Gas loss is typically less than 1% per annum and this is taken into account by manufacturers at the time of filling. The expected service life before maintenance/re-filling of an SF6 switch is up to 30 years. Arcing does cause decomposition of the gas, but in very small amounts. The products of decomposition are toxic and react with water, but since the tanks are sealed and filtered neither of these issues present a problem. Note that for high voltage (>33 kV) GIS switchgear, SF6 is the most prevalent insulating and interrupting medium available and used.

It is worth noting that oil, when used purely as an insulating and/or cooling medium (e.g. in conventional power transformers), is not considered to present the same safety risk to the user. The principle of operation of a transformer (i.e. mutual induction) is different to that of oil-filled switchgear, where contact separation through moving parts occurs in the oil. The drawing of an electrical arc within oil and in particular contaminated oil between conductive parts not designed to interrupt current (i.e. under conditions of a short circuit internal arc) results in the rapid expansion of the oil and vaporisation of moisture in an uncontrolled and explosive manner as described above.

Safety considerations

Risk

Safety is achieved by reducing risk to a tolerable level. Tolerable risk is determined by the search for an optimal balance between the ideal of absolute safety and the demands to be met by a product, process or service, and factors such as benefit to the user, suitability for purpose, cost effectiveness, and conventions of the society concerned. 'Risk' is considered to be the combination of the probability of occurrence of a harm and the severity of the harm [4]. It follows that there is a need to continually review the tolerable level of risk – in particular when developments in both technology and knowledge can lead to economically feasible improvements – in order to greatly reduce the risk associated with the use of a product, process or service.

Internal arc

In essence, an internal arc is a short circuit between components having different electrical potentials within a chamber filled with a particular insulating medium. It is an uncontrolled conduction of electrical current from phase to earth and/or phase to phase accompanied by ionization of the surrounding medium (e.g. air/SF6). Because of the expansive vaporization of conductive metal, a line-to-line or line-to-ground arcing fault can escalate into a three phase arcing fault in less than 1 ms. Arc energy is a function of system voltage, short circuit current, and the time until the upstream protection operates. Voltage is a function of system design, current is a function of system design and operation. Arc time is a function of protective device response. The heat energy and intense light at the point of the arc is called an arc flash. Arc flash energy absorbed by a person is a function of arc energy, distance from arc and personal protective equipment (where applicable). An internal arc is accompanied by a rapid rise in pressure followed by a burn-through period as indicated in Fig. 2. In the absence of suitable pressure release mechanisms (e.g. 'venting ducts or flaps'), arc faults are extremely dangerous and potentially fatal as temperatures at the arc can reach four times the temperature of the sun's surface. The high arc temperature vaporises the conductors in an explosive change in state from solid to vapour. Copper vapour expands to 67 000 times the volume of solid copper. Fig. 3 shows an example of the release of arc flash energy where inadequate pressure release mechanisms were provided. However, through the specification and design of internal arc classified switchgear, where the energy and emissions resulting from and internal arc are suitably vented away from the operator and/or people in the vicinity, the 'safe' working distance can be effectively reduced.

Fig. 3a Enclosure prior to test.

Fig. 3b Resulting arc flash.

The most common causes of an internal arc fault are:

- Insulation defects due to quality deterioration of the components (including oil). The causes can, for example, be adverse environmental conditions, a highly polluted environment and lack of maintenance;
- Overvoltages of atmospheric origin or generated by operation of a component (inadequate insulation co-ordination);
- Incorrect operations due to not respecting the procedures or to inadequate training of the personnel in charge of the installation. Note however that when evaluating switchgear performance, it is important to distinguish between limitations placed on equipment by design and by operating procedures. For example, the ring switches of an RMU are designed as load-break, fault make devices. Failure of the switchgear to perform these functions cannot be excused despite any restrictive local operating procedures;
- Breakage or tampering of the safety interlocks;
- Overheating of the contact area, due to the presence of corrosive agents or when the connections are not sufficiently tightened;
- Entry of vermin into the switchgear live compartments;
- Material left behind inside the switchboard during maintenance operations;
- Interference with cable terminations during cable testing. This can be eliminated through the specification of integral cable test facilities that are independent of the cable termination enclosures (eliminating the need to access and interfere with the cable terminations);
- Use of inferior quality and/or non type-tested MV HRC fuses (see below); and
- Incorrect installation (e.g. striker pin facing wrong direction) and/or replacement of MV HRC fuses (i.e. all three fuses of the same make and rating not replaced at the same time after a fuse operation – see below).

Risk reduction

The basic philosophy adopted for risk reduction can be summarised as shown in Fig. 4. It is important to note that, as always, personal protective equipment (PPE) should be considered as a last line of defence, and not as a replacement for appropriate equipment design and testing (e.g. internal arc compliance), safe work practices or engineering controls that can help limit exposure to arc-flash hazards.

In South Africa, the Occupational Health and Safety Act (OHS Act) [5] has a general duty clause requiring employers to take reasonable precautions to ensure their employees' health and safety. Although it is not the primary objective of this paper to discuss the relevant safe working practices and appropriate personal protective equipment (PPE), due to the fact that there are currently no local electrical safety regulations relating to internal arc, users are encouraged to refer to the recommendations given in the National Fire Prevention Association document 'Standard for Electrical Safety in the Workplace' (NFPA 70E) [6, 7] adopted by the U.S. Department of Labour, which, in short, requires that:

- 'Limited approach', 'restricted approach', 'prohibited approach' and 'flash protection' boundaries need to be established in order to assure that personnel do not accidentally contact exposed, energized electrical equipment.
- Employees are aware of potential hazards when operating, changing the position of, or working in the proximity of energized electrical equipment.
- If an employee needs to enter a flash boundary to perform work that could possibly cause an arc flash, then appropriate PPE (personal protective equipment) needs to be worn.
- The type of PPE depends on the amount of energy to which an employee could be exposed.

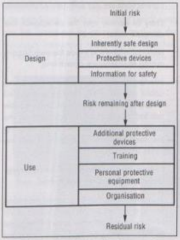

Fig. 4: Risk reduction

This would require an arc flash hazard analysis (risk assessment) to be carried out in order to determine the type of PPE needed for the arc energy level, the duration of the arc flash and the working distance (degree of exposure or impact). For new equipment, it is possible to significantly limit the probability and impact of an internal arc – by providing switchgear that is specified and tested with a suitable internal arc classification (see below). An implication of having internal arc classified (IAC) switchgear in accordance with SANS/IEC is that the clothing category of PPE required would be entry level, i.e. a single layer of untreated natural fibre clothing without any arc rating ('cal/cm^2'). Note however that SANS 62271-200 states that classification IAC gives a tested level of protection of persons under normal operating conditions as defined in annex A.1 of SANS 62271-200 (i.e. including manual operating and monitoring of switchgear at normal working distances). It is concerned with personnel protection under these conditions and not under maintenance conditions nor with service continuity. The latter would require additional safety measures to be taken. Here, requirements such as having metallic partitioning (PM) between enclosures and specifying an appropriate loss of service continuity (LSC) classification in accordance with SANS 62271-200 become relevant.

It is often beneficial to look into the introduction of other possible 'supplementary' measures such as internal arc detection for rapid fault clearance, current limiting devices (e.g. HRC fuses in combination with switching devices), 'arc eliminators/suppressors', remote control, motorised racking devices, pressure relief devices, and the transfer of withdrawable parts to or from their service positions only when the front doors are closed. A co-ordinated philosophy is required when approaching the subject of internal arc classification and specifying new equipment and safety measures. Users are cautioned that 'blindly' specifying combinations of various measures aimed at reducing the probability and impact of an internal arc can lead to unnecessary or wasteful expenditure. However, whether working with new or older equipment, the requirements of NFPA 70E and the OHS Act should always be considered.

In situations where elevated risks still exist (such as in the case of un-maintained oil-insulated switchgear), the only practical way to eliminate an internal arc flash risk is to remotely de-energize the electrical circuit(s) when the equipment is being operated, if it is going to be prepared for maintenance or inspection as well as when equipment is being returned to service following an interruption. However, such a decision has a significant impact on quality of supply and associated network performance indicators and it is therefore highly recommended that suitable plant management programmes be put in place in order to mitigate against the potential dangers associated with older oil-insulated switchgear. Section 8 below provides recommendations regarding the management of existing oil-filled switchgear.

Specifications for new switchgear

Since January 1998, Eskom Distribution has latched on to the international initiative of internal arc testing of indoor primary metal-enclosed switchgear. Four years later (August 2002), outdoor switchgear followed suit when internal arc rated compact secondary switchgear was specified and purchased for sub-switching stations (i.e. RMUs) and 'Type B' mini-subs (i.e. equipped with a RMU) – typically found downstream of primary switchgear. Operator and public safety has been put under the spotlight in the past few years following catastrophic failures of metal-enclosed and outdoor oil-insulated RMU switchgear – elevating arc flash safety and hazards to new levels. This has forced Eskom and other utilities to review the current design standards from a product compliance, testing and application perspective.

Eskom and other major utilities have recently been involved in the development and re-testing of switchgear products to meet the safety requirements of the Occupational Health and Safety Act and industry-aligned requirements utilising the recently published SANS 62271-200 [8] as well as SANS 61330 [9] (due to be replaced by SANS/IEC 62271-202) as reference.

The applicable specifications for distribution switchgear require that they be type tested to ensure the safe release of gases in the event of an internal arc fault – giving them an internal arc classification (IAC) in accordance with the relevant SANS specifications. This has been made possible due to the specification and purchasing of air-filled and/or gas-insulated switchgear. The SANS specifications for internal arc testing (detailed in annexures A of SANS 62271-200 for metal enclosed switchgear and SANS 61330 for prefabricated substations) cater for two relevant categories of internal arc classification – based on the type of accessibility required by the user. Type A accessibility is restricted to authorised personnel only and Type B accessibility caters for unrestricted accessibility – including that of the general public. Different types of accessibility may be applied to various sides of the switchgear / enclosure – i.e. front [F], lateral [L], and rear [R]. Each accessibility type requires specific test conditions designed to simulate the actual conditions on site. The philosophy applied by

Eskom Distribution for specifying the internal arc classification for switchgear is based on the maximum prospective fault level applicable to the relevant part of the network, the protection philosophy relevant to the type of switchgear. If necessary, current limiting devices (e.g. air-core reactors) may be required to limit the prospective fault levels to within the pre-defined limits. The internal arc rating and management of fault levels are taken into account in the planning and design of electrical networks in Eskom Distribution [10].

In summary, for indoor metal-enclosed primary switchgear ('metal-clad'), the following is specified by Eskom Distribution:

Classification IAC:
AR-BFL (SANS 62271-200)

Internal arc:
25 kA 0,2 s (for 12 kV and 24 kV);

Although the switchgear is generally housed indoors in a brick-built switch room, the rear of the switchgear is restricted to authorised personnel only, whereas the sides and front provide what Eskom regards as unrestricted accessibility (e.g. taking into consideration the possibility of having personnel indoors that are not classified as 'responsible' or 'authorised' in terms of the Eskom operating regulations for high voltage systems). The 0,2 s arc duration is based on the fact that internal arc detection systems are specified for indoor switchboards. These internal arc bus protection schemes employ detectors sensitive to light that are installed in all switchgear enclosures to act as fast sensing devices in the event of an arc. They are designed to initiate an upstream circuit breaker trip in less than 0,1 s. Arc venting is required to be upwards (without exhausting ducts) and the key switch room dimensions are standardised to coincide with the internal arc test requirements. The switch room is also designed for pressure relief.

For outdoor secondary switchgear (e.g. RMUs and miniature substations usually installed downstream of indoor metal-clad primary switchgear), the following is specified:

Classification IAC:
AF-BFLR (SANS 61330) or 'AB' (proposed SANS/IEC 62271-202)

Internal arc:
20 kA 0,5 s (for 12 kV); 16 kA 0,5 s (for 24 kV)

Outdoor switchgear is normally installed in areas of general public accessibility – requiring type B accessibility on all sides (with all doors closed). In addition, with the front MV doors open (front access only), type A accessibility is required for the operator. The 0,5 s arc duration is based on the upstream protection settings typically applied for grading considerations. No

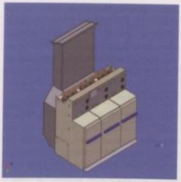

Fig. 5: RMU with internal arc venting duct for IAC AF-BFLR.

internal arc detection systems are employed. As this outdoor switchgear is usually installed on solid concrete plinths (usually pre-cast) with cable trenches that are backfilled and sealed (using a concrete screed), venting of the switchgear can only be directed upwards – requiring a 2 m high arc venting duct – an example of which is shown in Fig. 5. The duct/venting system is designed and tested to vent emissions resulting from an internal arc fault in any of the gas and/or air-filled enclosures within the switchgear (i.e. a common venting system for the SF6-insulated busbar enclosure and the air-filled cable boxes). Such a duct system can be applied to free-standing RMUs as well as RMUs installed within miniature substation. The proposed IEC 62271-202 makes special provision for the MV interconnections (jumper cables) between the RMU T-off and the MV/LV transformer. The enclosure/compartment housing the interconnections may be excluded from the internally arc tested zone either by specifying a (fast operating) HRC fuse (i.e. fuse-switch combination) in the RMU T-off or, if a circuit breaker is specified, by using fully screened cable jumpers and separable connectors onto the transformer.

It is the view of the authors that the introduction of mandatory type testing for internal arc classified (IAC) switchgear and controlgear as detailed in SANS 62271-200 and SANS 61330, together with the implementation of safe working practices (such as those detailed in NFPA 70E), has greatly enhanced the employer's ability to specify acceptable equipment that significantly improves both operator and public safety.

In addition, with the availability of switchgear requiring minimal maintenance intervention (e.g. circuit breakers of class 'E2-M2' in accordance with SANS 62271-100 [11]), fixed pattern metal-enclosed primary switchgear (normally 'partially' gas-insulated) can be considered in future – as an alternative to the more traditional withdrawable 'metal-clad' switchgear.

Economic considerations

It is well accepted that any sound engineering solution must take into consideration the total cost of ownership during the expected life-span of the design alternatives. This involves carrying out a comprehensive 'life-cycle costing' study – comparing alternatives available to the engineer from an economical point of view. Ultimately, all engineering alternatives can be compared in terms of economics – taking into consideration all the identified and quantified risks.

Life cycle costing can be approached in several ways but the fundamental principles are the same in each case. The factors considered important and the weighting given to them will have a significant impact on the result. The following factors are considered to be the most important and should be taken into consideration in the comparison of various planning variants:

- Initial capital cost (cost of acquisition)
- Future upgrade/replacement costs
- Cost of technical losses
- Cost of unserved energy
- Maintenance costs (normally periodic)
- Dismantling / residual costs
- Liability costs
- Operating costs

Included here is the ever increasingly important cost of 'un-served energy' (COUE) or the cost that the customer incurs due to plant interruption during an outage, whether planned or un-planned. This is in effect the cost to the economy of a power outage. The COUE is based on the class of customer being supplied. Table 1 shows the costs of unserved energy for the different customer classes used by Eskom [10] (2005 figures shown). Note that one of the realities experienced in Eskom and other major utilities is that there are few areas that are made up of one single class of customers.

It is often the case that there is a mixture of, for example, commercial and residential customers. Many light commercial businesses are now operated from homes that would normally have been classed as residential. In such areas, a R/kWh value is to be determined that is representative of the mix of customer classes in the particular area.

In 2002, Eskom carried out a comprehensive life-cycle costing comparison between oil-filled and gas-filled (i.e. SF6) RMUs and then again in 2004 using the Electric Power Research Institute (EPRI) Life-Cycle Cost Management System (LCCMS) and Life-Cycle Decision Making (LCDM) software. The results from

Customer class	R/kWh
Industrial/mining	20,47
Commercial	15,95
Agricultural/rural	2,80
Residential	2,38
Traction	1,26

Table 1: Costs of unserved energy (average customer interruption cost) – 2005 Rands [Eskom].

both studies were consistent – indicating overwhelming support for the use of SF6-insulated switchgear. For the purposes of this paper, the results of the more recent (2004) study [12] are summarised below.

The two alternatives evaluated were:

- Oil-insulated switchgear that undergoes routine maintenance every three years (minimum). Note that the assumed maintenance frequency and average cost of maintenance were based upon Eskom experience with the installed base of oil-insulated compact switchgear;
- SF6 gas-insulated switchgear that is considered to be maintenance-free and requires no intervention requiring a prolonged outage.

The two alternatives were analysed for the acquisition, use and disposal phases of their life-cycle and the results are shown in Fig. 6. The two most significant cost elements that make up the "use" cost factor for oil-insulated switchgear are:

- The 3 yearly maintenance cost; and
- Cost of unserved energy that occurs while doing maintenance.

A number of the key differences giving rise to the results shown in Fig. 4 (between oil-insulated and SF6 insulated switchgear) are now briefly discussed.

The purchase price ('acquisition') of an SF6-insulated RMU is (to-date) higher than that of an oil-insulated RMU. These prices are effectively determined by market dynamics. However, it is worth noting that the commercially available SF6 switchgear used by Eskom and other utilities is manufactured to more stringent international specifications (e.g. internal arc classification and other specifications given below). It is also worth noting that the difference in cost has been decreasing over the last number of years.

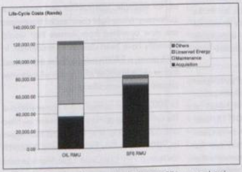

Fig. 6: Total cost of ownership of oil versus SF6 gas-insulated switchgear (2004 Eskom study).

Most modern SF6 equipment is marketed as being 'maintenance free' due to the fact that they are considered to be 'sealed for life' and thus environmentally controlled. In comparison to the amount of maintenance required for oil equipment, this is a fair statement to make. It was assumed that the operational life of the equipment is 25 years as recommended by the major manufacturers.

The SF6 insulating medium has a very long service life, far in excess of the RMU itself, whereas the oil's dielectric strength deteriorates over time and so requires regular checking – especially considering the fact that oil-filled enclosures are 'free-breathing' to the outside environment. Maintenance on oil units implies an 8 hour outage which is required every 3 years, whereas maintenance of SF6 units is scheduled for once every 12 years which involves a 4 hour outage.

The latter includes visual inspections, basic operating mechanism maintenance and if necessary the cleaning of the cable termination enclosures (due to vermin and other possible environmental pollution). No maintenance is required within the SF6 chamber housing the switchgear itself as this chamber is regarded as a 'non-accessible compartment' in accordance with SANS 62271-200. Note that despite the assumption that 20% of the outages can be scheduled over weekends with little impact on business, the maintenance outages result in significant costs to businesses due to unserved energy. Of course any interruption, whether planned or un-planned negatively affects customer relations.

Unlike SF6-insulated equipment, oil-filled equipment is delivered devoid of its insulating medium. In addition, the oil has to be replaced or recycled usually 3 – 5 times during its life. This also implies down time, labour, transport and specialised tools such as oil filtration plants. This incurs additional logistical considerations involving filling the switchgear with oil, testing and de-tanking. The storage of the oil raises other concerns as aside from the sheer bulk and movement of the oil drums, they have to be stored in a particular manner. They cannot simply be left standing upright in their 'natural' state, as the breather valve on the lid of the drum would draw in water and contaminate the oil – impairing its dielectric strength. The drums are required to be stored in a demarcated area in a horizontal manner and must further be kept on a raised surface – preferably undercover to avoid large temperature fluctuations. Using SF6 insulated equipment in place of oil can also result in simplified installation and commissioning procedures. In particular, the installation time of SF6 equipment is inherently shorter due to the fact that the oil-filled RMU has to be filled with oil on site. Filling of outdoor RMUs with oil introduces other risks due to the possible contamination of the unit whilst open. These factors associated with oil-insulated equipment all contribute to both direct and indirect costs – which are not an issue with 'sealed-for-life' and factory tested SF6 insulated equipment. Manufacturers of SF6 switchgear also offer free end-of-life equipment disposal services – based on acceptable environmental considerations.

Notwithstanding the safety aspects, the economic outcome is significant and clearly in favour of the gas-insulated 'sealed-for-life' technology (e.g. SF6). Note that at 22 kV and above, there is no option but to use SF6 gas-insulated RMUs as no suitable alternative currently exists.

Other considerations and benefits

Other benefits, in addition to those mentioned above, of modern compact gas-insulated RMUs complying with the specified user requirements include:

- Cable termination enclosures and operating facilities that are accessible from the front providing practical (cost saving) benefits when achieving the required internal arc classification and the ability to standardise on a footprint and hence introduce pre-cast concrete plinths having a common design and dimensions;
- Full switchgear interlocking facilities (including all cable termination enclosures)eliminating undesired switching sequences and/or unsafe situations;
- Independent manual operation with anti-reflex provision;
- The option of specifying a circuit breaker (as opposed to a switch-fuse combination) having an class C2-E2-M1 (i.e. vacuum or SF6) in accordance with SANS 62271-100 (as opposed with a switch-fuse combination), providing appropriate electrical and mechanical endurance without requiring internal maintenance or replacement of HRC fuses for its expected life span;

- The option of specifying up to five-way non-extensible RMUs of varying configurations;
- The ability to introduce SCADA and ultimately full distribution automation functionality; and
- Cable termination enclosures compliant with NRS 012 providing horizontally positioned MV bushings at standardised heights above the cable support clamps and MV bushings ('Type C' or 'Type A') with pre-defined profiles suitable for separable connectors (screened and unscreened).

Management of existing oil-filled switchgear

As described above, the known risk profile associated with oil-filled switchgear is in most instances steadily increasing. Users have a duty, in terms of safety legislation (most notably the Occupational Health and Safety Act No. 85 of 1993) to their employees and the public to provide acceptably safe working conditions and to take reasonable action to mitigate against possible dangers. Since the danger in this case is severe injury and/or death, the level of assessment and corrective action is required to be comprehensive. In order to meet their obligations in terms of the OHS Act, it is recommended that users adopt the principles of HSE 483/27, in conjunction with the additional requirements detailed in this paper, as the basis for their strategy or policy for the management of their installed base of oil-filled switchgear.

The recommendations contained in this paper are based extensively on the content of the Health and Safety Executive document HSE 483/27. Users therefore need to obtain a copy of this document to read in conjunction with this article. The document is 20 pages in length and is therefore too lengthy to include in this paper.

However, 'PDF' copy may be downloaded from http://hse.gov.uk/fod/infodocs/483_27.pdf. For the purposes of this part of the paper, all references to 'switchgear' imply 'oil-filled switchgear' including oil circuit-breakers, oil-isolators, oil-switches and oil-switch-fuse combinations. See Appendix 1 of HSE 483/27 for definitions for these devices as well as their respective operating duties.

The recommended process to be followed is detailed below.

Note: In the following sections, the prescriptive words "shall" and "will" are used, so that the wording can be used as is in the event that users wish to use the clauses as a basis for their own policy/strategy documents.

Identification

- An inventory of all oil-filled switchgear shall be compiled and maintained.
- For each piece of equipment, all information (quantity, type, location, etc) as detailed in paragraph 24 of HSE 483/27 shall be recorded.
- For each piece of equipment, the actual system fault levels shall be compared to the equipment rating. If the actual fault level exceeds the equipment rating, immediate remedial action is indicated. This may be achieved by various means (see "Overstressed Switchgear" below).
- It shall be ascertained whether all modifications as recommended by the manufacturer have been implemented.
- All switchgear identified as either overstressed or DMO shall be suitably and clearly marked as such as soon as possible.

Overstressed switchgear

- In all instances where switchgear is overstressed, all live operation and automatic tripping of the switchgear shall be prevented.
- Access to the switchgear while it is alive shall be prevented.
- If possible and practical, the fault energy levels shall be reduced, for instance, by changing the system configuration.
- As soon as is practically possible, scheduling and budgetary constraints permitting, the switchgear shall be replaced with SF6 or vacuum switchgear, which has been tested and proven to withstand the effects of an internal arc fault in the switchgear or any of its compartments.

Note: Wherever it occurs in this paper, reference to SF6 or vacuum switchgear includes air-insulated switchgear (AIS) utilising vacuum as a medium of interruption or other metal-enclosed (either traditional withdrawable metal-clad or fixed-pattern) switchgear complying with SANS 62271-200.

DMO switchgear

- Operation and maintenance shall be restricted to trained personnel.
- All live operation of the switchgear shall be prevented.
- The switchgear shall be maintained in accordance with the manufacturer's instructions.
- If possible, remotely-operated power closing mechanisms shall be fitted to all DMO switchgear as a matter of urgency.
- When operating a DMO circuit-breaker, the method of operation given in paragraphs 33 and 34 of HSE 483/27 shall be followed.
- A phased replacement program, as detailed above in the clauses on "Overstressed Switchgear", shall be implemented for all DMO switchgear.

Other oil-filled switchgear

- In the case of oil-filled switchgear not covered by the preceding clauses, careful consideration should be given to the implementation of a phased replacement program.
- Decisions taken with respect to the replacement of oil-filled switchgear installed after 1970 that is neither overstressed nor DMO, shall weigh the cost implications against factors such as condition of the switchgear, its service life and the likelihood of failure.
- In all cases, the replacement of overstressed and/or DMO switchgear shall receive priority.
- In the interim, all oil-filled switchgear shall be properly maintained in accordance with the manufacturer's instructions.
- Operators shall confirm that the switching contacts are covered with insulating oil in good condition e.g. by means of an oil-level gauge and checking for oil leaks around the equipment. If any doubt exists, the switchgear shall not be operated alive.

Maintenance

- In order to maintain the reliability of oil-filled switchgear at a maximum, it is essential to maintain the switchgear properly and in accordance with the manufacturer's instructions.
- If any overstressed and/or DMO equipment has not been maintained within the past three years, such maintenance shall be carried out immediately.
- The work shall include the items detailed in paragraph 37 of HSE 483/27.
- All oil-filled circuit-breakers shall be maintained as soon as possible after closure onto a fault or automatic operation to disconnect a fault from the system. The maintenance shall be carried out in accordance with paragraph 38 of HSE 483/27.
- All maintenance shall be performed by trained and experienced personnel.

Replacement of oil-filled switchgear

- All oil-filled switchgear shall be replaced in terms of a phased program to be implemented after an analysis and database creation of all oil-filled switchgear in service.
- Priority shall be given to the replacement of overstressed and/or DMO switchgear in accordance with the requirements listed above.

HRC fuses (where applicable)

The following has been extracted from clause 8.103 (Operation) of SANS 62271-105 [13]:

- The three fuses fitted in a given combination shall all be of the same type and current rating, otherwise the breaking performance of the combination could be adversely affected;

- It is vital, for the correct operation of the combination, that the fuses are inserted with the strikers in the correct orientation; and
- All three fuses shall be discarded and replaced if the fuse(s) in one or two poles of a combination has operated.

The requirement for correctly replacing all three fuses of the same make and current rating at the same time is essential in order to reduce the probability of a fuse-related fault occurring. It is also critical that all fuses used are fully type tested in accordance with the SANS 60282 [14] specifications and where possible, only the make and type recommended by the switchgear manufacturer should be used.

Inferior quality or non type tested fuses such as those described above shall be replaced. The live switching of a switch-fuse combination having such fuses installed shall be prevented until the fuses have been replaced.

In addition, the switch-fuse combination shall not be energised from an adjacent switch-disconnector (i.e. sharing a common oil tank or common busbar).

Conclusion to appendix

While the above requirements may seem onerous, and involve the spending of capital which may be difficult to source where users are facing increasing expenditure with decreasing budgets, it should be borne in mind that the alternative (i.e. operating switchgear under de-energised conditions) may prove more costly to the business and economy, notwithstanding the risk that human lives may be exposed to if no action is taken. The OHS Act places a large burden on users of hazardous or potentially hazardous equipment and a reasonable person would agree that un-maintained, over-stressed and/or DMO oil-filled switchgear is potentially hazardous. Since the provisions of this act expressly forbid the sole use of PPE to mitigate a risk, it is recommended that the guidelines given in this paper are implemented by users.

Conclusions

Eskom and other major utilities in South Africa have responded to the changing risk profile associated with oil-filled switchgear in the light of developments in both knowledge and alternative technologies. They have and continue to engineer solutions for switchgear found in the distribution network that offers a significant reduction in both the total cost of ownership as well as the associated known risks. Air and/or gas-insulated switchgear utilising vacuum and/or SF6 interrupting technologies provide the users with equipment that meets the required specifications and levels of performance in a world where there is an ever increasing focus on human safety (in respect to both employees and the general public), service delivery and cost reduction.

These solutions offer improved reliability and require fewer and shorter scheduled power interruptions required for maintenance interventions. However, the existing installed base of aging oil-insulated switchgear will not disappear overnight and therefore suitable plant and safety management programmes – as described in guidelines given in this paper – are to be put in place by utilities in order to manage and reduce the associated risks.

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Cell phone vending - the Tshwane case study - the first year

by Dr. Walter Smuts, Expertron Group, and Dirk Pieterse, Tshwane Metropolitan Municipality

This paper shares experiences in rolling out a cell phone based vending system for prepaid electricity. Some of the technologies that can be used to put together a cell phone-based vending system are presented. Operational issues and lessons learnt during the first year of managing both vendors and clients when using the system, are discussed.

This includes sales statistics, system throughput, network reliability, user acceptance and the social aspects of involving people from the community in the business opportunities provided by selling electricity.

Providing adequate cash payment points for prepaid electricity can be quite challenging: enough payment points must be provided to prevent long queues from forming; payment points must be close to homes; and payment points must be open beyond just the standard business hours. The demands for adequate payment points come not only from residents, but also from government, with guidelines in terms of the minimum number of residents per payment point and the maximum distance from a house to a payment point.

These were the challenges that triggered the development of a cell phone-based vending system for prepaid electricity. Although this concept has been used for selling prepaid airtime before, there are fundamental differences between selling airtime and electricity, the most important (but not the only) being the fact that while airtime can be sold off-line, electricity sales for many types of meters must be done on-line.

This paper describes the cell phone vending system and how it operates, followed by a discussion of how the system was rolled out and used in the Tshwane Metropolitan Municipality during the past year.

The vending system

System design objectives

The design objectives for cell phone vending include the following:

- Involve the people from the community in the business opportunities created by electricity sales. The entry barrier for small entrepreneurs must therefore be low.
- Have no practical limit on the number of sales points that can be provided. Equipment for payment points must therefore be affordable – ideally it should be free.
- Have no practical limit on where electricity is sold. The payment points must be truly mobile.
- Minimise the risk for the municipality. The payment points must belong to the vendors from the community and vendors must pay up-front for all electricity they sell.

System description and operation

A cell phone vending system was built to meet the design objectives. It uses standard GSM mobile telephones as affordable point-of-sales (POS) devices to sell and distribute prepaid electricity tokens (also called vouchers).

System components

The system consists of a vending server with a GSM interface (e.g. GSM modem, SMPP link, GPRS via internet) located at the offices of the municipality. Multiple servers and modems can be used to increase reliability and throughput. The vending server interfaces with the existing STS token-generating electricity payment server of the municipality.

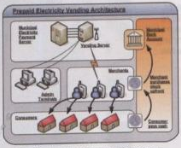

Fig. 1: Different components of the system.

A standard PC with a web browser is used as an administration terminal to administer vendor accounts. The administration terminals can be located at the municipality's existing cashier counters.

Fig. 1 shows the different components of the system.

System operation

The basic operation of the system consists of the following tasks:

- *Step 1: Register a vendor*

  The municipality identifies, signs up and trains suitable vendors. Any individual in possession of a mobile telephone and sufficient funds to purchase prepaid "electricity stock" may become a vendor.

  Vendor registration takes place at the offices of the municipality, using the administration terminal (web browser on a PC). The vendor's cell phone is registered as a POS terminal on the vending server.

- *Step 2: Vendor buys electricity stock from municipality*

  The vendor purchases "electricity stock" upfront by depositing cash at the cashier counter of the municipality. The cashier then credits the vendor's sales account, via the web interface, for the amount of "electricity stock" paid for.

  The vendor may now sell prepaid electricity up to the amount of the vendor's sales account, and earn commission for the sales.

- *Step 3: Customer buys electricity from the vendor*

  The customer approaches the vendor to purchase electricity, and specifies the amount to be purchased (which includes any transaction fees), and serial number of the electricity meter at his home.

The vendor compiles a GSM message on his mobile phone containing a PIN (to protect his sales account), the electricity meter serial number of the customer, and the amount to be purchased.

The message is sent via the GSM service to the vending server.

If the vendor's sales account has sufficient funds, the amount specified in the message is deducted from the vendor's sales account, and a response containing the 20-digit credit token is sent back to the mobile phone of the vendor. The token is obtained directly from the existing back-office vending server of the municipality.

The vendor's sales account is then credited with the commission for the transaction.

The vendor writes the numerical PIN in a receipt book and hands a copy, written on a business card, to the customer.

The customer pays the vendor cash, and enters the token into his meter at home.

If the customer has a cell phone, the token can also be sent directly to the customer's phone by SMS.

Technologies used

The system was designed to use the following technologies:

Terminals: Standard cell phones are used as point of sales devices. It was important to ensure that restrictions on the device did not limit the ubiquity of the solution. The total solution was implemented on the server side, without the need to roll out applications to the cell phones of vendors.

Communication: Three GSM communication channels have been implemented.

- *SMS:* Using SMS messages guarantees that the solution will work on all cell phones. The system is also widely accepted and needs little explanation to vendors. The cost of sending SMS messages is, however, relatively high and the interface not very friendly.
- *USSD:* The availability of USSD is a function of the network operator and not of the cell phone instruments. Its availability is in many cases not determined by technical issues, but by the network operator's ability to bill for the services. It is not as widely available in all countries as SMS, provides a simpler interface, but most probably with no cost benefit.
- *WAP over GPRS:* GPRS is by far the cheapest communication channel available, with the WAP interface also being the most user-friendly. Unfortunately it requires a GPRS- and WAP-enabled phone.

Tshwane implementation

The cell phone vending system was rolled out and used operationally in the Tshwane Metro for nine months up to October 2006. Fig. 2 shows a customer (left), buying electricity from a vendor who sells from her home in Nellmapius (a suburb of Pretoria).

System configuration and integration

A dual-redundant set of cell phone vending servers were delivered to Tshwane. The dual-redundant configuration makes it possible for a secondary server to take over, should the primary server stop working.

The cell phone vending solution was integrated into existing systems.

Existing electricity payment server

Tshwane's existing electricity payment sever provided a clean XML interface to add third-party products. The electricity payment server keeps data about customers (end-users of

Fig. 2.

electricity) and manages their accounts. The cell phone vending server keeps data about vendors (resellers of electricity) and manages them.

The existing electricity payment sever has the ability to do arrears collection (collect monthly payments for debt from customers). A two-pass transaction allows the customer to first verify the arrears amount that needs to be paid before committing to the transaction of purchasing electricity.

Free (government subsidised) electricity tokens are "piggy-backed" on top of other transactions, but can also be requested in a separate transaction.

GSM network

Tshwane opted to use only the GPRS interface and not the SMS and USSD interfaces that were available on the system. The main driver behind this decision was the low communication cost associated with every transaction. Access to the GSM network was therefore through a VPN link over the internet. Three GSM modems were, however, installed on each server to facilitate delivery of the tokens via SMS directly to the cell phones of those clients who wished to receive their tokens on their own cell phones.

Financial system

The integration with Tshwane's financial system was done in a manual way. Vendors go to one of the existing cashiers to deposit money. A standard municipal invoice is issued by the municipality. The cashier then logs into the administration interface of the cell phone vending server and credits the vendor's account with the same amount. The server sends an SMS to the vendor as confirmation that his account has been credited. The council approved a 5% commission for vendors. Commission is implicitly paid out to vendors: a vendor pays R100, after which the system allows him to sell for R105. Commission is only paid on the transaction amount, excluding VAT.

Roll-out strategy

Because of the difficulties (both political and social) of changing or terminating such a service, careful consideration was given to a proper and conservative roll-out strategy. The expectation was that the system could become difficult to manage if simply thrown open for everyone to become a vendor. Because this system has not been implemented before, teething problems were to be expected.

Pilot tests

Field trials during 2003 in Olievenhoudtsbosch (a small settlement on the southern boundary of the municipal area) showed that the technology worked and that community acceptance would not be a hindrance to the roll-out of the system. A single merchant was appointed to use his mobile telephone to sell electricity next to one of the unmanned vending machines. Very soon, the queue of buyers moved from the machine to where the merchant was selling. Discussions with buyers indicated that they preferred buying from a person they knew, to buying from a machine.

Prerequisites

In order to limit the number of vendors during the first months of operation, strict prerequisites were put in place before vendors were accepted. These included being a resident within the Tshwane Metro, not owing any outstanding amounts to the municipality and making a R5000 first payment. This was not a deposit, but was used to buy "electricity stock". This requirement was relaxed after a few months.

Vendors had to qualify for a mobile phone contract. This requirement had two purposes. The first was the fact that the potential vendor had gone through the cell phone operator's screening process. The second was to ensure that the first vendors all had identical contracts and telephones (simplifying support). After the first successful months, this requirement was relaxed and vendors now use their existing contracts and phones to sell electricity (only GPRS-enabled phones are used).

Slow growth

The rate of accepting new vendors was intentionally kept low. This allowed time to observe and put the necessary supporting infrastructure such as a help-desk in place. This strategy proved sound.

Results

Job creation

In spite of the fact that vendor numbers have been controlled, by the end of July 2006 about 120 new jobs had been created in the community. In reality these were not simply jobs but small independent businesses. Some of the entrepreneurs even employed others to help them sell, thus increasing the number of people benefiting from the system.

Service delivery

There was not a notable increase in the total number of transactions per month after the cell phone vending system was launched. Figures point to a shift in buying patterns from the unmanned vending machines to the cell phone vendors. Fig. 3 shows the monthly turnover of the transactions that were done through cell phone vendors. There was a steady increase from a low-level start in July 2005. December 2005 saw a steep increase, due to higher spending patterns during the Christmas period as well as the fact that cashier payment points were closed during public holidays.

The cashier payment points were open from 07h45 to 15h15 on weekdays and on the last Saturday morning of the month. The cell phone buying patterns show that there is a need for payment points to be open during weekends as well (between 1000 and 1500 transactions are recorded on Sundays), and that the peak purchasing times are between 09h00 and 10h00 and again between 15h00 and 17h00. These patterns match those seen for the unmanned vending machines.

Figs. 4 and 5 show the number of cell phone transactions per day as well as how these transactions are distributed, on average, during the day. Both these graphs have been taken from data for March 2006.

Customer satisfaction

Although no formal feedback was gathered from customers, the number of transactions being done through cell phone vendors point to a certain level of satisfaction. Although it is not thought that cell phone vending will replace unmanned vending machines, the fact that more than 30% of the transactions that used to go through those machines are now done through cell phone vendors points to a niche in the market for a cell phone based solution.

Vendor satisfaction

There seems to be a wide range of vendors using the system. Some try it out as a "hobby" while others have resigned from permanent jobs to run a business selling electricity. The top 10 vendors for March 2006 all had a turnover of more than R73 000 for the month, with the top vendor selling just short of R120 000 for the month.

A single vendor, with about R5 000 savings and a cell phone, can run a business with a turnover of just less than R1,5-million a year and a profit of about R75 000. To be able to do this, the R5 000 must be cycled through the system every day – which is indeed what some vendors manage to do.

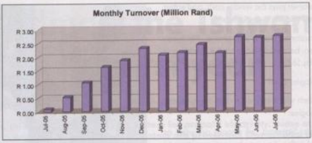

Fig. 3.

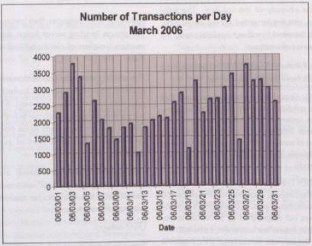

Fig. 4.

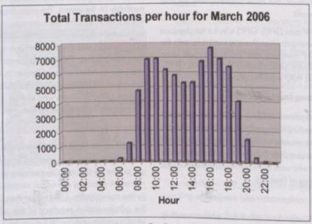

Fig. 5.

Statistics

Table 1 summarises some interesting statistics for the first year of operation.

Problems experienced

The first few months were not without problems. The following points are noteworthy:

- *Database speed*

  Transaction rates were about 10 times more than originally expected and some database optimisation had to be done to ensure that the required transaction rate could be handled.

- *VAT issues*

  Tshwane paid commission on the VAT-exclusive transaction value. Since only the VAT-inclusive values are visible to vendors, this created some confusion in terms of the commission values.

- *Double redemption of municipal invoices*

  Some vendors paid money into the

municipal account and then tried to increase the funds in their cell phone vending account by offering the invoice more than once (typically at different municipal offices). This was put an end to by a procedure of formally canceling invoices when redeemed.

Problems not experienced

Some problems were anticipated, but never experienced:

- *Imposters*

  There were fears of unscrupulous persons pretending to be legitimate vendors and taking customer's money in a fraudulent way. None of this behaviour has been reported by customers. It seems that there is a strong social structure within a community and that business is done within trust relationships.

- *GSM coverage*

  There was a single incident of bad GPRS coverage. This was reported to the GSM operator and fixed within days.

- *Transaction speed*

  It was uncertain whether all the latencies through the GSM communication channel, networks and access to databases would still result in acceptable time to complete a transaction. This was completely unfounded. Apart from the optimisation required in the database, transactions seem to flow fast enough.

- *Vendor errors*

  Incorrect recording of tokens does happen but only infrequently. The system includes a mechanism to request a reprint of a previous token. This problem has turned out to be a non-issue.

- *Vendors charging an extra transaction fee*

  There were fears that vendors would abuse the system by charging customers more than the standard price. In the beginning, while the first few vendors effectively had a monopoly in their respective areas, there were a few incidents of vendors charging an extra R2 transaction fee. This stopped spontaneously when more vendors were signed up and competition leveled the playing field.

Future development

Future extension of the system may include the following items.

- A mechanism for vendors with credit cards to top up their sales accounts remotely by doing the transaction through their cell phones.
- A payment interface to allow residents with credit cards to buy electricity for themselves. Development of this has been completed and awaits council approval.
- A mechanism for vendors to report meter problems, brought to their attention by residents, through a cell phone transaction on the system.

Parameter	Value
Total number of active consumers	110 000
Total value of sales since launch (1 July 2005 to 31 July 2006)	R24 649 891
Total number of vendors on 31 July 2006	120
Total sales for July 2006	R 2 762 894
Total number of Transactions for July 2006	82 834
Turnover for top vendor during July 2006	R 135 229
Average transaction size for July 2006	R 30

Table 1.

- A facility for payment for other services such as rates, taxes and speed fines.
- Higher commission for the vendors is being motivated to the Tshwane council - more families now rely on the income provided by selling electricity.

Outsourced operating model

Tshwane decided to operate the cell phone vending system by appointing and directly managing vendors. Some municipalities prefer an outsourced model in which the day-to-day operation of such a system is handled by a third party. Because of the low overheads in running a cell phone vending business, it forms an ideal model for involving local entrepreneurs as "super vendors", thereby extending the job- and business- creation potential to include not only the vending, but also the business of operating the vending system - which makes sense because its success depends partially on knowledge of, and acceptance by the local community.

Conclusion

After running a cell phone-based vending solution for more than 12 months, the conclusion is that although it is not necessarily a replacement for other payment points, it definitely solves a niche problem in a very eloquent way.

The technology is mature and the residents ready to embrace this new way of buying electricity. Δ

EDI restructuring process update and the way forward

Presented by W J de Beer on behalf of Phindile Nzimande, EDI Holdings

The purpose of this paper is to provide a high level update on the electricity distribution industry (EDI) restructuring process to date and the envisaged EDI reform journey ahead from an EDI Holdings perspective.

EDI Holdings was established by the government to direct and oversee the restructuring of the EDI and started to operate in June 2003.

EDI Holdings reports to the department of minerals and energy (DME), the ministry charged with the responsibility for the EDI restructuring programme.

EDI restructuring objectives

The EDI is highly fragmented leading to lost economies of scale; financial disparities between distributors; disparities in tariffs and uneven capacity to extend electricity services to poor households.

Since inception of the EDI restructuring process the government has been consistent in the objectives of the restructuring and there has never been any doubt in terms of the expectations of the government in this regard.

The energy white paper of 1998 in no uncertain terms articulated amongst others, the seven restructuring objectives as indicated in the table below.

Furthermore the EDI restructuring blue print, of which the thrust was approved by cabinet during 2001, was to serve as the guiding document for the EDI restructuring, it reconfirmed the objectives articulated in the energy white paper and also provided a level of clarity in terms of the expectation on how the regional electricity distributors (REDs) will contribute to the achieving of the key objectives.

A central feature of the blueprint is the requirement that the EDI be consolidated into 6 financially viable REDs, in order to achieve the objectives of restructuring.

The energy white paper of 1998 and the EDI restructuring blue print therefore remain important documents to serve as reference points and to assist in measuring the restructuring progress as well as the degree to which the EDI restructuring objectives are met.

EDI restructuring journey to date

The EDI restructuring journey to date has not been an easy process and numerous factors have played a key role in the slow restructuring progress experienced so far.

South Africa is one of the very few countries in the world that has initiated the restructuring of the electricity distribution industry in an environment where participation is voluntary.

Given the considerable debate which started way back in the early 1990s and which resulted in the 1997 ERIC report which supported the concept of REDs, it could be argued that the restructuring journey has been in progress for more than a decade.

The fact that President Mbeke, in the state of the nation address in 2004, indicated that the first RED would be established during 2005 provides an indication of the importance of the restructuring process from a government perspective.

It is widely acknowledged that the EDI plays a vital role in the economy of this country and is perhaps one of the most important vehicles to be used in the improvement of service delivery as well as providing basic electricity to the many people in the country who still do not enjoy the benefits to be derived from electricity.

The first RED, namely RED 1,anchored around the City of Cape Town, was established on the first of July 2005.

On 14 September 2005 cabinet considered the progress towards the establishment of REDs as well as some of the concerns raised by stakeholders.

These concerns inter alia included the financial impact on the municipalities and Eskom, the cost of salary harmonisation, etc.

Cabinet then resolved to proceed with the establishment of six metro REDs and requested that a feasibility study be conducted, through modelling, to evaluate amongst others: the feasibility of establishing a national RED; clusters; and neighbouring municipalities joining the metro RED.

EDI Holdings was charged with the responsibility of conducting the feasibility study. A process was followed which allowed for transparency and maximum stakeholder participation.

The results of the feasibility study were submitted during April 2006 to the minister of minerals and energy.

Not withstanding all the challenges, including ambivalent stakeholder support, significant progress has been made to date with reference to the RED creation process. The following achievements, inter alia, were realised:

- Metro RED-creation governance structures established and operating sponsors committees, technical steering committeesand work groups.
- Metro RED day one roadmaps and work plans developed
- Various municipalities engaged in ringfencing in preparation for the RED creation: 6 Metros have generally made good progress; 11 municipalities are at various levels of progress
- Eskom restructured its distribution business from 7 regions to 6 regions in line with the EDI blueprint six wall to wall boundary recommendation
- Significant contributions were made in terms of assistance towards the resolving of the outstanding legislative requirements
- Transitional labour relations structure (TLRS) established and functioning very effectively
- Extensive industry modelling completed
- Industry modelling report submitted to the department of minerals and energy
- Significant industry restructuring and best practices experience and knowledge developed

- Enterprise wide programme management capability established

Experience and lessons to date

The experience gained through the establishment of the first RED serves as a very important reference point on the way forward. Without the transfer of the legacy electricity businesses to the relevant RED it is hardly possible to create viable operating entities.

Furthermore, misaligned interests and ambivalent support from some key stakeholders is not assisting the restructuring process.

The following points provide some indication of the obstacles experienced to date in the establishment of RED 1 and the work done to date in establishing the metro REDs.

These matters need urgent attention to ensure progress in the establishment of the REDs. These points are:

- Voluntary mode of reform
- Absence of an enabling legislative framework
- Incompleteness and misalignment of existing legislative regime,which includes the facts that asset transfer from the City of Cape Town to RED 1 is delayed due to lack of prescribed asset transfer framework in terms of the MFMA; asset transfer from Eskom to RED 1 is delayed due to suspensive conditions imposed by Eskom; the EDI restructuring bill is an imperative to set clear policy guidelines for EDI restructuring implementation and the municipal entity governance regime is cumbersome and constraining.
- Separating out of customers, networks and systems to create a metro RED is extremely complex and does not contribute towards accelerated RED creation or leveraging existing investments in the industry
- To create a metro RED significant investments are required upfront which will not contribute to improved business performance but merely to meet the boundary reconfiguration requirements
- The negotiated nature of restructuring makes it impossible to deliver on the anticipated objectives and outcomes within the stipulated timeframes
- The current performance of the EDI is deteriorating

In addition to the above challenges there are a number of outstanding policy and legislative matters which call for urgent attention as they directly contribute to the delay in the RED creation process:

Unresolved policy matters

- End-state pronouncement
- Local government surcharge principles
- Compensation for asset contribution
- Shareholding
- Tax issues
- Ownership and governance of the REDs
- Asset transfer framework

Lack of enabling legilation

- EDI Restructuring Bill
- Exemptions from compliance to onerous legislative provisions contained in, for example, MFMA and systems act

RED creation journey ahead

EDI Holdings has every confidence in government and there is no doubt that the Government is committed to the EDI reform process and will pursue a model which will serve the best interest of South Africa and its people.

Based on extensive research, lessons learnt and experience to date, EDI Holdings is convinced that the 6 wall to wall RED model, as approved by cabinet in May 2001, remains the most appropriate option for the EDI in South Africa.

Furthermore based on legal analysis, lessons learnt and experience to date:

- REDs should be established as public entities
- The EDI restructuring should take place on a mandatory basis, supported by the necessary enabling legislation

With reference to the RED creation journey ahead, the current negotiation and EDI reform governance arrangements will be leveraged in aligning the current RED creation activities with the final cabinet decision.

The work done and lessons learnt through the establishment of RED 1 and in preparation of the metro REDs will, amongst others, be used to inform the RED creation journey ahead.

South Africa is in the fortunate position to exploit opportunities to learn from the international experience in electricity distribution reform.

The importance of all stakeholders is acknowledged and therefore the stakeholder engagement will be intensified to enhance engagement on the way forward and to address potential uncertainties.

It is envisaged that the multi stakeholder forum (MSF) will be revived to facilitate inter alia the resolving of the outstanding policy matters

Conclusion

The EDI restructuring journey to date has had many obstacles and taking this into account, good progress in terms of the EDI restructuring has been made to date. The government has allowed for a very transparent and participative process in terms of the restructuring and EDI Holdings has utilised these opportunities in the national interest.

A decision by government on the EDI model and way forward is imminent. Based on the level of readiness, understanding of the EDI and stakeholder relationship, EDI Holdings is committed to deliver the EDI model in line with the final cabinet decision in this regard.

EDI Holdings wish to thank all the stakeholders who have made a positive contribution towards the restructuring process.

Without the support of all the stakeholders, this journey has the potential of being a very difficult one.

In conclusion, EDI Holdings appeals to all the stakeholders and in particular the industry leadership, to commit to the restructuring process and to proactively participate in this journey in the best interests of South Africa and its people. Δ

Security and adequacy of supply in South Africa

by Vally Padayachee, City Power, and Tore Horvei, Sad-Elec

Security and adequacy of power supply in South Africa will become a real concern if certain proactive steps are not taken or implemented timeously. If a GDP growth of 6% p.a. is to be realized as part of government's ASGISA initiative then generation capacity must be increased by approximately 2485 MW each year from now until 2025.

Collaborative efforts by all industry players (generators, distributors and customers) are required to address these challenges – strategic partnerships are required. This paper seeks to address some of the challenges facing South Africa and proposes some possible solutions. Though based on available data the assessment of the situation is a point of view by the authors.

Introduction

South Africa's electricity industry is fast eroding its current capacity - the system reserve margin is already very low. There is uncertainty about the future demand growth. The current electricity demand growth is 3,0 to 3,5% per annum. Higher GDP growth rates increase pressure on the electricity supply system. Reduced demand elasticity is expected in the medium to longer term. Decisions about new generating plant must be fast-tracked to meet incremental growth in demand, to restore system reserve margin to an acceptable level. Governance and decision making frameworks are being put to the test. Readily available generation options are limited in the near to medium term. OCGT solutions are being introduced to address peaking capacity shortages. Coal-fired plant will continue to dominate the base load market. Natural gas (for CCGT and CHP applications) and nuclear have roles to play. DSM, demand side participation and distributed generation need to feature more strongly.

Security and adequacy of supply

Secure, reliable and adequate electricity supply is critical to economic and social growth and development in South Africa.

What are the issues relating to security of supply?

- Sustained availability of existing generating plant and power systems
- Improved composition of plant mix
- Broadening technology and fuel choice
- Restoring a reasonable system reserve margin
- Timely decisions on new generation expansion
- Clarification of framework for private sector participation

What are the issues relating to adequacy of supply?

- Engagement with customers to ascertain expectations and trade-offs
- Clarification of the EDI reform process to unblock supply capacity constraints, particularly in metro areas
- Harmonised and streamlined regulatory frameworks

GDP growth vs. electricity demand

According to information from Statistics SA, South Africa's electricity demand growth (up to now) seems to have kept pace with the country's GDP. However, will the historic relationship between GDP growth and electricity demand continue?

A weakening of the 'one-to-one' relationship is expected to lead to lesser interdependency:

- In the short to medium term, an increasing share of GDP growth will come from large but less energy intensive infrastructure projects
- Significant growth in less energy intensive sectors of the economy such as financial services and ICT as well as tourism forecasts a structural change in the composition of the South African GDP
- The success of demand side management (DSM) initiatives, primarily targeting growth in peak demand
- Changes in energy market dynamics
  - LPG replacing some electricity usage in domestic/commercial sectors
  - Natural gas increasing its share of commercial and industrial markets

GDP growth p.a.	Electricity growth p.a.	Total capacity required 2005-2025	Annual capacity required 2005-2025
3,0%	1,4%	11 772 MW	620 MW
4,0%	2,3%	20 824 MW	1097 MW
5,0%	3,2%	32 257 MW	1698 MW
6,0%	4,4%	47 252 MW	2485 MW

Table 1.

The following information from Eskom reflects the huge challenges facing the country if the government's 6% GDP growth per annum (government's ASGISA initiative) is to be successfully achieved.

In essence we need to increase our generating capacity by approximately 2485 MW every year till the year 2025. See Table 1.

Demand growth scenarios

Eskom's official registered system peak demand reached 34 800 MW on 29 June 2006. Its annual peak demand growth from 2006-2010 is estimated at 3,2% based on short to medium term economic growth forecasts.

From 2010, two (Eskom) demand growth scenarios are considered:

- Low case: 4% GDP growth p.a. with electricity demand growth of 2,3% p.a.
- High case: 6,0% GDP growth p.a. (based on ASGISA, government's accelerated and shared growth initiative) with electricity demand growth of 4,4 %

Eskom Generation expansion and technology choice up to 2015

Up to 2015 the following generation options are being pursued:

- De-mothballing of Simunye plant (Camden, Grootvlei and Komati): Total of 3600 MW of capacity to be added
- Arnot coal-fired expansion: 300 MW
- Liquid fuel fired open cycle gas turbines (OCGT): Eskom (1050 MW) + DME tender (1 050 MW)
- Bramhoek pumped storage plant: 1330 MW

- New base-load PF coal plant: Matimba B (2100 to 4200 MW) + other coal options
- Potential natural gas fired combined cycle gas turbines (CCGT): Kudu (800 MW) + Coega (1600 MW) + Eskom/Sasol co-gen plant

We pose the question - is this enough?

Eskom Generation expansion and technology choice - after 2015

Post-2015, many technology options exist:

- Base load options:
  - PF coal-fired stations
  - CFB coal-fired stations
  - Conventional nuclear plant
  - Pebble-bed nuclear reactor (PBMR)
- Mid-merit options:
  - Natural gas fired CCGT plant
- Peaking plant options:
  - Liquid fuel fired OCGT plant
  - Pumped storage plant
- Commercial scale renewable energy options (e.g. solar-thermal)
- Import from SADC region

Security of supply – what is required?

- Sustained high plant availability
- Timely decisions on generation expansion:
  - Elaboration of government policy framework is key
- Engagement of customers and new approaches:
  - DSM and dynamic market participation (DMP) – not only by Eskom but also EDI in general e.g. munics, metros, REDs
  - Co-generation options (Combined heat and power – CHP)
  - Distributed generation solutions
- Appropriate regulatory frameworks:
  - New Electricity Regulation Act provides framework, but detailed regulations are lacking
- Sufficient financial resources:
  - Eskom has a strong balance sheet, does it need to be sustained?
  - Future tariff increases matter (to Eskom, EDI and IPPs)

Conclusion

We propose some solutions to the challenges posed by security and adequacy of supply:

- Improved management of existing assets – by Eskom and the EDI in general
- More active customer engagement on DSM and DMP – by Eskom and EDI
- Increased use of distributed generation solutions – by Eskom and EDI
- Progress policy and regulatory framework on IPPs and private sector participation in new generation developments:
  - Reconsider management of future generation tenders due to government capacity and skills constraints
  - Finalise and implement regulatory framework for co-generation applications
  - Engage the private sector on proposals for increased use of non-Eskom plant and expansion of such. Δ

Transformation, mergers & aquisitions - a management perspective

by Dr. Willie de Beer, EDI Holdings

Over a period of 18 months research was done on a selected panel identified from international and local companies which went through transformation, or a merger or an acquisition. With reference to the panel from the international companies the focus was specifically on electricity distribution utilities.

The aim of the research was to understand from a practical point of view what worked and yielded the desired results, and what did not work.

In addition to this research, a range of hypotheses was evaluated from both a theoretical and a practical perspective. In general, when dealing with transformation or a merger and acquisition there is significant focus, and rightly so, on the core business related matters such as synergies, technical dimensions, financial matters, systems etc. However what this research focused on was to understand some of the other key success factors that are not effectively managed most of the time, and the research therefore focused among others on:

- Key success drivers from a management perspective
- Key drivers behind failures
- The role and selection of leadership
- The role of executive sponsors

This presentation only deals with a limited section of the total research. The aim is to provide a very high level perspective on the key transformation, merger and acquisition success drivers from a management perspective.

Transformation, mergers and acquisitions

Transformation, merger and acquisition (M&A) initiatives are a world wide phenomenon. These initiatives are viewed by various people as best-practice world trends and essential for a business to survive in an ever changing and very competitive environment. There are however also those people who express the view that this is not necessarily the most preferable business practice. Irrespective of the differing views, transformations, mergers and acquisitions are taking place at an increasing rate, and cannot be ignored. It is however clear that the challenges facing the business world brings among many other challenges also the challenge to continuously look for ways to ensure business sustainability and growth.

The electricity distribution industry (EDI), while historically regarded as a "different type of business", has also experienced a world wide increase in these initiatives. South Africa is no exception and the current EDI transformation raised the question: what are the success drivers for an effective business transformation or merger and acquisition?

While investors are looking for financial returns, the shareholders are looking for shareholder value creation and the employees are looking for careers and job opportunities. There is clearly a significant interdependency should the ultimate goal be a successful business transformation that addresses the current inefficiencies of the EDI. The challenge is to create wholeness.

Many people, including some leaders simply do not have the confidence to embrace the change and make the necessary leap into the future despite all the compelling reasons for change. Kotter (1996:185) states: "For a lot of reasons, many people are still embracing the twentieth-century career and growth model. Sometimes complacency is the problem.

They have been successful, so why change? Sometimes they have no clear vision, and so they don't know how they could change. But often fear is a key issue. They see jobs seeming to disappear all round them. They hear horror stories about people who have been downsized or re-engineered out of work. They worry about health insurance and the cost of college for their children. So they don't think about growth".

The drivers behind successful transformations, mergers and acquisitions

Based on the research results and the feedback from the respondents in the target population the following points were highlighted as key drivers for successful transformation initiatives or mergers and acquisitions:

- Effective leadership
    - Transformation leadership
    - Leadership sustainability
    - Executive sponsor
- Realistic vision
- Setting realistic goals and managing the transformation tightly
- Communication
- Motivation
- Persistence
- Business/culture acumen

The visibility of effective leadership and the ability to communicate the transformation vision and goals clearly stands out as mission-critical in ensuring transformation success.

Should this learning point therefore be applied to the EDI transformation in South Africa, then it suggests that it is critical that the leadership at government level as well as industry level urgently come to an agreement on the way forward. It is essential to recognise that people play a critical role in the ultimate success of the transformation initiative. Credible and visible leadership is critical to the success of any process. Without proactive leadership it is most unlikely that any process will yield the desired outcomes.

It is through effective leadership that people are inspired and that stakeholders are willing to buy into a process even if the potential outcome is not that certain. "Leaders inspire others, provide emotional support, and try to get employees to rally around a common goal" (Kreitner, 2001:551). Without visible leadership, tangible commitment and consistency, any process runs the risk of failure.

The ultimate success of the transformation process is dependent on the ability of the leadership and the key industry stakeholders to respond to the transformation challenge and to direct the limited resources available. The difference between successful and less successful transformation initiatives could also be linked to the level of staff engagement. Failure looms in the absence of staff commitment and their lack of belief in the transformation journey. Staff must appreciate their role and understand their accountability for delivery. Without effective staff contributions and delivery of outputs on time and at least within the agreed to quality parameters, the potential of a successful transformation could fade away. It is therefore essential that clear and realistic goals are set and the deliverables are managed tightly. Effective delivery requires focus and a sound interpretation of the mandate, understanding the expectations of the decision makers, having clarity on the delivery time lines and agreement on the key assumptions. Uncertainty in terms of the deliverables provides excellent opportunities for people to influence the direction and the speed of a process negatively. This is even more so should the perceived outcome conflict with their personal agendas or perceived benefits. It is also important that the deliverables and time lines set should match the execution capacity and capability available. Bossidy (2002:30) states: "No matter how well you execute, the risk of failure increases markedly when the ideas you develop don't fit with your existing capabilities, or force you to acquire those capabilities at too high a cost".

The research results suggest that the creation of vision should preferably not be a bottom-up process; it is a leadership accountability and must be driven from the highest level. Furthermore that vision is about promoting a leap of faith into the future. The vision must create a sense of urgency in all people associated with the business or the process. "Without a sense of urgency, people won't give the extra effort that is often essential" (Kotter, 1996:5).

Ultimately the vision must be owned by the stakeholders and they must be able to relate to the vision and they must be comfortable with it. Frequent changes in direction or changes in terms of deliverables is cited as a contributor to the lack of buy-in from the stakeholders or resulting in the stakeholders losing confidence and interest in the initiative. The frequency of changes and the level to which stakeholders' interest is lost, could also be regarded as "failure potential" indicators and therefore deserves close monitoring and management attention. The energy of the staff must be directed towards constructive contributions, and impatience about the lack of progress must be managed. Failure to direct the energy could escalate the transformation failure rate.

The research results suggest that it is important to identify and agree up front to specific areas to be measured and the associated quality criteria. Agreed-to measurement areas and the relevant metrics facilitate effective reporting and progress tracking and also contribute to providing focus for the people. Aligning the outputs of the people with the agreed-to measurements and measurement areas provides purpose for the people i.e. they can see how their contributions impact on the transformation.

Communication must be proactive, consistent, and reliable while the origin must be trustworthy. Poor communication before the start of an initiative is regarded as just as bad as poor communication during and after the initiative. To generate trust, motivate and instill confidence in the process, the communication channels must be open and work effectively upwards and downwards. From a communications perspective there is a need for simple messages which are easy to understand and which could be released on a regular and proactive basis. Some messages might have to be repeated since repetition is sometimes needed to get a message accepted. Potential inconsistencies and conflicting messages must be addressed head on, to protect the credibility of the communication and the transformation process in general. Unco-ordinated communication or communication not received on time or not ahead of key events, is an important contributor to the less-than-desired results of transformation initiatives and mergers and acquisitions.

The response suggested that, to motivate people, whether employees or otherwise, requires the treatment of people with integrity, dignity and respect - and a sense of appreciation and value must be created. People in general expect good treatment and they expect that firm measures will be taken against deviations from agreed-to performance standards. You clearly cannot buy motivation and commitment or force motivation and commitment on to people through threats or any other means. Just as respect is earned; generating commitment and motivating people calls for leadership and management commitment, listening skills, being trustworthy and the treatment of people with dignity and respect. Nelson (2005:14) indicates the need to manage your own opinions and viewpoints and states: "Do not let your own opinions and points of view interfere with hearing what someone else is saying". The surest way of killing contributions or stifle motivation is to adopt the so-called "I know it all" style.

Leadership commitment to reaching the goals, underpinned by a strong work ethic, is cited by some of the respondents as characteristics of persistent leaders. While there is an observation that leaders who demonstrate being persistent should accommodate a level of flexibility, the response also indicates that these leaders are decisive in the implementation of the transformation strategy. The secret could be in their ability to learn and leverage best practices and effectively work with people.

As wide and as diverse as the scope of business/governance/cultural dynamics might sound, the research indicates that these components are vital elements in the success of transformation. These factors all contribute to the ultimate business environment. The business environment in turn could impact on the business performance and the attitude of the people. "The environment shapes people's attitudes and feelings. The right environment will encourage, motivate, and liberate people to perform" (Hammer, 1996:105). The business culture is influenced by its leadership, how it is governed, the business values and how it is managed. The leadership to a large extent shapes the business culture. The research results indicate that leaders who plays a positive role in helping people to sustain their ability to contribute in a positive manner and who are regarded as a key source of inspiration behind the successful transformation, are people who encourage innovation and who respect cultural and social differences. These leaders are people who can leverage diversity and have the ability to align activities with the vision.

Understanding the business and financial imperatives were rated by the respondents as contributors that could lead to transformation failure if not effectively managed. The absence of appropriate quantification of the expected financial returns and the lack of effective management controls to realise the benefits, could contribute to transformation failures. It is therefore to be expected that in successful transformation initiatives systems, financial targets, goals and controls are well defined and effectively managed. It is essential that the potential liabilities are well defined and that appropriate risk-mitigating strategies are developed well in advance to avoid the potential of a negative impact on the transformation success rate. In the absence of appropriate ringfencing of the business to be transformed or merged, the risk of not understanding the systems, financial and contractual obligations could increase significantly.

The lack of appropriate business information, benchmarks, and reliable financial statistics could complicate the transformation process significantly and could further increase the failure potential. Without proper financial analyses and a well defined transitional plan the initiative cannot be successful. Elements highlighted with reference to business governance and cultures, as deciding factors in determining the potential level of transformation success or failure are:

- *Business*: due diligence; systems integration; labour relations; flexibility, resource allocation and task alignment.
- *Governance*: legislative compliance; contractual obligations; transformation implementation strategy; speed of decision making; speed at which change is implemented.
- *Cultural dynamics*: cultural differences; change management; staff empowerment.

Leadership dimension

Based on the research results it can be concluded that there are specific leadership dimension that enhance the degree of transformation, mergers and acquisition success.

These dimensions can be summarised as:

- Motivation and directing: leadership; creating vision; and networking.
- Situational analyses: exploring opportunities; evaluating; how to communicate; and when to communicate.
- Decision making: taking decisions in time and specifically during times of uncertainty; and follow through
- Deliver on the mandate: how to retain focus; and recognition and reward
- Power: responsible use of authority; competitiveness and will to succeed; and retain and build credibility

Leadership attributes to ensure sustainability

It is not surprising that the research suggests that leaders play a significant role in ensuring sustainability and providing an anchor to stakeholders during times of transformation, mergers and acquisitions.

The research also indicated a marked correlation between the leadership attributes to ensure sustainability and the drivers behind successful transformation, mergers and acquisitions. If staff, for example, is not empowered, trusted and actively participates in the transformation process, the risk of failure could become a reality.

Empowered staff will demonstrate their commitment to the process through their behaviour and contributions. Powerless staff will however also demonstrate their lack of commitment through their behaviour and lack of quality contributions. "The most important things managers can do to develop and maintain motivated, energised employees have no cost, but rather are a function of how employees are treated on a daily basis" (Nelson, 2005:63). The research results suggest that in leading a successful transformation initiative, the leadership must fully appreciate the differences in cultures of the businesses to be transformed, merged or acquired.

A sound appreciation is required of the way in which the different businesses are operated, their value systems, what could be leveraged, what could be terminated and by when.

The five key leadership dimensions that sustained motivation and supported the ability of individuals to contribute to the transformation success are as follows: communication; vision; motivation; persistence; and business/culture acumen.

Selecting a leader

The early appointment of the leadership provides focus, direction and confidence in the process. Early appointment of the leadership also brings about a level of stability and removes position-jogging and politicking to a certain degree. Since the importance of effective leadership was clearly highlighted as a very essential dimension for success, it was necessary to explore through the research what could be regarded as the essential dimensions in selecting a leader.

It is important to note that these dimensions were derived from the real experience of the respondents and were tested and verified against supporting theory. Essential qualities of the leadership, particularly during transformation, are the ability to direct and to motivate people. The criteria for the selection of an effective leader to lead a transformation, merger and acquisition initiative should, based on the research, include the following:

- *Relationship strengths*: ability to foster sound relationships; ability to comfortably interact at all levels; effective communicator; and strong ability to motivate and lead.
- *Business acumen*: sound overall business understanding; sound appreciation for governance and compliance requirements; and sound ability to set business direction.
- *Strategic thinker*: ability to create vision and purpose; and ability to proactively identify and explore opportunities
- *Industry knowledge and expertise*: knowledge of the industry; and appreciation for the industry challenges and opportunities.

Executive sponsor

The research results suggested that the importance of an executive sponsor and the role that such a person can play for success should not be underestimated. In the normal business operation an executive sponsor would be a person at an executive level nominated to act as the sponsor for a specific output or project. By way of example, the executive sponsor will represent the board of directors and will manage the relationship at the most senior level, facilitate the decision-making, nourish and direct the project team, and take ownership for providing access to the resources required to ensure the effective execution of the project. The concept of an executive sponsor becomes essential specifically when the transformation initiative cuts across an industry where all participants do not fall under the same governance regime.

The typical roles that an executive sponsor will play include:

- Paving the way for the effective execution of the project
- Generate support for the project among the ultimate decision-makers
- Provide strategic guidance and direction to the transformation leadership
- Ensure transformation alignment with the shareholders' vision
- Advocacy of the project through active and visible support

The EDI transformation is a classic example of a national government initiative driven in the national interest but dealing with a multitude of stakeholders and at least four government departments. Clearly it is essential that effective integration must take place among the relevant four ministers and that agreement is reached at this level on the national imperatives to be derived from the EDI transformation. For a project of national dimension, the classic business approach cannot be followed in terms of the appointment of the executive sponsor, due to the level at which the incumbent must interface.

It could be argued that since the government charged the minister of minerals and energy with the accountability to lead the EDI transformation that the minister, by default, became the executive sponsor for the EDI transformation.

Early stage transformation, M&A failure indicators

Successful transformation requires high levels of commitment and focus on the effective management of all the diverse challenges. Even when things are going well, there is no room for complacency. "Complacency is the number one threat because it breedsoverconfidence and inattentiveness" (Kreitner, 2001: 636).

It is not surprising that the research suggest a significant correlation between the drivers for successful transformations and the fundamental reasons for transformation failures.

The following dimensions were identified through the research as potential early stage transformation, merger and acquisition failure indicators:

- *Poor communication:* lack of communication; lack of change management; and lack of feedback.
- *Lack of vision:* lack of detail in the vision; and vague or changing end-state goals.
- *Lack of stakeholder buy-in:* lack of stakeholder commitment; lack of political support; lack of organised labour support; lack of staff support; cultural differences not respected; and disconnect between transformation success and employee interests.
- *Financial:* lack of financial analyses and controls; lack of defined financial targets; lack of reliable business and financial information; and ineffective due diligence.
- *Other:* ineffective business governance structure; lack of legislative support; lack of legal compliance; contractual obligations which could not be honoured; incompatible/ lack of system integration; ineffective programme management; speed of transformation too slow; and lack of transformation flexibility.

Early stage success indicators

The research results equally identified very distinctive dimensions which could be used to determine at an early stage the potential transformation, merger and acquisition success rate.

These dimensions include:

- Visible executive sponsorship
- Strong leadership
- Effective communication
- Motivation
- Managing of cultural/social differences
- Encourage innovation
- Vision, buy-in and alignment of activities to the vision
- Due diligence
- Effective programme management
- Effective and proactive measurement

Conclusion

In general the transformation, merger and acquisition failure rate is regarded as high. However in unpacking the failures most of them suggest, not a failure in the concept, but rather in the way it was researched, planned, managed and implemented. The different approaches taken around the globe clearly indicate that there are many ways to facilitate a relatively fast and successful transformation process that will realise the desired benefits.

To obtain this, however, requires effective leadership, thorough planning, well designed and communicated implementation plans, commitment, an effective change management programme, effective programme management and resources.

Whether it is a transformation initiative, a merger or an acquisition, they all have in common a defined goal and a defined time line within which it must be executed.

Furthermore transformation initiatives, mergers and acquisitions consist of multiple activities and projects cutting across the business and involve people of various and different disciplines and skills.

The challenge however remains to create something that will present long-term sustainability and complement both the pure business requirements as well as the socio-political requirements.

"Without change, organisations would not progress, they would not have an opportunity to serve new customers and take advantage of new markets, and employees would not be able to move forward in their careers.

Change allows all this and much more" (Nelson, 2005:24). At times there is a need to take a position or stand and with conviction and integrity to step forward and provide direction. This is, in many cases, required when there is uncertainty and perceived lack of direction.

This paper and the supporting presentation represent only a fraction of the research results. However in the time available this is about as comprehensive as one can be be with the subject. Δ

Electricity restructuring – the Cape Town experience

by Louise Muller, City of Cape Town

RED 1 was formally established on 1 July 2005 by the City of Cape Town with the city holding 5 shares. This is in terms of the articles of association, which allow for the founding municipality to hold 5 shares after completing the necessary service delivery agreement with RED 1.

Further shares will be obtained once the compensation policy has been determined nationally and the transfer of electricity staff and assets has occurred.

The decision to operate RED 1 as a municipal entity was only put in writing by the Department of Minerals and Energy in a letter directed to Eskom on 23 May 2005. Due to this late notification on the type of entity to be established, RED 1 complies with the requirements of the Service Delivery Agreement by sub-contracting the services of Eskom Western Region and the City of Cape Town Electricity Undertaking to provide electricity distribution services on its behalf.

The Agreement signed with the City of Cape Town allows for the transitional arrangements for electricity distribution as well as for the transfer of the City's electricity undertaking to RED 1 within a period of 12 – 18 months.

The agreement signed with Eskom also allows for the transitional arrangements for electricity distribution within the City of Cape Town jurisdictional boundaries, but has a number of suspensive conditions that must be fulfilled before the transfer of electricity distribution from Eskom to RED 1 can take place.

These suspensive conditions are predominantly related to various sections in local government legislation which Eskom wants repealed or relaxed – due to the current void of pertinent legislation for the establishment of the electricity distributors.

The Department of Minerals and Energy is attempting to negotiate with the national treasury on the relaxation and exemption of various sections in the Municipal Finance Management Act as well as with the Department of Provincial and Local Government on changing various sections in the Local Government Municipal Systems Act.

RED 1 originally appointed two members of staff, these being the chief executive officer (CEO) and the chief operating fficer (COO). The COO subsequently resigned. RED 1 appointed a chief financial officer (CFO) from March 2006. The CEO has appointed a personal assistant. RED 1 will be funded, during the interim phase, by the City in the form of a management fee for the oversight of the electricity distribution taking place within the full jurisdictional area of the City of Cape Town. A maximum amount of R10-million was budgeted for this management fee by the electricity undertaking in the City.

The City went through the necessary process to appoint directors to the board for RED 1. There are currently 6 directors appointed by the City. All board members are non-executive. The CEO and the CFO are ex officio board members at all board meetings.

The City has nominated an official to be the parent municipality's non-participatory observer at board meetings.

Dynamics of the current electricity restructuring process

While the above gives a short précis of where the city is with its electricity restructuring, it must be stated that the process has been challenging.

Below are some of the dynamics that have, and contiue to be experienced by the author and other role-players during this process.

Section 78 process – predetermined outcome vs. actual outcome

Section 78 of the Municipal Systems Act (MSA) clearly outlines the process for reviewing current service delivery mechanisms and determining alternate mechanisms for service delivery. This is a long process that must be taken step by step and is, to a large extent, written with the expectation that an external consultant would assist with the process.

Once the decision has been made to appoint an external service provider, another process lasting at least 90 days is outlined in the Municipal Finance Management Act (MFMA). (See section 84 of the MFMA.) This is a long process to follow, simply to come to the result of what has already been published in every newspaper in the country!

Is the process then to follow the legislative parameters rigidly and hope desperately that the outcome is, in fact, what the "required outcome" must be? Or is the process dictated by what the outcome must be?

While we may be asking these questions about the creation of REDs, should we not be asking this all the time? Surely you do not embark on the costly section 78 process without some thought in mind of what you want to do in the future?

The vision for the RED's vs MED's

(RED = Regional Electricity Distributor; MED = Metropolitan Electricity Distributor)

The restructuring of the electricity industry is a complex process. Adding to this, national government has not concretised the final vision for the restructuring of the electricity distribution industry and on Wednesday 14 September 2005, cabinet was briefed on a plan to accelerate the implementation of the electricity restructuring.

The outcome of the meeting was recorded as, it being agreed that 6 metropolitan REDs will be set up as soon as possible after the local government elections. The legislative requirements for enabling the smooth transition have, to date, not been finalised.

When working on the founding documents of RED 1, city officials spent very many hours analyzing local government legislation and debating options to find workable solutions for the greater area that would bee serviced by RED 1. It is clear that the municipality with effective control, or holder of the greatest municipal shareholding, has some significant say in the running of a municipal entity.

However, legislation also allows for various other municipalities that may have been in a RED (or any private company that is a municipal entity) to have some input into the general processes to be followed. Section 93C of the Municipal Systems Act refers to the kind of relationship that needs to be formed between the municipalities that share the service provider. (Also refer to section 86F of the MSA.)

Parent municipalities that have shared control of a municipal entity (ME) **must** enter into a mutual agreement determining and regulating:

- Their mutual relationships in relation to the ME;
- The exercise of any shareholder, contractual or other rights and powers they may have in respect of the ME;
- The exercise of their powers and functions ito the MSA and the MFMA with respect to the ME;
- Measures to ensure that annual performance objectives and indicators for the municipal entity are established by agreement with the ME and included in the ME's multi-year business plan (per S87(5)(d) - MFMA);
- The monitoring and annual review, as part of the ME's annual budget process (per S87 – MFMA), of the performance of the ME against the establishe performance objectives and indicators;
- The payment of any monies by the municipalities to the ME or by the ME to the municipalities;
- Procedures for the resolution of disputes between those municipalities;
- Procedures governing conditions for and consequences of withdrawal from the ME by a municipality;
- Procedures for terminating the appointment and utilisation of the ME as a mechanism for the performance of the municipal function, and
- The disestablishment of the ME, the division, transfer or liquidation of its assets and the determination of the responsibility for its liabilities.

The City Of Cape Town had written into the service delivery agreement (SDA) that a municipal forum would be established where the parent municipality (the City of Cape Town in the case of RED 1) would deal with issues raised by all the municipalities and take a single stance to RED 1.

All these processes fall by the wayside with the establishment of MEDs – and metropolitan municipalities no longer have to take up this daunting role. However, it creates a problem for the national RED, if that is still the process being followed. (The "follow-up" cabinet decision was still outstanding on the final vision for the electricity restructuring process at the time of writing this paper.)

Does this revised vision for the restructuring of the electricity industry trigger a new section 78 process? This question must be raised in conjunction with the first area this paper investigates.

However, to what extent could the original section 78 process deal with the greater area to be covered by the original proposals for the regional electricity distributors?

Assuming all the figures for all the areas within the proposed region were readily available, to what extent would it be considered that the section 78 process pre-empted the outcomes of the individual section 78 processes in each and every municipality within the regional area?

It is also questionable to what extent that information would or would not be required for a council to make an informed decision. Perhaps it would only be required for those municipalities that have effective control through majority shareholding.

However, if not all the information was available for the section 78 report, would that make a decision taken based on the report an incompetent decision? Once again, the "required outcome"/publicized "resulting structures" must be borne in mind ...

The negotiating teams in the municipality – those who are to move vs. those who stay

The process followed by the City of Cape Town was a co-operative process, facilitated by EDI Holdings, with the role-players including city representatives covering the finance, information technology, human resources and electricity operational areas as well as Eskom officials.

It soon became clear that while all Cape Town officials had a common objective, i.e. the creation of RED 1, the visions and views on the process and outcome held by City of Cape Town officials alone were widely divergent.

While it may have been ideal to portray a single united "city view", during negotiations, it was clear that those who were staying with the city could not always support the proposals of those who were moving into the newly created entity.

This process continues to play out as more consideration is given to the assets and staff transfers that need to take place. This is to be expected, considering that the officials are looking at the same objective from differing views, and are protecting different interests.

However, the process will be hampered where a lack of trust starts creeping in to the process and negotiations. There should be no hidden agendas - negotiations need to take place in an open and transparent way.

All parties need to have a common understanding of the vision for the final "product" – easier said than done when the national vision has been changed mid-stream! If the parent-child relationship outlined in legislation is recognised and accepted, it immediately becomes clear that the municipality and the municipal entity are dependent on each other for their existence and thus no one particular party should be unfairly advantaged or disadvantaged.

If there is a lack of acceptance of the parent role that the municipality must take with respect to the municipal entity, there will always be conflict. The electricity restructuring process does not remove the responsibility for the provision of electricity reticulation away from the municipality (refer specifically to section 81 of the MSA)!

The negotiating teams – municipal vs. public entity

The differing viewpoints expounded on above become far more evident when negotiations take place between municipal officials and officials from Eskom. The Public Finance Management Act has been in place for a good while longer than the Municipal Finance Management Act. There has also been more emphasis on ensuring the necessary regulations for public entities are in place. The municipal entity legislation has only recently been substantially overhauled.

Even still, there are some significant differences in the legislation for public and municipal entities. The local government sphere is also significantly more legislated and this legislative framework guides all local government officials.

Obviously, Eskom officials have not necessarily been exposed to all the different local government legislation, just as municipal officials have not necessarily been exposed to the Public Finance Management Act.

The impact becomes clearer once the related agreements have to be negotiated in order to fully establish the electricity distributor or the municipal service provider and the service authority role needs to be outlined in the Service Delivery Agreement.

The Division of Revenue Acts for the last two years have covered the need for municipalities to enter into service delivery agreements with the service providers in their municipal areas.

This has been a difficult process as Eskom has been so entrenched in various areas that the local government responsibility and right to provide electricity reticulation services (as per Schedule 4B of the Constitution) has been overlooked. Thus, municipalities have not been taking up the service authority roles and responsibilities.

Municipal undertaking vs. private company (social vs profit motive)

The creation of the municipal entity is essentially the establishment of a private company. This private company receives direction from the board of directors. The municipality will source the directors for the board from various different organizations in order to cover all disciplines/fields of expertise.

Many of these directors may well come from the private sector where the profit motive drives the daily operations. This is significantly different from the social motive, which permeates every action performed by a municipality.

The local government sphere is the service delivery arm closest to the ground implementing the national government basic services and related free basic services policies. At the same time, the municipality must deal with the social issues within its boundaries in order to ensure economic growth, increased rates base, constant revenue streams, etc.

Thus, the provision of basic services to all can often override the balance between social and economic development. This balance can be restored through the arms length distance of the municipal entity from the municipality.

The shareholder will set certain key targets/ key performance indicators for the municipal entity, while the board of the entity will drive out economic efficiencies.

Uneasiness regarding the municipalities "parent role" as outlined in the MSA will prevail initially as the board understands the difference between the private company scenario where the board has the final say and the municipal entity private company scenario where the board has the final say, when the parent municipality has given its permission!

Service authority vs. shareholder

The parent municipality of any municipal entity is legislated to play two differing roles: that of the service authority; and that of the shareholder.

At this time I am investigating the role of the Shareholder Compact (which is a legislated document for public entities) to clearly identify and differentiate between these two responsibilities.

It may be argued that the Municipal Systems Act covers the Shareholders Compact in the Service Delivery Agreement. However, section 81 of the Municipal Systems Act makes it clear that the Service Delivery Agreement (SDA) is a longer-term document.

The treasury regulations stipulate that the Shareholder Compact for a public entity will cover a period of three years, updated annually on a rolling basis.

While not a legal opinion, I have clarified the role of the Shareholder Compact in my mind, at this stage, as the following:

"The Shareholders' Compact it is an agreement (among the shareholders) to allow the Service Authority to take up the monitoring and management role, as outlined in local government legislation, in order to hold the board of the service provider accountable against specific performance targets, without any claim of conflict of interest or self-dealing against that shareholder. – Louise Muller's Definition of the Shareholders Agreement"

To me, the agreement/compact therefore serves to promote and encourage good governance practices by clarifying the respective roles and responsibilities of the board of directors and the management of the municipal entity and those of the shareholder, both in the role of shareholder and as the service authority.

This issue of the service authority runs deeper than simply a shareholder's compact. It seems clear, from the Municipal Systems Act read in conjunction with the Municipal Finance Management Act, that the policy and tariff issues related to a municipal service remain with the service authority and are not transferred to the service provider.

This simple fact is often overlooked when dealing with the ring-fencing process that precedes the establishment of an external service provider. Once the decision has been taken to use an external service provider, these "service authority roles and responsibilities" must be unbundled from the internally ring-fenced provider of the service.

Consequently, if the ring-fencing process is being initiated with the aim of establishing an external service provider, then the service provider roles should not be ring-fenced.

Conclusion

The electricity restructuring process is being driven nationally with national timeframes being imposed on the local government sphere. Yet, the national vision is still a bit vague and very few of the formal legislative processes are in place to provide the required guidance.

Thus, while the perspectives provided in this paper are limited, in the future, as further clarity is obtained, they may be considered an extremely narrow sample of some of the dynamics experienced.

Irrespective of this fact, it is clear that there are a number of lessons that can be learnt from the process, no matter how far the progress. Through all the processes and procedures, however, we must not lose sight of the foundation of the electricity restructuring: to bring better service delivery to a wider range of clients in the most effective, economical and efficient manner possible. Δ

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The majority of things in life are done the easy way; water will run through the easiest course, electricity will follow the path of least resistance and predators will select the weakest target for their next kill.

Humans are no different and when faced with options for the future, most would make the decision based on which choice requires the least input or change. Only a rare few will tackle the more challenging option but armed with foresight and a genuine commitment to the spirit of the BEE Charter, this is exactly what Cual Engineering (Pty) Ltd, an historically family owned business, did.

Mike and Andrew Walsh were adamant that becoming a BEE company not be an exercise which further empowered someone who had already had access to the empowerment process. Their patience finally paid off and Mrs Mpume Gwala joined Cual in July 2005. Mpume came from a construction background where she put her skills as a Qualified Quantity Surveyor to good use.

Mpume has purchased 26% of the shares in Cual Engineering - which was no easy feat as raising the capital to buy into the successful family business meant putting everything she owns on the line. Mpume carries the title of Director by virtue of her shareholding but joined Cual as part of the Sales Team – a position which has seen her grow from strength to strength, and now sees her as an integral, motivated part of the Cual Team.

"Some days are lonely, some days are frustrating because of the loads of work but that is what makes it so exciting. In this field of work, you can never say that you know it all – you actually learn everyday because you are dealing with so many diverse people, companies and situations" says Mpume.

Operating from Durban, Johannesburg and Cape Town, Cu Al Engineering supplies to customers throughout Southern and Central Africa, as well as around the world.

The Company manufactures as well as represents many well-known manufacturers, both locally and abroad, and offers a wide range of products ex-stock including overhead power line material, Preform Line Products, cable jointing, heat shrink products and ABC fittings. Customised products to individual specification can also be supplied.

Cu Al Engineering (Pty) Ltd has a national distribution network with its own fleet of transport linking to all ports and a stock holding in excess of R 16m which enables very prompt delivery and service. Exports are handled by an experienced in-house export department.

Recognising the success of a service driven organisation lies in the skill, experience, dedication and attitude of its people. The company is strongly committed to the training and development of staff and to the South African policy of Black Empowerment. In keeping with this policy it offers technical assistance to black owned businesses.

The challenge for Cual Engineering, going forward, is to ensure that the company continues to deliver the level of service on which its longstanding reputation is built and that it will continue as one of the leading suppliers of Overhead Power Line Material to the power industry.

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Developmental local government electricity distribution

by Russell Baloyi, SALGA

Developmental local government is about recognising the developmental nature of local government functions, and the need to use revenue generating services and electricity surplus in particular to finance other services. Energy and the current electricity distribution industry restructuring process should be seen in the context of service delivery and development.

At the global level, the United Nations has adopted eight millennium development goals (MDGs) to be achieved by 2015 in response to the world's main development challenges. Energy scarcity and poor supply condemns many women and children to collecting firewood, fetching water, and performing a number of daily tasks manually in addition to delaying development.

Electricity can bring needed lighting to homes and schools creating a better environment for children to learn. Energy, therefore, is a vital input in reaching the second millennium development goal: achieve universal primary education.

In fact without access to reliable and affordable energy, people are denied basic health and education services and opportunities for improving their lives.

Energy is again paramount to achieving all the eight millennium development goals, from education to health care to gender equality and ensuring environmental sustainability.

People working in the industry should not see their work in isolation to the overall impact of the industry in the development of our communities and improving the quality of life.

People working in the industry are directly contributing towards better life for all and should not see the use of electricity surplus in other services as a problem, but rather as a contribution of the industry in addressing the developmental needs of our communities.

Countries in Africa have different systems of local government, and in some countries local government is not recognised as a distinct sphere of governance. The lack of legislative framework, limited powers and functions and lack of accountability are among some of the key issues facing local government in Africa.

However, in the South African context it is important to start by pointing out that all spheres of government are distinct spheres of governance and play a pivotal role in economic growth and development in all areas of South Africa.

The overall government approach to service delivery shows that planning and authority on the delivery of basic services is devolving to the implementation level, which is developmental local government.

This approach is clear from the restructuring of the transport sector, water, housing, etc., that have seen local government assuming more responsibilities.

The Constitution and the Municipal Systems Act also provide for certain powers and functions to be assigned to municipalities that have the capacity to undertake such functions.

The powers and functions assigned to municipalities are inter alia influenced by the municipality's economic viability and position. Municipalities that are economically weaker do not have a sound source of revenue such as taxes and user charges.

Municipalities vary in their capacity to discharge their constitutional mandate, and it must be noted that the level of governance, resources, capacity and systems differ from municipality to municipality. It should therefore be acknowledged that the impact of the REDs on municipalities will differ between categories of municipalities.

The SALGA members assembly which took place in Ethekwini in June recommended that we uphold, respect and recognise the following key principles that were agreed upon to guide the electricity industry restructuring process:

- Restructuring must be conducted in accordance with the Constitution, taking into account that the responsibility for electricity reticulation is a municipal function;
- The financial state of municipalities currently performing the electricity function must not be adversely affected;
- Any RED end-state model must meet the restructuring objectives set out in the EDI Blueprint that was approved by cabinet earlier.
- The Restructuring of the electricity distribution industry should be done in such a way that it does not impact on municipalities' ability to play their developmental role, and the achievement of the millennium development goals and the national target of universal access to electricity by 2012 is dependent on municipalities being able to play their developmental role at the local level where people need service delivery. Δ

Six issues affecting restructuring of electricity distribution

by Prof. Trevor Gaunt, Department of Electrical Engineering, University of Cape Town

20 years ago, in the mid-1980s, power station construction in South Africa was proceeding fast, as Eskom built its way out of the power shortages earlier in the decade. Then consumption growth slowed, and suddenly there was too much capacity. There were two important responses: electrification and restructuring.

By 1990 electrification was envisaged as Electricity for All. It became the National Electrification Programme and between them the two programmes doubled the number of households in South Africa with access to electricity. The cost was high, about R10-billion, but the contribution to meeting socio-economic and social objectives was substantial.

The electrification proposals were accompanied by proposals for restructuring. Radical restructuring was justified as necessary to achieve the ambitious numerical objectives, fund the electrification programmes, reduce prices, and generate many other benefits. There were many proposals and progress reports to AMEU meetings and elsewhere, but compared with electrification, negligible achievements have been made with restructuring, although the costs have been significant. The proposals have created uncertainty in the industry and contributed to the neglect of maintenance, loss of experienced staff and widespread failures of supply. Perhaps the cost of restructuring has exceeded the cost of electrification?

This paper explores six broad issues likely to affect how these two processes, electrification and restructuring, may develop in the future.

Fundamentals

Most of the participants in the electricity supply industry agree on the fundamentals, although this may not be apparent to those outside the debates! The common objective is development, which can be characterised as having three components

- Economic development pursues efficiency, growth and financial return.
- Social development is concerned with equity, justice and poverty alleviation.
- Socio-economic development seeks long-term sustainable changes of lifestyle.

The differences between the participants in development arise from their differences in values, interests and resources. The contestation of resources leads to apparent conflict between the participants and is essentially political, though not necessarily a party-political activity. The outcomes of the political processes are structures and systems of control and influence. These structures and systems may distort the attainment of the original objectives, through the effect often referred to as unintended consequences.

Unintended consequences usually arise from a lack of awareness or an inadequate understanding of the situation, in this case the electricity distribution industry and all it encompasses. Misinformation and mistakes in decision-making are seldom reversible, demonstrating the importance of information that is clear, accurate, appropriate and easy to understand. Given the size and complexity of the electricity distribution industry, the information does not always meet this specification!

Also, given the irreversibility of most decisions and events, it is necessary to recognise that, whatever the history, progress can only be made by recognising the reality of the present situation and moving forward from that position. The following issues are discussed in that context. To limit the complexity, the discussion is constrained to electricity distribution, although many aspects apply similarly to transmission and generation.

Open "SECRET"

Based on my own experience and analysis of the distribution industry in South Africa, I have identified what I consider to be six significant issues: skills, entitlement, capacity, reliability, environment and tariffs. They cannot be completely separated from each other, and an alternative analysis might identify alternative clusters of characteristics, but they provide a useful format.

1. Capacity

The limits of the capacity of the national electricity network have been very evident recently. Frequent interruptions, compared with international benchmarks, affect urban and rural areas. Significant failures have occurred in all the main cities, with the disruptions in the Western Cape being arguably the most evident and costly for the economy. The limits of generating capacity were identified in forecasts prepared in the 1990s, which appear to have been reasonably accurate. With all generation committed, the delivery networks are also operating close to their limits, particularly when the inevitable faults occur and N-1 contingency planning is shown to be inadequate. Even without faults, the domestic customer load research programme has identified that the supply voltages for many customers are well outside the quality of supply limits adopted as regulatory standards. Networks operating close to capacity and with large voltage drops incur high technical losses.

While the capacity of the power system is a problem for some, there are others who do not even have access. Electrification reached nearly 70% of households in 1999, but since then the net rate of connections has only just kept pace with the construction of new households, with the result that access had increased to only 72% by 2005. (Note: This figure does not appear to have been published and is derived from various reports of connections and household numbers.) At this rate, and with the present level of allocations from the National Electrification Fund, it is unlikely that universal access will be achieved by 2012, in accordance with government policy.

The implementation of load shedding, whether voluntary or imposed, and the unsupplied demand of those who have no access distort the reporting of the real demand for electricity.

The problems of the capacity of the networks indicate the limited ability of the institutions responsible for electricity distribution to improve the situation.

The issue is: The distribution industry does not have enough electricity to meet customer requirements, the networks do not reach all the customers, the existing networks are under severe strain, and the institutions themselves cannot respond adequately to the needs.

2. Entitlement

The problems of capacity lead naturally to consideration of who is entitled to have electricity. Since electricity supports economic, socio-economic and social development, it appears that industry, commerce, other institutions and households all have a right to consume. Constitutionally, municipalities have the rights and responsibilities to supply electricity to customers in their areas. Similarly, the national utility, Eskom, was established to ensure the adequate and economical supply of electricity to those requiring it, in support of national development. Clearly entitlement in the electricity sector is complex.

One change from the period of giddy power station building of the 80s has been in the concern for the environment. The need for and desirability of large fossil-fuel burning power stations is now more than a financial decision based on costs and potential tariff revenue.

Serious consideration must be given to emissions and alternative uses for the fuels, various technologies for generating electricity or alternatives for reducing the energy used. Within this context, it might become acceptable in future to restrict the consumption of electricity by the large customers who presently appear to be limited only by their willingness to pay.

At the other end of the scale, the social entitlement of domestic customers to electricity drives the electrification programme and the provision of free electricity. Even then, many poor households cannot afford sufficient electricity for heating energy, and alternatives like paraffin and LPG are always under consideration. However, the value of subsidising the delivery of more than one form of energy raises questions about which form is the most appropriate and why it should be supported to the exclusion of other interests.

The issue is: While both customers and suppliers are entitled to participate in electricity delivery, the conditions under which supply should be provided are unclear.

3. Environment

Concern about the environment and climate change is strongly affecting the electricity industry in Europe and North America. Natural gas is preferred to oil and coal because of the lower carbon dioxide emissions per unit of electrical energy generated, but the maximum improvement is less than 25%. Renewable energy sources have no carbon emissions, as in wind generation, or have a short life-cycle such that the emissions equal the carbon absorption, as in generation from sugar cane bagasse.

The major problem with electricity from renewable sources is the high cost compared with conventional central generation, at least when based on normal financial analysis.

Most "renewable electricity" is financially viable only when policies are expressed in financial terms, such as carbon taxes, emissions trading and direct subsidies, or when government regulations dictate that a proportion of electricity must be generated from renewable sources.

However, since any taxes or extra costs are part of the economic system, the support of renewable electricity through policy instruments distorts the allocation of resources through the market system. Further, subsidies for renewables reduce the availability of funds to subsidise other socially desirable processes, such as electrification and poverty alleviation.

Many developed countries have established environmental policies and substantial subsidies that create financially viable opportunities for small-scale dispersed generation (DG) from renewable sources. DG and renewable energy technologies have significant implications for the planning and operation of electricity systems, including the emergence of active distribution networks.

Intrinsically viable generation possibilities, such as from bagasse or hydro power stations, require new grid codes and similar regulatory support to reduce the artificial barriers protecting monopolistic utilities. In contrast, "environmental" programmes that are not financially and economically viable weaken developing countries that are already short of resources for development, and should not be supported by special regulations.

Nuclear generation shares some of the advantages of renewable generation, such as negligible carbon or sulphur emissions. While concern is expressed at the high cost of waste management, financial analysis using even low net discount rates shows that the negative effects of long-term future costs on project viability are small. Accordingly, nuclear power is emerging as an environmentally acceptable source with low costs similar to coal power stations.

The issue is: Central generation and conventional distribution, with limited DG supported by suitable grid codes and international subsidies, may provide the most attractive electricity supply in South Africa for a long time, while some other renewable energy policies may not be justifiable locally despite the importance of environmental sustainability.

4. Tariffs

While diversity of supply capacity was an objective of the White Paper on Energy Policy (in 1998), the distribution objectives clearly pursued uniformity, leading to proposals for six equal regional electricity distributors playing on level fields, despite differences between customer density, economic activity and network development in various parts of the country. Restructuring was justified in part as necessary for tariff rationalisation and raising the funds for electrification, but the result would be to conceal cross-funding and subsidies within the distributors.

The National Electricity Regulator (NERSA) was unable to achieve any tariff rationalisation in ten years, for any class of customer, despite tariff rationalisation being one of its objectives. The large number of complex tariffs makes it difficult to monitor and assist the few utilities that are financially unstable for a variety of reasons. Conventional objectives of tariff design, including stability, cost reflectivity, and transparency of subsidies, appear to have been submerged by the emphasis on restructuring of the institutions. Although the municipal demarcation process has shown that tariff changes can be forced by merging utilities, restructuring is not a precondition for tariff rationalisation. In contrast, the agglomeration of customers by electricity service companies has allowed them and selected customers to benefit from distortions in tariffs, without adding value in the form of physical infrastructure, operations or maintenance.

Even when opportunities arose to adopt country-wide tariffs, such as a proposed single structure basic electricity support tariff, it was decided instead to allow municipalities to introduce free basic electricity (FBE) in whatever form they wished. This freedom appears to have contributed to the situation in which some customers deserving social subsidies still do not have FBE. Similarly, the acceptability of off-grid electrification was compromised by inconsistently high tariffs for small quantities of energy, in the order of R60 per month for 6 kWh.

In spite of the general lack of progress towards the objectives of tariff policy, much has been learnt about tariffs and pricing. The elasticity of demand for small customers has been measured and demand market participation has indicated the willingness of larger customers to shed load when financially compensated. This information could usefully inform tariff design in future.

Finally, the national electrification programme met its numerical objectives without funds freed

from a restructured industry, and subsequently the government recognised the desirability of funding large social investments from the central fiscus. These developments indicate that the concepts of tariffs, funding and utility structure underlying the proposals for change were apparently incorrect.

The issue is: Why has tariff rationalisation - which has significant potential for implementing economic and social policies without radical organisational change - been virtually neglected?

5. Reliability

Tariffs represent the costs of supplying electricity. However, tariffs do not represent interruptions costs, which have become more visible in South Africa recently because of the widespread and extended blackouts in metropolitan areas, and claims that the interruptions have had a substantial impact on economic activity. In rural areas also, there are concerns that the costs of interruptions are substantial. Closely related to the cost of an interruption is the value or worth of an uninterrupted supply.

The development of national grids was a response to the need for increased reliability at acceptable cost. Interconnection of power stations and loads allowed the possibility of losing any one generator to be covered by the capacity of all the rest. This led to the concept of N-1 contingency planning, by which a whole system should be able to operate adequately with any one component out of service. However, as systems grow, the probability of more than one component not being available increases.

One failure might not be noticed until the next failure initiates collapse, or multiple failures occur before the first can be repaired. Therefore, large systems require more sophisticated approaches to reliability, including the separation of risk and consequence, and the integration of planning, operations and maintenance.

Reliability is not limited to interruptions. Voltage quality, in terms of variation of voltage magnitude, voltage dips, harmonics and unbalance, affects the efficiency with which electricity can be used by the customers.

Many countries are trying to use integrated power systems, which were developed to improve reliability, as vehicles to impose energy competition. In the absence of true competition that can accommodate the many customers' different requirements, reliability is usually managed through performance regulation. However, since failure is a stochastic (probability) event, the actual performance may not be an accurate representation of the character of the system, and imposing severe post-event penalties is probably counter-productive in terms of effective system management.

The issue is: Reliability is the result of a complex relationship between planning, operations and maintenance, which are largely technical activities that should take into account the costs of both supply and interruptions, and is not easily managed by utility profit objectives and financial penalties for failures.

6. Skills

The core business of an electricity utility is the supply of electricity and the primary capability needed is technical. Practical technical skills and engineering understanding and experience are vital for planning, building, operating and maintaining the physical system that delivers electricity to customers. Shortages of those skills lead to problems: safety and costs depend on the physical integrity of the power system, protection systems determine the response to faults and the reliability of the supply, and metering is needed for revenue collection. There are clearly deficiencies in all these areas.

Technical skills and experience do not come in faceless packages. They are supplied by people with different expectations. Some want to belong to small communities while others want the scope and promotion opportunities of large organisations. Diverse utilities suit the needs of different people, as well as providing varied experience. If suitable opportunities are denied, then people move to other utilities or into other businesses. Uniform institutions, like the proposed regional electricity distributors, do not provide the diverse conditions needed to train and retain the best skills and experience.

Successful development requires that the best use is made of all the skills and experience available. The industry cannot afford to pursue racial and gender transformation so aggressively that it limits capacity. For example, consulting engineers carry out many tasks that are not sufficiently continuous to justify full time staff in small and medium municipalities. Recently however, some local and provincial government tender requirements have been so restrictive that even black-owned consultancies cannot qualify without supplementary points for disability or women. Large utilities also have problems, with widespread reports of under-investment in human capital. And in competition with new projects, the less visible areas of operations and maintenance suffer most from shortages of skills.

The universities and technical colleges contribute substantially to preparing new entrants to the industry and have the potential to provide "continuing education", but are under-resourced in funds, staff and adequately-prepared students.

The issue is: Present policies are inadequate for training and retaining the technical and engineering skills needed for viable electricity distribution, and uncertainty makes conditions worse.

Electricity distribution in the future

The above six issues are complex, but not a secret. Improving electricity distribution depends on understanding the complexity and adopting realistic policies and programmes to replace the simplistic proposals that treat only one issue at a time.

What then can we expect of electrification and restructuring?

Electrification

Environmental pressure will encourage the adoption of some renewables technologies, but they will be limited by high costs and a lack of local subsidies in favour of meeting other social and economic needs. The greatest emphasis will be on grid electrification. It will be necessary to develop entitlement and reliability policies regarding to whom, how and under what conditions electricity will be distributed.

Progress will be made towards building the network capacity for universal access, accepting that the technical innovation required and the high marginal cost of reaching deep-rural customers, such as in Limpopo and Eastern Cape, will delay completion. The need for demand management and effective and efficient poverty alleviation will probably lead to new tariffs for electrification customers. Continued financial support at adequate levels will be needed from the National Treasury to meet the national objectives of electrification and poverty alleviation. The eventual success of electrification will depend on the utilities retaining the skills needed to implement innovative systems and operate and maintain them.

Restructuring

Examination of the complex issues demonstrates the inadequacy of the simplistic concept of REDs and the radical and risky change they represent. A variety of initiatives and approaches is needed to make the best use of capacity and resources. A process of incremental change generates fewer unexpected consequences. Recognising that it is unnecessary to fix what isn't broken, competition by comparison can be introduced. The performance of utilities in all categories of economic, socio-economic and social development can be compared. Successful utilities should be encouraged and supported. Those failing in their responsibilities need to change or be taken over by others, transferring the assets at no cost along with the obligations.

This incremental approach builds on the institutional capacity and diversity of the successful municipalities and encourages responsible municipal management. It will allow time to stabilise the systems, processes and human resources that have been disrupted by successive mergers of about 800 municipal and provincial electricity authorities into fewer than 190 utilities. Urgent attention is needed to human resources or skills and aligning tariffs.

The regulator (NERSA) should be responsible for comparing the utilities, withholding licences from the ineffective ones unable to meet their obligations, and guiding tariff reform. For example, it is evident that the costs of supplying electricity may be higher in some places than in others. National tariff rationalisation will need to be supported by transparent subsidy transfers to support the more costly distribution.

Many other aspects also need attention, but removing the uncertainty and confusion inherent in the proposed REDs restructuring makes it possible to give attention to the details. NERSA could be strengthened by incorporating EDI Holdings, which has capacity but no purpose without radical restructuring. A strong regulator with clarity of vision and purpose could contribute significantly to incremental restructuring of electricity distribution in South Africa.

A new vision

Rapid electrification and new visions for energy policies and regulation, which characterised the exciting 1990s, plodded and stumbled through the first half of this decade. The electricity industry and the country cannot wait another five or fifteen years for new impetus to develop. Eskom is taking bold initiatives to remedy the deficiencies in generation and transmission. The municipalities should be equally bold in delivering the electricity to customers to support economic and social development.

There is no future in simplistic restructuring proposals. Failure to act constructively increases the problems and risks of the industry and the possibility it will fail in ways demonstrated in various other African countries. Municipalities have responsibilities and they must meet them in the context of the existing structure of the electricity industry. However, this is not a justification for business as usual. The problems are complex, and many changes are needed to improve the delivery of electricity.

This analysis tries to create a better awareness of the relationships so that the participants can use their own information and logic to develop appropriate policies, and act on them.

There should be no secret in successfully restructuring electricity distribution. It's simply part of our business. Δ

Beyond prepayment – smart meters for evolving networks

by Roland Hill, CBI electric: Low Voltage

Prepayment meters have become an essential tool for the delivery of electricity services to developing communities. Domestic consumers prefer prepaid services due to the financial control its provides them, and the simple rate of consumption feedback presented.

The products have matured, become more dependable and have been internationally standardised. Vending systems have likewise evolved into online transaction servers regulating a significant flow of funds.

However, there is growing evidence that the basic prepayment meter lacks significant attributes important to the provision of a safe, sustainable and satisfactory service to consumers. This paper seeks to shed light on improvements that are emerging and highlights the work that needs to be done to ensure that all manufacturers adopt a common set of enhancements.

Service experiences and the equity challenge

The White Paper [1] on transforming public service delivery defines the "Batho Pele" principle of putting people first, which requires:

- Redressing the imbalances of South Africa's past
- Maintaining continuity of service to all levels of society
- Focusing on the needs of the 40% of South Africans who are living below the poverty line
- A shift away from inward-looking, bureaucratic systems, processes and attitudes
- A search for new ways of working which puts the needs of the public first, is better, faster and more responsive to the citizens' needs.

The objectives of service delivery enhancement therefore include welfare, equity and efficiency.

Obviously, the rising occurrence of public protest is evidence that consumer experiences are not meeting the rising expectations. Fig. 1 presents a simple model to illustrate the service delivery gaps that exist. These are noted in more detail thereafter.

The intuitive notion that sponsored (indigent) consumers are due an inferior service as they are not paying for their services, has to be challenged. The Batho Pele principle requires that a child-headed family in an AIDS-plagued community must be given an equitable level of service.

The fact that we aren't sure how to do this in a sustainable manner or that we don't have the capital, generation capacity or capability to do this is a different matter. We cannot deny the challenge.

Planning for escalating service expectations

It needs to be appreciated that satisfactory service levels are not static. Thus what was an acceptable service five years ago, is no longer sufficient to fulfil a consumer's escalating expectations. This can be demonstrated by observation of the highly competitive computer industry as shown in Table 1. This parallel creates a subconscious precedent in a consumers mind as to what service levels could/should be. It is worth contrasting this with the service practices prevalent in the monopolistic electricity industry.

Sadly, most of the electricity industry's service levels are constrained by the capabilities of equipment installed in the 1960s and 70s.

Perhaps it is unfair to compare the fast-moving computer industry where product lifetimes are as short as three years, to the electricity industry that typically has thirty year product lifetimes. But this is exactly the point - the long product lifetimes that presently constrain the service options available to a utility, must force us to consider the service requirements of new meters to at least thirty years into the future. This requires some serious crystal ball-gazing and industry consensus-building efforts. The capability to achieve this needs to be strengthened and mentored.

Waves of service convergence ignite innovation

The prepayment industry came about through the convergence of electronic measurement technologies and low voltage switchgear technologies. It is increasingly apparent that these technologies are now converging with public communication infrastructures, thereby spawning a new generation of "smart electronic meters".

Fig. 2 illustrates some common forms of these products and lists the related IEC standardisation working group and normative specifications.

Recent standardisation efforts have acknowledged the need for coexistence and integration of data from these forms of smart meters and the above working groups have engaged a process of establishing a common information modelling (CIM) language for each form. It is expected that future meter management systems will deal transparently with information streams from each form, and that ultimately commercial pressures will force the products to merge into a single, simplified

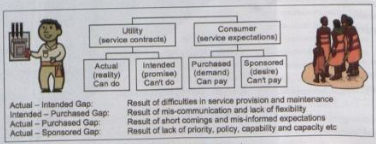

Fig. 1: Service perception gap analysis.

smart meter. The remainder of this paper portrays the kinds of smart meter services and technologies that will be deployed. These will need inspiration and standardisation to be truly effective in enabling the level of services that will be demanded by tomorrow's consumers.

Enabling consumer choice with multi-service meters

Prepayment suffered an emotional backlash when it was first imposed on township communities as it was perceived to be a poor man's solution. Many communities rebelled against this discrimination and utilities were forced to offer a choice of prepayment or conventional supply. Having been given a choice, communities overwhelmingly adopted a prepayment service due to the consumption control provided. As more forms of service emerge, utilities should be able to configure their smart meters to the changing needs (whims) of their customers, without having to visit the site and swap physical assets. The industry needs a standardised method and dataset to achieve this in a secure and auditable way. Typical service alternatives are given in Fig. 3.

It is beyond the scope of this paper to describe the intricacies of each of the above services, but it is worth noting that the key to the viability of any service control mechanism is that it should be in the customer's interest that the control mechanism operates. This ensures that the service will be accepted and adopted by the consumer. Wherever possible, supply disconnection should be avoided and supply capacity restrictions (MAL, MPL) should be used until full service restoration. A multi-service meter should be capable of working on mini-grid or off-grid supplies where the supply frequency is intentionally not stabilised to save on the capital cost of the infrastructure.

Enhancing quality of service with multi-function meters

The drive for universal access in developing countries demands that services are extended to remote rural communities. The challenge of providing a safe, sustainable, equitable service to all at an acceptable cost per connection forces the integration of multiple protection measures into a multi-function meter (ECU). In its cheapest form, a multi-function meter is the entire installation, and the utility is bound to incur significant support and maintenance costs arising from malfunctions of the consumer's installation and appliances. This seems an expensive luxury.

Naturally, there is substantial resistance to utility provision of such extensive service

Decade	Label	Ability	Defining activity
1940s	Showing	Display	Store owner chooses when and where to exhibit
1950s	Telling	Present	Sales force go out and describe extent of services
1960s	Selling	Listen	Marketing staff emphasise benefits of their services
1970s	Choice	Diversify	Customer selects what he wants from many options
1980s	Now	Deliver	Customer says when and where he wants it
1990s	"I"	Customise	Customer defines the service he wants and gets it
2000s	Value	Value Eng	Customer declares what he is prepared to pay
2010s ?	Saving	Conserve	Customer controls and directs his usage
2020s ?	Control	Manage	Customer expects service integration benefits
2030s ?	Morph	Adapt	Co-generation and adaptive infrastructures

Table 1: Characteristics of service escalation since the 1940s.

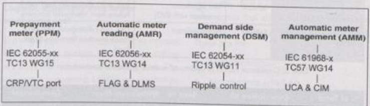

Fig. 2: Characteristics of specific smart meter implementations.

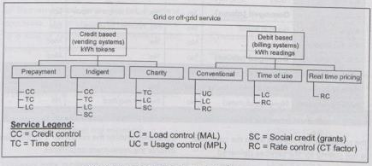

Fig. 3: Service capabilities of a typical multi-service meter.

Protective Function	Primary purpose	Conventional 80A meter	Prepayment 60A ED	Indigent 20A ECU
Main isolator	Installation safety	No (1)	No (1)	Yes
Over current	Installation protection	No (1)	No (1)	Yes
Fault current	Installation protection	No (1)	No (1)	Yes
Earth leakage	Consumer safety	No (1)	No (1)	Yes
Raised neutral	Consumer safety	Should (5)	Should (5)	Must (3) (5)
Over temperature	General safety	Should (5)	Should (5)	Must (3)
Lost neutral	Appliance protection	Should (5)	Should (5)	Must (3)
Over voltage	Appliance protection	Customer (2)	Customer (2)	Must (3)
Under voltage	Appliance protection	Customer (2)	Customer (2)	Must (3)
Lightning surge (4)	Appliance protection	Customer (2)	Customer (2)	Must (3)

(1) The national wiring code ensures that protection is installed and operational in the installation
(2) Customers must be adequately informed of their risks and mitigation options
(3) Utility must accept responsibility when rural/poor consumers are unable to protect themselves
(4) Surge protection must not be integral to the meter if it is prone to decay and/or catastrophic failure
(5) Should be provided by the utility when proven capabilities exist in the deployed equipment

Table 2: Idealised assignment of utility responsibility for additional protective functionality.

protection, maintenance and support services from a commercial, logistical and emotional standpoint. It is argued that the utilities' responsibility is limited to the provision of a safe (split) metered supply and that further protective measures are the responsibility of

Type tests	Compliance tests	Accelerated life tests	Acceptance tests
IEC 62052 & SANS 1524	"STS WG7"	IEC 62059 & Eskom ALT	IEC 62058 & SABS Mark Scheme

Fig. 4: Ensuring the quality and dependability of metering systems.

Assurance Mechanism	Usage	Application	Confidence factor
Cabinet or cover tamper switch (TS)	Common	25% using disconnect 75% audit counter	Low as it is typically not functional when supply is absent
Imbalance current detector (ICD)	**Growing**	Particularly with BS terminal arrangement	Good, detects load connections to earth with swapped live and neutral
Load switch bypass detector (BVD)	Growing	Not significant (combine with ZCD)	Low, can't distinguish load switch failure from bypassed meter
Zero current detector (ZCD)	Seldom	Not significant (combine with BVD)	Low, can't distinguish load switch failure from intentional jamming
DC current detector (DCD)	Seldom	Not significant	Low, can't distinguish deliberate diode insertion from non-linear load

Table 3: Confidence factors of additional revenue assurance mechanisms.

% of Total in the field	Description of Malfunction	Sent to Manuf	Withdrawn from service	Commercial risk
0.25%	Faulty	Yes	No, warranty repair	Low
0.25%	**Damaged (abuse)**	Yes	No, out of warranty repair	Low
0.5%	No fault found	Yes	No, returned to service	Low
1% (estimate)	Faulty	No	Yes	Med
2% (estimate)	**Damaged (abuse)**	No	Yes	Med
10% (estimate)	**Free supply mode**	**No**	**No, not detected**	**High**
20% (estimate)	**Not sealed correctly**	**No**	**No**	**High**
66% (estimate)	None (good meter)	No	No, not required	Nil

Table 4: Commercial risk assessment and significance of meter system malfunctions.

the consumer, particularly when the consumer is not paying for the services delivered.

The consequence of this limited service is that all consumers are expected to understand the severity of the hazards arising from use of the (invisible) service, to have sufficient knowledge and resources to purchase and install the necessary protective devices, and/or to procure sufficient insurance for any damage that may occur due to inadequate protection. This seems highly unlikely in the case of the child-headed home previously mentioned.

The National Energy Regulator (NERSA) is entitled to impose the provision of additional protective services as future licence conditions, when they are technically possible and viable. The provision of such functionality in a meter should therefore be provided as soon as possible, and in a manner that gives the consumer and utility the option to negotiate and structure an appropriate and fair sharing of risk/cost that could vary with time. The features should be programmable and must be able to be disabled. Table 2 indicates the range of protective services that can be incorporated and recommends when they should be activated by the utility to protect the consumer and/or the consumer's installation and/or the consumers appliances.

To better understand the need for utilities to provide additional protective functionality for rural and indigent consumers, consider the case of a typical family in Africa. Normally, this family would save for three years to be able to purchase a bicycle which is a notable measure of wealth, ridden by men and boys only. In an act of benevolence, the utility arrives, installs and supplies free electricity as part of a social development initiative. The family therefore foregoes the purchase of a bicycle in favour of a television. Research shows that up to 60% of such televisions are destroyed within a year by supply irregularities. The provision of the free service thus has a disastrous financial impact on the poor when adequate protection is not provided.

Measures to improve revenue assurance and meter survival rates

It is recognised that improved revenue protection requires more than mere technological improvements in the electricity meter, as:

- Supply diversion regularly occurs elsewhere in the supply chain
- Most mechanisms are prone to false indications that reduce confidence in them
- There is no substitute for proper, independent audits.

Table 3 lists mechanisms that can be provided and records the confidence factor they provide.

The common practice of supply disconnection upon (probable) detection of tampering should be avoided in favour of a detect, record and alert strategy. This minimises consumer frustration and aggression arising from inadvertent supply interruptions. Table 4 indicates the significance of various meter malfunctions. The amount of meter damage from vandalism and abuse is significant.

It would be worthwhile researching the actual cost of poor service to confirm if the magnitude of commercial risk from improper sealing and undetected tampering is indeed a two orders of magnitude greater than the risk of actual meter failure.

Measures to improve metering system dependability

Clearly, the survival rate of meters is highly dependent on the level of service actually experienced by the consumer, which is in turn dependent on the dependability of the metering system. Thus service and support efforts are required to soothe consumer frustration and technical efforts are required to maximise the operational dependability of the complete metering system. Table 4 lists the ongoing technical efforts, and utilities are advised to ensure that they have requirements for latest versions of these in their tender documents.

One worrying factor facing meter manufacturers is the growing incidence of counterfeit components being fraudulently introduced onto their production lines. To gain confidence, it is worth investigating the degree of rigour with which manufacturers screen their incoming materials, and the thoroughness (fault cover) of their production test equipment. This is what minimises embarrassing, confidence-destroying and costly recalls.

Measures to enhance consumer value and energy conservation

Demand-side management features will be incorporated into meters, and it is important to distinguish between utility and consumer-initiated measures. Utility initiatives must offer consumers something in return for service restrictions that help the utility manage the generation and distribution of their service. It is extremely difficult to guarantee that benefits passed on to the consumer are actually warranted as the necessary load switching equipment on the consumer's premises may have failed or been circumvented. Thus ripple control, radio paging, long wave radio and/or RDS-based systems are prone to failure over time.

Consumer initiatives are bound to be more successful. Thus meters will develop a service expansion bus to which consumers may attach a variety of cost-saving, energy-conserving and service-enhancing devices. These devices will draw upon the resources of the meter to provide innovative capabilities and could interact with recognised home automation systems. This bus may also be used by utilities to connect service configuration modules that simplify the logistics of contractual service amendments.

Data simplicity, integrity, accessibility and presentation

It is anticipated that an abundance of raw and incompatible data will increasingly be gathered from a diverse array of networks, communication channels and online meters. Whilst the CIM modelling language will help to categorise and condense this data, the resulting information will lack quality if inconsistencies and omissions prevail.

The tendency to repeatedly add functionality of increasing complexity within meters must be resisted in favour of a few well-defined industry-agreed parameter sets. Ideally, meters should only measure and store data and should not include advanced processing capabilities - which are best kept in the domain of the concentrator or better still, located on a central data server. This gives maximum flexibility to adapt services to emerging requirements without recourse to reprogramming or replacement of meters.

Guidelines for maintaining data quality and integrity are:

- Avoid all forms of embedded tariffs. These can be intentionally adjusted to incorrect values
- Avoid real-time data based on clocks. These drift and can be purposely set to incorrect times
- If time functions must be used, ensure time setting is via an automatic synchronisation means
- Avoid battery-backed data. Data inconsistencies occur as batteries fail or are removed
- Use elapsed time-based roll over logging that is time-stamped upon receipt and never cleared
- Provide numerous roll over event counters for common tasks performed or events recorded
- Include automatic self-scaling profile recorders for all measured parameters
- Include energy import and export measurement to cater for future co-generation initiatives.

Much work still needs to be done to guarantee seamless integration of all data sources into dependable reports and meaningful billing information for direct electronic access by consumers.

Logistic simplicity and lower operating cost

The whole point of moving away from manual meter reading systems is to improve billing accuracy and reduce meter reading costs. The opposite is happening. Utilities are unwittingly becoming slaves to the maintenance of increasingly complex databases that demand perfect and consistent data from a multitude of human-based (error prone) business processes. The promised efficiencies are lost in a host of highly-skilled interventions and management tasks.

The White Paper on service delivery encourages us to search for new and faster ways to provide a better service to citizens. Eleven characteristics of a simple broadcast system [2] adequately provide enhanced service management and revenue extraction through:

- Cost-effectiveness (installation and operation)
- Logistic simplicity, fault tolerance and data redundancy
- Non-proprietary, extensible and ubiquitous deployment
- Multi-service and multi-application capabilities.

Worthy of mention is the IEC 61968-9 committee draft that defines a number of use case actors that share and interact with the operational data systems of a typical utility. These are the:

- Meter technician
- Maintenance scheduler
- Outage management system
- Operator
- Customer
- Customer bill
- Planner
- Meter data manager
- Automated meter reading system

Standardisation activity	WG and/or Std
Standardised mountings and enclosures	STANSA TC62 SANS 1524-3 (draft) PIESA 1106 (FDS)
Universal meter numbering system and rectification of STS numbering limitations	STANSA TC62 STS WG6 (draft) NRS 057 ? IEC NP ?
Standardised data elements, modelling and messages	IEC TC57 WG14 IEC 61968-9 (CDV)
Improved serial data interface for virtual tokens and meter powered communication modems (wireless)	IEC TC13 WG15 IEC 62055-52 (CD)
Industry standard for accelerated reliability testing	IEC TC13 WG13 IEC 62059-31 (CDV)
Standardised short codes and displays for field support staff	STS NP ? Eskom SCAAA9 (v3?)
STS prepayment systems, compliance testing method and tools	STS WG7 (draft)
STS corporate governance and intellectual property policies	STS WG4 (draft)
STS enhancements for step tariffs and water applications	STS WG3 (draft)
STS global key management infrastructure	STS WG5
STS supply group code restoration process	STS NP ?
Standardised commissioning process	STS NP ?
Multi-service meters, service mode selection method and dataset	STS NP ?
Service configuration modules	STS NP ?
Multi function meters: extended quality of service requirements	NRS 047 ?
Integrated consumer activated demand side management facilities	NRS 086 ?
Improved meter sealing methods and technologies	NRS NP ?
Improved revenue assurance tools	SARPA NP ?

Table 5: Meter standardisation activities supporting improved service delivery.

- Meter
- Meter reader
- Supplier.

IEC 61968-9 further defines a number of meter reading and message control types. These are reproduced here as it is expected that our systems will align to these:

- Outage and meter health events
- Customer data synchronisation
- Meter reading and load control
- Customer switching
- Meter installation
- Meter configuration
- Power quality event
- Manual meter reading
- On-demand meter read request
- Historical reading
- Meter disconnect and reconnect
- Billing inquiry
- Real time pricing.

Connecting and integrating all of the pieces

Like it or not, prepayment meters are going online and they are morphing into smart multi-service products. The incorporation of ubiquitous communication channels provides a plethora of new challenges whilst simultaneously opening the door to the cost-effective provision of enhanced services to all types of consumers. How soon these can be introduced in sufficient quantities, and how effective they will be in satisfying consumers' changing needs, depends on the efforts and skills of those involved in the definition and specification of such products and technologies. Table 5 records the standardisation activities already underway towards this goal and includes additional activities that have been identified, but not yet initiated due to a lack of resources.

Promoting global scales of economy

To be truly cost-effective, smart multi-service meters must be manufactured in high volumes. They must therefore be designed to international requirements and standards, and must be capable of negotiating a barrage of international trade barriers and intellectual property hurdles. This depends on an open and dynamic, standards-based development framework, regulated by appropriate corporate governance and intellectual property policies.

The South African meter manufacturing industry has established such structures and now leads the global prepayment industry. It is well served by the following organisations:

- South African Prepayment Meter Manufacturers Association (SAPEMMA)
- Standard Transfer Specification Association (STSA)
- Department of Trade and Industry (DTI)
- South African Electro-Technical Export Council (SAEEC)
- African Electro-Technical Standards Commission (AFSEC)

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Table 6: Members of the South African National Committee of IEC TC13.

Conclusion

At the onset of South Africa's mass electrification programme, Dr. Ian McRae acknowledged [3] that services provided to developing communities had to be of equal standard to those of existing customers. In addition to this, it is now clear that the service delivery expectations of existing and emerging consumers are, and will, continually escalate.

Fortunately, tremendous scope exists to improve the quality of service provided to electricity consumers if the industry manages to focus and direct its evolution via open industry standardisation mechanisms. Emerging smart multi-service meters will then empower utilities to adapt and enhance their business processes and practices to meet the challenge, provided that meter obsolescence planning has occurred.

The rate at which these smart meters will be deployed and the time required to establish meaningful quantities depends on the motivation of key players and the commercial opportunities that arise in this market. If these are inadequate to draw resources from other profitable ventures, then much of the aforementioned will not come into being.

The SANC TC13 committee will provide discussion forums to debate the issues (e.g. gender specific requirements). When necessary the committee will issue calls for proposals and arrange meetings of interested and affected parties.

Annex A. The SANC TC13 team

This is probably an appropriate time to recognise the ongoing efforts of the members of the South African National Committee of the IEC TC13 meter standardisation committee. This committee devotes substantial unpaid time and effort towards the attainment of improved products and services in the electricity metering industry. Contact details are given in Table 6, should you wish to discuss matters of interest with them. New members with appropriate experience are always welcome.

References

[1] White Paper on Transforming Public Service Delivery – Zola Skweyiya, Minister for Public Service and Administration , Sept 1997.

[2] Characteristics of a Simple Broadcast System for use in Domestic Electricity Meters – R Hill, SARPA Conference, 2005.

[3] The Test of Leadership – Dr. Ian McRae, Chief Executive of Eskom 1985 – 1994. Δ

Case study : Implementation of FBE within Sedibeng district

by M Tshabalala, Emfuleni LM; M Shikishi, D Ndugwane, A Ndambe, Eskom; and P Geldenhuis, Midvaal LM

Free basic electricity aims to contribute towards raising the standard of living and to help poor households to have access to basic electricity.

Sedibeng Free Basic Electricity Forum (SFBEF) consists of the district municipality, three local municipalities and three Eskom regions. The forum shares its experiences and challenges within Sedibeng district.

What is free basic electricity (FBE)?

It is a limited amount of electricity deemed necessary to fulfill basic household electricity requirements as determined and funded by the government.

The FBE programme aims:

- To contribute towards raising the standards of living of the poor
- To help poor households to have access to basic electricity.

Through this programme, government provides funding for 50 kWh of free electricity per month to poor households.

Stakeholders

- The government provides direction and funding.
- Municipalities are accountable for the provision of FBE and set the selection criteria within the parameters of the national FBE guideline and within their boundaries.
- Eskom is a service provider for FBE in Eskom areas of supply.

Funding agreement

- The cost of the free allocation (FBE) is funded through the equitable share from government.
- Municipality (funding) selection criteria
  - Indigent policy
  - Blanket approach
- Funding agreement
  - Service level agreement between the municipality and Eskom as the service provider in Eskom supplied areas
- Billing
  - Monthly bills are submitted to municipalities
  - Payments are expected to be made within 30 days and overdue accounts are subjected to interest

Registration and access

- Council resolution – decision taken by executive mayor and councillors.
- Policy – indigent or blanket approach.
- Registration – customers bring along ID numbers, electricity meter number, account number, physical address, contact numbers and last token purchased.
- Conventional customers – 50 kWh is credited to the customer bill at the end of the month.
- Prepaid customers – collect their 50 kWh free token from the vending station.

Hints and tips on FBE

- The free units must be collected monthly. If not collected they will be forfeited.
- FBE units do not accumulate on conventional meters; therefore they cannot be transferred from one month to another.
- Free electricity will be valid until all has been used.
- FBE units can be collected at local vendor.
- Always check tariff code and supply group code when collecting token.

Communication strategy

Municipality

- Councillors briefing
- Ward and block meetings
- Community structure involvement

Eskom

- Pamphlets
- Vendor training
- Customer forums
- Awareness campaign

Highlights and lowlights

Highlights

- Roll-out within the district has been successful.
- Emfuleni and Midvaal rolled out after signing funding agreements.
- Payment level is very good.
- Good stakeholders relations. The communication between Eskom and Sedibeng District is excellent, performance meetings are held on a monthly basis to discuss beneficiaries, configuration, token collection, challenges, payments to Eskom and other related issues.

Lowlights

- No roll-out within Lesedi boundaries.
- No indigent register in place.
- Token collection very low in Eskom area.

Challenges

Data

- Data from municipality is not aligned to Eskom systems. Municipality collects data using erf number or stand number while Eskom needs an electricity meter number.
- Data accuracy on our systems, both Eskom and municipality. This is influenced by the move in / move outs and meter changes that are not updated on the system.
- Data standards not common.

Customers

- Customers relocate with meters. Customers who paid connection fees, feel the meter box is their asset, hence they remove the meter when they relocate.
- Tampered meters.
- Illegal connection.

Vending system

- Technologically challenged. Vending machines cannot auto-vend magnetic tokens
- Vending machines availability and security. Availability within the 5 km radius is compromised due to theft and vendors closing down for security reasons.

Way forward

Data

- Data collection projects from both stakeholders. Revenue protection to collect data when they do field audits.
- Standardise data templates and standards within our systems.
- Municipality to verify the illegibility of registered customers.

Customers

Technical solution to

- Minimise illegal connections
- Tampering
- Enforce by-laws

Vending systems

- On line vending
- Roll-out latest vending software – 10.58 version is able to generate auto-vend on magnetic and keypad.
- Vendor training - how to generate FBE magnetic tokens
- Mobile and MTN SMS vending. Will only issue FBE tokens, no money involved.

Conclusion

The stakeholders have a responsibility towards their constituencies to attract, educate and effectively implement these kinds of initiatives to ensure development and poverty alleviation.

Acknowledgement

Sincere thanks and gratitude to Sedibeng FBE Forum members for their dedication and commitment in contributing to the success of the Forum and compilation of the paper. Δ

Pilot testing and findings of the Homeflex project

by Vashna Singh, Eskom

This paper explains the objective of the residential time-of-use tariff (Homeflex) project, the background to the project, the market drivers that support the project and the pilot objectives. It describes the details of the pilot tests that were conducted. The data evaluation, analysis and findings of the pilot tests conducted in Tableview (Cape Town) and Sandton (Johannesburg) sites are also discussed.

Eskom identified the need for a time-of-use tariff for residential customers more than eight years ago. Since then, a tariff (Homeflex) was developed and various pilot projects were run. At the same time various other load management and efficiency strategies were also being studied and tested in the market. These load shifting technologies were not integrated with the tariff.

Due to the changes in the wholesale electricity pricing system (WEPS), Eskom's integrated strategic electricity plan (ISEP), the electricity supply industry (ESI) and the electricity distribution industry (EDI), the above tariff became outdated.

Considering internal and external transformations which have taken place, a revised business case for the Homeflex project was approved by Eskom Distribution.

The revised business case recommended a strategy of piloting a Homeflex tariff similar to the structure of the WEPS tariff together with an automated load management device (geyser control) that would be provided to the customer as part of the Homeflex package.

A residential time-of-use (TOU) tariff was tested at various sites around the country over the period 1998-2003 (inclusive).

The objective

The objective of the Homeflex pilot project was to develop and introduce a residential time-of-use (TOU) tariff that would penetrate the market and provide incentives and benefits to the customer, which would ultimately result in the optimisation of the country's peak demand curve profile.

Market support

The following are market drivers that support the implementation of the Homeflex package:

- The continued increase in Eskom's peak demand and requirements for increased capacity decisions that need to be made.
- The distributor's requirement for increased sales in off-peak periods.
- The Energy Policy White Paper stipulations for cost-reflective tariffs, differentiated capacity charges and sophisticated tariffs for the upper market.
- The increased customer needs for flexibility and lower costs, which ultimately increases customer satisfaction due to reduced bills and more value-adding options.
- The strong differential in the tariff's peak to off-peak ratio encourages customers to shift, which can reduce the distributor's purchase costs and increase profitability.
- There is an increased incentive to shift load.

The Homeflex tariff is designed on WEPS principles, creating a better alignment of the tariff to the WEPS.

This serves to accurately reflect the cost of energy generation and consequently provide pricing signals that would reduce the purchase costs, thereby resulting in improved net contribution for the distributor.

The Homeflex pilots

The objectives of piloting

The primary aim of the pilot studies was to determine whether a time-of-use (TOU) pricing signal would encourage customers to shift their electricity consumption from peak to off-peak periods.

Other aspects that were tested in the pilots were the customer's acceptance of and response to the tariff and load management technologies, and Eskom Distribution's support structures' ability to handle the Homeflex tariff.

The support structures involved in the pilot tests included metering, billing, customer contact centre and field services.

The pilots

The following sites were tested: Sandton (Johannesburg) and Tableview (Cape Town).

Also an unspecified area in Durban, piloted in conjunction with eThekwini Electricity. The analysis of the Durban site data will not be reported on in this paper.

Each site consisted of a control group, a two-part TOU (TOU2) sample, and a 3-part TOU (TOU3) sample, with approximately 50 consumers per category at each site, making an experiment total of 450 consumers.

All of the consumers on the Homeflex pilot tariffs were retrofitted with load management devices which were either timers installed to the hot water storage heaters (geysers), or centrally switched radio ripple-control devices.

The hot water storage heater system (HWSH) was programmed to switch off customers' hot water storage heaters during the morning and evening peak periods.

Customers were given continuous education on how to manage the tariff as well as other energy efficiency information.

Site	Count per category	Analysis potential
Durban	60	Summer 2000, Winter 2001[3]
Sandton	41	Winter 2002, 2003 Summer 2002
Tableview	50	Winter 2001, 2002, 2003 Summer 2001, 2002

Table 1: Summary of experimental source data available for analysis after filtering.

Consumers targeted by the tariff

Characterisation of consumers with HWSH

Data collected in the last 10 years by a national domestic load research project in South Africa [1] was checked to estimate the penetration of hot water geysers in communities with different levels of consumption.

Fig. 1 illustrates the findings. Each point represents aggregate measures from groups of 60 or more households at a research site over a year.

The relationship between consumption and HWSH penetration in the region of 500 kWh can be modelled as a step function.

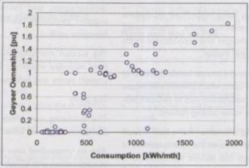

Fig. 1: Relationship between HWSH penetration and consumption in communities (Source NRS LR Project 1994-2003).

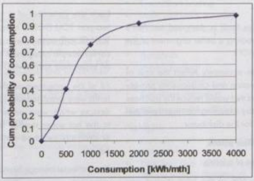

Fig. 2: Cumulative probability of average monthly consumption for Eskom "Homepower" consumers, year 2002.

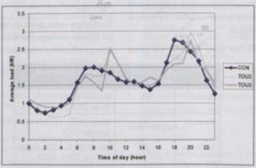

Fig. 3: Average high-season weekday profiles for mid-range consumers in Tableview, 2002.

This relationship implies that if a geyser-activated tariff is applied to consumers with less than 500 kWh/month aggregate consumption, then diminishing returns will result.

Potential audience of Eskom domestic consumers

From an Eskom point of view, small and medium domestic consumers on conventional meters (i.e. the "Homepower" tariff) are all potential targets for this type of tariff.

An analysis of these Eskom consumers is presented in Fig. 2. About 75% of these Homepower consumers used 1000 kWh per month or less over this period. The potential audience for such a tariff may therefore be the proportion of customers who use 500 kWh/month or more. This constitutes about 60% of this customer segment (113 000 consumers) [2].

Technical evaluation of sites

About 52 000 hourly load readings were collected during the course of the pilot project on to a project database at Eskom.

The data resource

All pilot/control site data was filtered to exclude consumers with incomplete data; consumers on a 'special' TOU tariff at Sandton; periods of change where the state of the sample/control experiment was uncertain and after filtering, the data set shown in Table 1 was usable.

Indications of profile modification

An investigation was carried out to identify the difference in load profile (sample versus control) between consumers with the same levels of consumption, and to test the significance of the causal variables (tariff, TOU).

For this purpose, sample and control consumers were binned according to discrete ranges (i.e. bins) of consumption over the same time period for each site to derive an average profile for consumers with or without 2-part or 3-part TOU.

The widths of consumption-bins were chosen specifically for each site in order to maximise the certainty of results at each location.

During this process, it became apparent the sample design of the experiment was marginal and any attempt to bin consumers led to a rise in levels of uncertainty.

Aggregate profiles were generated for consumers in each bin and tariff:

- hour (time of day)
- day-type (weekday/weekend)
- season (high/low), as defined by the tariff.

The differences between the control, TOU2 and TOU3 tariffs in the different periods were also used to investigate the relative effect of the tariff on the household profile at a given time of the day.

These analyses were based only on the comparison of profiles for consumers in the similar consumption classes, and ignored the effect of the tariff on energy consumption.

Fig. 3 shows the measured response for mid-range consumers in Tableview, during

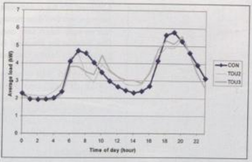

Fig. 4: Average high-season weekday profiles for mid-range consumers in Sandton, 2002.

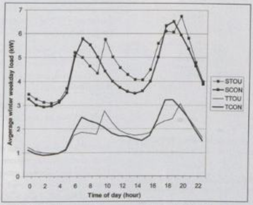

Fig. 5: Modelled average high-season weekday profiles for all consumers for Sandton (S) and Tableview (T), 2002.

high-season, 2002. Aggregate consumption at this site was about 900 kWh/consumer/month, and peak time shedding at this site was effected by radio control.

Figs. 3 and 4 show load profiles that have been normalised to the consumption of the control group at each location. The figures show the control group (CON), 2-part TOU group (TOU2) and 3-part group (TOU3).

Differences between control and TOU2/TOU3 groups are distinct. About 0,8 kW/consumer appears to have been shifted from the average Tableview peak periods, giving a 30% reduction.

The different responses to TOU2 and TOU3 at this site are not distinct.

Fig.4 shows the measured response of mid-range customers at Sandton during high-season, 2002.

Aggregate consumption at this site was 2200 kWh/consumer/month. The HWSHs of Sandton consumers were controlled by local timers. These timers could be over-ridden by the consumers. Therefore it is possible that shedding times were diversified by the consumers, in order to better suit the living habits of their households.

About 0,8 - 1 kW/consumer appears to have been shifted from the average Sandton peak periods – a 20% reduction.

Again, the different responses of TOU2 and TOU3 at this site are not distinct.

Time-slot	Average peak reduction [kW/consumer]	Average peak reduction [kW][4]
7-8	0,76	86 735
8-9	0,70	79 959
9-10	0,57	64 635
18-19	0,72	81 713
19-20	0,71	81 223

Table 2: Estimated impact on national peak, during average high-season weekday.

Also apparent in this sub-set is a poor indication of recovery of the shifted energy at evening peak after the HWSH load was restored. This is an indication of noise associated with low sample numbers.

Variance between the load profiles of consumers of a similar annual consumption is appreciable, and this carries important implications for sample design of such domestic consumers.

Findings of the data evaluation

Effect of TOU2 versus TOU3

Our analysis of this data indicated that the effect of TOU2 is indistinguishable from TOU3. Analyses of the difference between the tariffs show that the variant of TOU used is statistically insignificant.

This is consistent with research which shows high-end consumers are relatively inelastic to changes in the price of electricity as a group.

The effect of TOU versus non-TOU

We found the effect of TOU versus non-TOU to be statistically very significant, which suggests that most of the profile modification witnessed were simply due to the operation of the shedding devices installed on the consumers' HWSHs.

Effect of TOU tariffs on energy consumption

Historical sales data from consumers at the sites was correlated with the load profiles on the Homeflex database, and before/after tests were run to ascertain what effect (if any) the onset of the tariff had on the consumption of electricity.

The change in consumption solely due to onset of TOU2 or TOU3 was found to be statistically insignificant.

National effects modelling

A generalised load model was assembled to estimate the effects of load shifting on the national load, and on revenue from these consumers.

Consumers were divided into two groups, for the Tableview and Sandton sites: control consumers and consumers subject to TOU.

Data was then extracted for these consumers over the entire Year 2002, as this was the time interval when load control devices (of some form) were installed and active at each site.

This data was then aggregated into a mean annual load profile for consumers with and without TOU at each site.

Using the control and the pilot consumer groups at each site, a linear interpolation

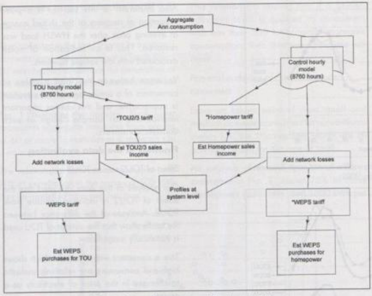

Fig. 6: Scheme for evaluation of the domestic TOU.

model was built between these two groups of customers, at each time of day over the entire year 2002.

Therefore 8760 hour models were assembled for each of the pilot and control groups.

The model has the following shortcomings, but was indicative of the underlying shape functions which are primarily related to consumption levels.

- East/west displacement and differing climates of these two sites
- Central controller versus timer controller
- Differences in Saturday response at the two sites.

Using this model, the typical response of a group of TOU consumers at any arbitrary consumption level can be quickly estimated (given the normal concerns about extrapolation outside areas of applicability).

Fig. 5 shows the estimated pilot and control profiles of the two pilot sites after modelling. Fig. 6 illustrates the evaluation process in which the hourly load profile models were used.

The following method was used to evaluate the effect of TOU sales and consumption at national levels:

(a) The annual hourly profile model for TOU and control groups was used to estimate a consumer-group profile using aggregate consumption as a variable.

(b) TOU and control sales at the LV side were estimated based on TOU and Homepower tariff models, applied to the result of (a) above.

(c) Network losses were added to the results of (a) above to estimate load at the bulk level.

(d) Apply WEPS PSO pricing to the result of (c) above to arrive at "cost" for the bulk supply to these customers.

(e) Present the results.

The model has been used to estimate the effect of Homeflex on sales, purchases, and system demand at various times of the year.

The results from the model indicate that the impact of the tariff at a national level is marked, as is shown in Table 2. The table shows that on an average weekday, between 64 and 86 MW may be shifted out of the peak periods during the high season.

During low-season weekday, this reduction in demand reduces significantly, and may be about 60% of this figure.

Possible implementation strategies

From the pilot tests it was noted that the current Eskom Distribution business can support the implementation of the Homeflex tariff.

There is however some concern regarding the metering technologies, the capital costs of the meter and the metering and billing integration mediums.

With the vast amount of technologies, products and packages available in the marketplace, investigations into the metering, load management and billing aspects required for implementation have already begun.

Numerous cutting-edge metering, billing, load management and data management products have been identified at competitive prices.

A request for an automated metering, load management and data management proposal has already been sent out to the market. This Request for Proposal is currently being evaluated by Eskom Distribution.

The selected technologies will be tested for implementation readiness, system integration, solution performance and customer acceptance in a Proof of Concept phase which is planned for the last quarter of 2006 and early 2007.

Conclusions

Homeflex may be usefully practised on consumers using more than 500 kWh/month. The potential market for this tariff in Eskom is thus about 113 800 consumers, with aggregate consumption of about 1232 kWh/month.

The difference between responses to a 2-part or 3-part residential Homeflex tariff was not distinguishable, but was distinguishable from the control groups.

The introduction of a residential Homeflex tariff did not appear to change levels of consumption.

An hourly load model was established in MS Excel and used to estimate the response to Homeflex for a defined group of Homepower customers. The estimated national network effect of Homeflex was to move 65 to 87 MW out of the morning peak period and about 81 - 82 MW out of the evening peak period.

It may well be that it is the tariff that is the glue that keeps the load shedding devices in place, operating normally and untampered.

In order to make a load management strategy most successful, the customer must see direct benefits. A time-of-use tariff is an extremely effective strategy that provides immediate incentives to the customer to do load shifting, thereby reaping direct benefits.

Acknowledgements

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- Andrew Berrisford, Berrisford Power Management Services
- Hendrik Barnard, Elexpert
- Shirley Salvoldi, Eskom

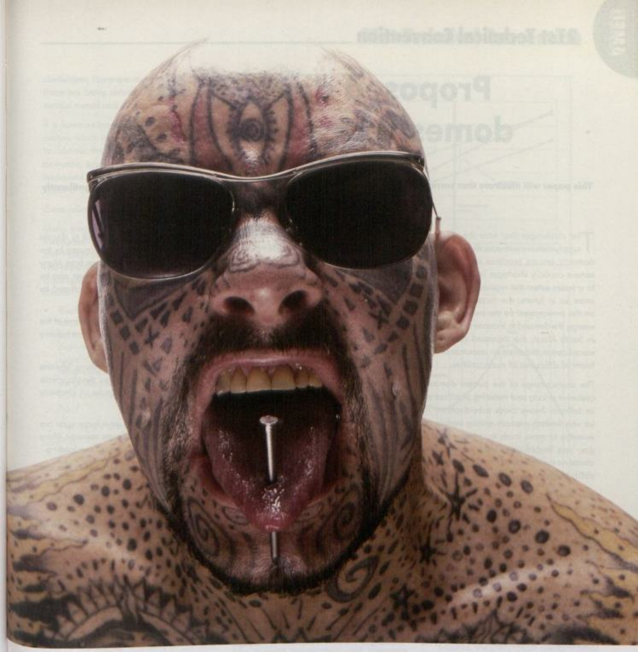
Notes

[1] The NRS load research project

[2] Source: Eskom Homepower (C1,C2 and C3) customer sales, over year 2002. Source data drawn from Eskom sales database (CRP), Aug 13, 2004.

[3] Potential at this site is limited by uncertainty surrounding early tariff data of 1998, 1999.

[4] Eskom Homepower customers only (domestic) 2003. Δ



Proposed direction for domestic customer tariffs

by Hendrik Barnard, Elexpert

This paper will illustrate that current domestic pricing practices are far from optimal and are contributing significantly to some of the biggest problems in the industry.

The challenges that face the electricity supply industry with specific reference to domestic pricing practices are as follows: serious capacity shortages in the Cape and to a lesser extent the region, now and even more so in future; the increased pressure on the environment by the increased use of energy; the demand to increase electrification in South Africa; the increased cost of grid electrification; the strain on resources and the financial difficulties of municipalities.

The shortcomings of the current domestic customer pricing and metering practices are as follows: heavy cross-subsidisation; no (or very limited) capacity pricing signals; no incentive to move loads to cheaper times of day; very limited utility load management; almost no customer load management and no ability to effectively further manage loads.

It is possible to address these problems through the application of new pricing practices; applying the principle of limited capacity supplies for subsidised tariffs; tariff structures more closely reflecting the true cost behaviour and thereby increasing attractiveness of certain alternatives; applying capacity charges; applying time-of-use tariffs and assisting customers with technology to manage their loads.

The technical features required to implement the above can be addressed with some of the new AMR systems now being launched and tested in South Africa: These include the ability to measure capacity and limit the capacity on a fixed per year basis or more dynamic time basis; ability to apply time-of-use tariffs; the option of applying peak day withdrawal tariffs where the tariff time periods can be set dynamically and assisting customers with load management.

Finally utility engineers and accountants should know how these practices will be beneficial to them. Although short-term revenue may drop somewhat, monthly and yearly load factors will increase drastically, thereby delaying massive network capital expenditure and reducing tripping and low voltage problems.

This will lead ot an overall reduction in customers' energy bills, leading in turn to increased disposable income and increased electricity usage during low tariff periods.

If, today, we were to ask any councillor or city engineer if they percieve a problem with domestic tariffs or practices the answer would probably be "No". This really illustrates the magnitude of the problem. It is said that once a problem is identified and accepted a start can be made to address it.

Problem indicators

Industry is facing many problems and challenges. It is not the objective of this paper to try and detail all of these but to discuss those issues which are directly caused by the sub-optimal domestic pricing practices. Many of the other challenges will, however, also be addressed through the solution offered by optimal domestic pricing practices.

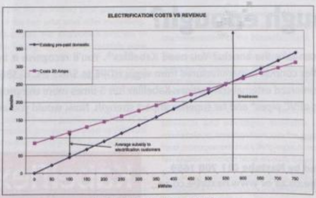


Fig. 1: Electrification costs vs. revenue.

The following statements illustrate some of the serious symptoms which suggest that industry is facing major challenges:

- In various areas in Johannesburg, Tshwane and other municipalities developments cannot go ahead because of electricity capacity shortages.
- Power interruptions on a large scale are becoming more and more common. Many of these due to equipment overloading.
- Major capital expenditure projects are being undertaken to increase capacity in existing residential areas such as Soweto.
- Payment levels in many areas are still as low as 40%, as has been the case for more than five years.
- Many municipalities are still under serious financial constraints.
- There is the ongoing call for increased employment.

The following are indicators of the challenges that we face now and in the future:

- Serious capacity shortages in the Cape and to a lesser extent in the region, now and even more so in future.
- Pressure on environment via increased energy use.
- Demand to increase electrification in South Africa.
- Increased cost of grid electrification and strain on resources.
- Need to reduce prices for industrial customers in order to stimulate industrial growth and job creation.

Industry challenges

The question arises as to what is causing these challenges. There are many causes. Most of these are being debated and addressed by various means and strategies.

It is however feared that one of the biggest causes, which also has the biggest potential to address the problem, relates to current domestic practices which are not being addressed. The following practices are the cause of a major part of the problem:

Cross subsidisation

Many people react when this subject is mentioned. They should all calm down. The plan I propose will not increase the electricity cost to the majority of customers. The domestic cross-subsidies which exist in the ESI are as follows:

- *Electrification customers.* It is a known fact that capital and operating costs are subsidised by government and other customers to low usage customers. The current subsidy levels are considered reasonable and sustainable. However with the growing base it is very likely to become non-sustainable. This is illustrated in Fig. 1.

  The current breakeven for electrification customers on the single energy rate of Eskom is more than 500 kWh/month which is way more than the current average consumption of about 100 kWh/month.

- *Normal domestic customers:* The majority of these are subsidised to the extent of about 30%. This is illustrated in the Fig. 2. The average consumption for these customers is more than 750 kWh/month. The detailed cost breakdown will be discussed lgter in this paper.

The exact levels of cross subsidisation differ significantly between different utilities but Figs. 1 and 2 illustrate the typical situation.

Lack of capacity pricing signals

One of the biggest problems in domestic pricing is the lack of capacity pricing signals and practices. The majority of municipalities provide 60 A, 1 phase or 60 A 3-phase supplies to customers. In various cases such as Eskom, 20 A is used for new electrification customers.

In most cases the connection fees are differentiated between these different supplies. In the majority of cases the tariffs are however the same. Some do have a slightly higher basic charge which emulates the increased metering and administration cost of 3-phase supplies.

Before 1994 a large number of municipalities, especially in the Cape, were applying capacity charges in R/A/month based on installed capacity. Most of these were abandoned in

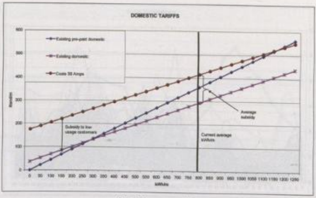


Fig. 2: Domestic tariffs.

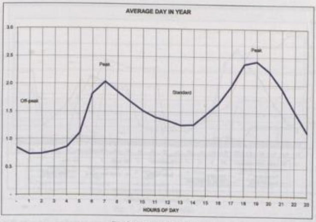


Fig. 3: Average day in year.

the 10 years since. This was mainly driven by the ideology of having the same tariff (equity), for all.

Many of these municipalities have over the last few years realised the problem with this policy and have, at least, reintroduced a basic charge. In most cases however they are still not differentiating by capacity.

The current installation and metering methodology presents some implementation problems:

There is no warning system for the customer. When the supply capacity is exceeded, the circuit breaker will trip. The customer then has to run around to get it switched on.

When the customer is not at home, damage such as rotting of food in fridges can be incurred:

- There is no assistance to help the customer in staying within the installed capacity. It is therefore simply easier to allow a much bigger supply in order to solve the hassle for the customer.
- With prepayment meters the circuit breaker is in the meter, which is usually in the house, and is therefore easy for the customer to reset. In the case of some new prepayment meters, the meter will self-reset after a while. A large number of trips will eventually decrease the circuit breaker life, increasing the cost to the utility.
- In the case of many conventional meter supplies, the utility circuit breakers could be outside the house, the stand or even on a utility pole or in a utility distribution box which is inaccessible to the customer. The utility will then have to come out to reset the circuit breaker.
- In many cases the customer will have his/her own circuit breaker to limit the load. The problem with this is that in many cases these are not set by the customer at the appropriate size or the trip differentiation between the customer and utility meter is not effective thereby still causing the utility circuit breaker to trip.
- The biggest problem with this is the bypassing of prepayment meters and self-upgrading of circuit breakers being

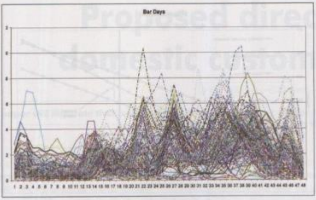


Fig. 4: Bar days.

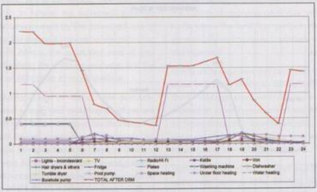


Fig. 5: Simulated profile.

done by customers when they experience a capacity problem.

It is clear that the current methodology and technology does not lend itself to effective capacity management. Despite all of this, some utilities are doing it to a reasonable level of effectiveness.

This paper will later illustrate how these issues can be addressed.

Lack of load shift incentives

There is currently no incentive for domestic customers to shift loads to the cheaper times of the day, except for a few domestic customers on pilot projects.

Recent power problems in the Cape have clearly illustrated that there is significant load shift potential for domestic customers.

The load shifting by all customers, but specifically by domestic customers during evening peaks, has been so extensive that the load profile for the Cape over that period almost became flat.

This load shifting by customers caused significant inconvenience because everything had to be done manually - no automated equipment was installed. Despite this, many customers indicated that it was not so bad.

In France, domestic customers on TOU tariffs, where significant load shifting assistance with technology is provided to customers, the domestic peak is outside the normal domestic peak time.

In other words the profile has been inverted. They do the following:

- Apply TOU tariff with significant differentiation in rates between the various periods.
- Their TOU tariff also features a so-called peak day withdrawal tariff where for 22 days in the year, which are determined 24 hours before the time, the rates will increase as much as 10 times during the very cold spells.
- From the meter a set of contacts is provided which switch as follows: on at all times of the day; on only during standard and off peak; and on only during off peak times.
- Using these contacts the customers can wire their houses to the various applications.
- Space heating is largely done with gas. During the past few years electricity usage has increased because of some EDF surplus capacity, but in many cases these customers use some form of staging device, allowing minimum usage during peak times.
- The majority of households cook with gas. Ovens are still mainly electric.

We know of the experiences and troubles that Eskom and other utilities have had in making TOU successful. Later in this paper it will be shown how this can be done.

The bottom line is that the majority of domestic customers in South Africa are not applying any load management strategies.

No ability to effectively manage during a crisis

There is no ability to manage loads during a major power shortage crisis. The only means in some areas is the limited utility geyser control and the "call on the public" method used by Eskom in the Cape.

If other mechanisms do not exist the only means to reduce demand are:

- To reduce the voltage on domestic networks. This reduced voltage reduces the largely resistive loads of domestic customers. This however is not always possible because of low voltage problems already existing all over the network, automated equipment to do this is not installed and such decreased voltages for more inductive loads will cause problems.
- Interrupting selected areas. This is extremely disruptive to customers, causes many other problems such as violence, accidents, lost productively, etc. It also requires a significant amount of work for utilities without the necessary SCADA systems.
- To call on customers, using the media, to reduce loads. The main problem with this strategy is that some customers contribute to a large extent whereas others simply don't give a damn. Those customers who go to the effort are not compensated and those who don't are not penalised. Over longer periods of time, this will become unsustainable because no one will comply.

This paper will later illustrate how demand can be managed effectively and fairly during times of serious capacity shortages.

Lack of use of alternatives

One of the biggest problems caused by the cross-subsidisation of domestic tariffs is that it makes alternative energy sources uncompetitive.

The Electricity Act makes provision for the application of cost-reflective tariffs which will promote the efficient applying of energy sources with due consideration for environmental effects. Our industry is failing this requirement in spades.

Some examples:

- Solar heating, which is considered one of the most environmentally-friendly methods of heating water, is almost nonexistent in South Africa. If electric water heating was priced cost-reflectively many more solar systems would be installed. It is however appreciated that the cost is significant when these loads are managed from a national capacity and local network capacity point of view. These practices make electricity water heating much more competitive than solar heating.
- Cooking with gas is much more effective and efficient than with electricity. With electricity, especially in poor households, the losses are very high due to use of old, cheap and ineffective appliances, use of old, damaged and non-sealing containers and poor practice such as leaving pot lids open, always selecting the highest setting on the plates, etc.
- Space heating with electricity is one of the most wasteful applications of electricity. In a coal-fired power station coal is crushed and burned to create heat Then water is heated to create steam and the steam is run through a turbine to create kinetic energy and a large portion of the energy is lost to condensation. Then the turbine turns the generator to create electricity and the electricity in transformed to high voltage, then it is transmitted all over the length and breadth of South Africa. It is transformed down to low voltage again and, finally, heat energy is created again in an electric heater!
- The total efficiency of this process is less than 20%. In other words less than 20% of the calorific value of the coal ends up as useful energy in the house. This might be acceptable if there were no other alternatives. What makes this problem even worse, compared with other applications such as cooking, is the small number of hours it is required in a year.

Energy efficiency

The current low tariffs also cause very limited energy efficiency practice being applied: with a low electricity price, the cost of converting

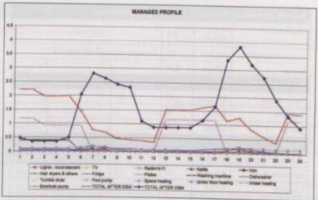


Fig. 6: Managed profile

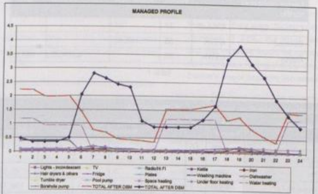


Fig. 7: Managed profile

to more efficient appliances is not warranted in many cases.

Because TOU tariffs are not applied, the applications in peak time such as lighting are not nearly as attractive as they should be.

High non-technical losses

There are still many areas where non-technical losses are very high. This remains one of the biggest causes of financial problems in municipalities.

This is not only in respect of electricity but also applies to water services.

In the majority of prepayment areas the non-technical losses are still at least 10%; in many of the old townships the payment levels are still as low as 40% and current technology and methodology just does not seem to be able to solve the problems.

The limited features of meters

Current meters being used for domestic customers have very limited features for the utility and for the customer. Their function is to read electricity consumption or make prepaid electricity available. Their shortcomings are as follows:

- They offer limited feedback to the utility - prepayment meters have no regular feedback. Utilities study the purchase patterns of customers, but that has no direct relationship with consumption. The premises need to be visited in order to access the meter, where a cumulative consumption reading can be taken from certain meters. Some meters will then also indicate if bypassing has taken place.
- Conventional meters are visited by meter readers once a month or at least every three months. This at least gives a regular feedback of the consumption. It does not however indicate when the consumption took place or any other information.

This paper will later reveal how this is hindering progress with the application of optimal practices.

Recommended strategy

The above challenges can be addressed using the following strategies:

- Apply limited capacity supplies for subsidised domestic consumers.
- Apply highly cost-reflective tariff structures and levels for all other domestic customers.

Typical variables	Domestic excluding electrification				
Capacity	Amps (ADMD)	18,5	3,7 kVA		
Installed capacity	Amps	50	Capacity required not installed		
Energy	kWh/m	819			
Current tariffs		**Prices**	**Fixed cost**	**Variable cost**	**Total**
Basic charge	R/month	37	37		
Capacity	R/kVA	0	0		
Energy	c/kWh	32		262,08	299,08
Costs		**Prices**	**Fixed cost**	**Variable cost**	**Total**
Customer service	R/month	8	8		
Administration	R/month	12	12		
Capacity	R/kVA	32	118,4		
Energy	c/kWh	30		245,70	384,1
Large customer tariffs		**Prices**	**Fixed cost**	**Variable cost**	**Total**
Customer service	R/month	37	37		
Demand	R/kVA	55	142,45		
Energy	c/kWh	25		204,75	384,2

Table 1.

Electricity - medium houshold			Winter month				
Application	**% of house**	**Nr**	**Capacity**	**Daily hours**	**Duty cycle**	**kWh/m**	**Cumm kWh/m**
Incandescent lights	100%	10	50	4	1	61,00	61,00
TV	100%	1	250	5	1	38,13	99,13
Radio/Hi Fi	100%	1	50	6	1	9,15	108,28
Kettle	100%	1	2000	0,5	1	30,50	138,78
Iron	100%	1	1500	1,5	0,3	20,59	159,36
Hair dryers & others	100%	2	1000	1	0,7	42,70	202,06
Fridge	100%	1	250	24	0,3	54,90	256,96
Plates	100%	1	2000	2	0,5	61,00	317,96
Oven	100%	1	2000	1	0,5	30,50	348,46
Washing machine	100%	1	2000	2	0,5	61,00	409,46
Dishwasher	50%	1	3000	0,5	0,5	11,44	420,90
Tumble dryer	50%	1	3000	0,25	0,8	9,15	430,05
Pool pump	40%		800	6	1	58,56	488,61
Space heating	70%	1	2000	5	0,8	170,80	659,41
Underfloor heating	20%	3	500	24	0,4	87,84	747,25
Water heating	100%	1	3000	24	0,2	439,20	1186,45
Borehole pump	10%	1	700	3	1	6,41	**1192,86**

Table 2.

These should include basic charges to reflect the fixed service/administration costs; capacity charges reflecting the customer's required capacity; TOU energy rates as close as possible to bulk tariffs; peak day withdrawal rates and reduction in capacity during major capacity shortage times.

- Assist customers with advice and technology to be able to move loads to cheaper times; reduce the maximum required capacity; apply energy efficiency measures; switch to alternative energy sources if appropriate and continue utility geyser load management - but in line with the national control capacity requirements to maximise the value to the utility/customer.
- Offer incentives to customers to manage their geysers to enable the application of more aggressive switching.
- Reduce non-technical losses through better information about consumption, power outages, and losses per areas and then target the associated problem areas.

This may sound easy, but there are many questions that need to be answered:

- Will it really work?
- Will it really make a big difference?
- Is it practical to implement?
- What are the costs/benefits?

Cost vs. current prices

Many will probably say that this is an impossible pipe-dream. I will try to illustrate what I mean and how it is possible.

I will start with an illustration of the true cost of supply.

The whole cost analysis process will not be illustrated because of time constraints and the fact that many of the issues are well known.

The analysis of cost will focus on the analysis of the load profile. The analysis was done using half-hour profiles of some individual customers and grouped domestic customers from various municipal areas in various regions of South Africa:

- 20 000 customers
- 819 kWh/m
- Annual load factor 30,35%
- Peak demand (ADMD) = 3,7 kVA.

It would be agreed that this represents a pretty average (non-electrification) customer. The consumption is, if anything, on the low side. The profile shown in Fig. 3 is similar to what is usually presented at workshops and conferences. This shows an average peak demand of 2,3 kVA ADMD.

For a typical domestic customer, however, the maximum demand is much higher, typically 8 to 16 kVA as is illustrated by the individual customer load profile in Fig. 4. This shows a peak demand of 11 kVA.

It should be understood that this is a 'before-diversity' profile and the effect of diversity from the individual customer up to the mini-substation is very high, as much as 90% of the nation-wide diversity.

The problems with historical tariff designs are that the annual peak ADMD is not used but an average annual peak.

This means that the peak that should be used for cost allocation is understated by as much as 48% - 2,5 kVA rather than 3,7 kVA.

Table 1 summarises the current tariffs against typical costs and typical large-customer tariffs.

Assumptions
All lights converted to efficient
Convert plates to gas
Convert to alternative space heating
The following appliances only used in off peak times: - washing machines, dishwashers, pool pumps, borehole pumps
Tumble dryers in standard day but some hours in morning peak
Water heating: only in off-peak times plus 4 hours standard in day.

Table 3.

Key variables	Before managment	After management	Diff
Ave kWh/month year	966,7928	820,3928	146,4
Ave kWh/month high	1192,855	918,355	274,5
MD at peak time	3,73584	1,275893	2,459947
MD	4,639701	3,663484	0,976218

Table 4.

This shows a cross-subsidy of almost 30%. In this case the tariff for the same profile on the large customer tariff is almost the same.

This indicates that I have been too conservative and that in fact the cross-subsidy is much more, especially if the municipal tax (surplus) is taken into consideration.

Load profile impact

This section shows the impact on customer's load profile of the following strategies:

- Effective energy efficiency
- Load shifting
- Energy conversion.

Table 2 shows the assumptions used to simulate a load profile for a winter month.

Assumptions were then made about consumption of various appliances during different times of the day and the resultant average daily load profile for a winter month was obtained. Note that the simulation was done to yield the same annual peak demand of 3,7 kVA.

Various assumptions were then made in terms of the application of load management, efficiency and energy shifting strategies as shown in Table 3.

The resultant load profile is shown in Fig. 6.

The profile before and after change are compared in Fig. 7.

The key results from the above analysis are shown in Table 4.

When we view this it is clear that domestic customers still need significant capacity but that it can be at times when the networks are lightly loaded due to commercial and industrial off-peak needs.

On the higher voltage networks where there is diversity with these other loads the reduction in peak demand would thus be significant.

Savings - winter			Price		Revenue impact	
	kWh		Existing	New	Existing	New
To alternatives	-231,8		0,32	0,49	-R74	-R114
Efficiency	-42,7		0,32	0,4927	-R14	-R21
Energy shift	-232,9	from peak	0,32	0,62	-R75	-R144
	-197,5	from standard	0,32	0,2381	-R63	-R47
	195,11	to off peak	0,32	0,17	R62	R33
Capacity	-2,46		0,00	45,00	R0	-R111
					-R163	**-R 404**
			Before shift			
Total bill	**Rand/m**		R437	R580	R274	R176
% change	Existing to new tariffs		**R143**	**32,72%**		
	Shift on existing tariff		**-R163**	**-37,33%**		
	Shift on proposed tariff		**-R404**	**-69,69%**		
	Existing to proposed with s		**-R261**	**-59,77**		

Table 5.

Customer impact simulations

Using the analysis above the impact on customers is assessed. The impact for a winter month is shown in Table 5.

During the summer months the saving is much less. Table 6 shows the average for the year.

The following can be deduced from this:

- Few customers would consider the trouble and effort worthwhile for a saving of about R100 per month, which will be the case on the current tariffs.
- Many customers would consider a saving of about R210 per month worth the effort.
- Many customers would participate if they knew they were facing a real tariff increase of 33%. We must remember that this increase would be on top of any real increases facing the ESI because of Eskom's major capacity increases.

I am sure that there would be acceptance for achieving effective load management if these are the kind of results that are achievable.

How to address the issues

In previous sections the many practical problems associated with these strategies were highlighted.

This section will address these issues.

From a practice implementation point of view these objectives can only be achieved by using automatic meter reading (AMR) systems. The name in itself is misleading.

We are really referring to a remote measurement, control and customer interface system because these are the features offered by modern AMR systems.

The objective of this paper is not to advertise AMR systems, but rather to inform you of the features which are required by these systems to allow utilities to benefit from all of the recommended strategies.

If not, only a few benefits will be achieved, thereby threatening the cost-benefit analysis.

The general features of AMR systems such as cost, reliability, accuracy, reliability, implementability, broad base application, application for all kinds of customers, covering electricity and water, possibilities for value-added services, utility network planning features, quality of supply management, etc. will not be mentioned here.

Only the features required to achieve the load management objectives are named. The features required are as follows:

Average/month			Winter	Summer	Revenue impact	
			3	9		
	kWh		Existing	New	Existing	New
To alternatives	-231,8		0,32	0,29528	-R47	-R49
Efficiency	-42,7		0,32	0,30	-R14	-R13
Energy shift	-232,9	from peak	0,32	0,34115	-R54	-R64
	-197,5	from standard	0,32	0,20353	-R63	-R40
	195,11	to off peak	0,32	0,1664	R77	R40
Capacity	-2,46			45	R0	-R86
					-R101	**-R 212**
			Before shift			
Total bill	**Rand/m**		R437	R580	R336	R368
% change	Existing to new tariffs		**R143**	**32,72%**		
	Shift on existing tariff		**-R101**	**-23,13%**		
	Shift on proposed tariff		**-R212**	**-36,53%**		
	Existing to proposed with s		**-R69**	**-15,76**		

Table 6.

- Conventional and prepayment meter option.
- TOU tariffs such as Eskom Megaflex with basic and administration charges; capacity charges (time differentiated); energy charges, including high and low season, peak/standard/off-peak times, weekday/weekend, public holiday, super peak or peak day withdrawal tariff, very high rates, all at dynamic times.
- Capacity tariff management options including overall capacity and capacity at peak times
- Capacity crisis management options in order to achieve a proportionate reduction in capacity.
- Utility load management options including utility geyser control for local network and load control from a national perspective.
- Load management assistance to the customer with information about the TOU periods, available capacity, auxiliary contacts linked with TOU periods and capacity limits.
- Informing customers of various issues including actual capacity being used, actual rate of consumption, approaching exceeding of capacity, remaining credit and consumption, relevant TOU tariff period, reason for trip such as exceeding capacity, automatic reset after trip due to overload.
- Some form of tamper detection with quick feedback to the utility.
- Supply outages being incurred.
- Load profile data.
- Loss data per feeder or substation.

Most modern systems offer these features. Some of them however do not. One of the key design aspects is that the tariff calculations (TOU and capacity) cannot be done cost-efficiently in the meter unless the tariff tables are updated very regularly. This is because of the need for dynamic tariffs where the times and rates can change on the day and thus the large memory and calculation needs required.

Utility impact

Municipal engineers and financial officials probably fear large revenue losses and high costs that need to be incurred. The following facts help address many of these fears:

- The cost of many of the AMR systems is not significantly more than current prepayment meters. This is more so when retrofitting of prepayment meters is considered for existing medium consumption customers.
- The lower electricity bills will be largely matched by savings in the purchase cost from Eskom because of lower consumption levels and more at the cheaper times; massive savings in capital expenditure and reduced trips and equipment failure due to overloading; massive increase in revenue due to reduction of losses; the effective profit for the utility can be increased significantly at the current average price levels due to the major reduction in cost.
- These strategies will make an incredible amount of capacity available which can be used to supply the large demand for new developments (1 to 2,4 kVA per existing house).

In many cases the break-even for the capital expenditure offered by AMR systems and using these proposed strategies is less than one year.

Conclusions

The subject covered in this paper requires a full conference to cover in depth. This paper has as its objective to illustrate to engineers and other municipal representatives that there are alternative ways to solving many of the challenges facing the ESI today.

The case for each utility is obviously different. The networks are different, the customer profiles are different, the costs are different, the types of customers are different and many more.

The calculations for each would thus yield different results. My experience hints that this would be workable for all municipalities. This is so even before any of the other 'softer' benefits have been considered.

I hope this will stimulate thought and debate and that staff will start building these kinds of issues into their strategies for the future. Δ

Applicable training for rural electrification

by Claude Cogill and Mervyn Silber, Industries Education and Training Institute

I would like to introduce you to three people who, less than three years ago, were unemployed, without income and desperate to find something of worth to do with themselves.

These people are now role models in their societies - they have picked themselves up from the throes of despair and poverty, and have elevated themselves to being people of substance and courage.

Local labour job creation for sustainable growth

Catherine Selefo had completed her schooling, had acquired an N3 diploma at a technical college and was exposed to some practical work experience at Eskom. Then it all dried up – a reasonable qualification, some work experience But no employment. She then joined a rural line training programme in the Shaleng village in Delareyville with IETI, completed the full career path, and worked on the Shaleng project. She proved her worth well enough to subsequently be employed by a platinum mine in the region, where she has the position of senior electrical instructor. Her gross monthly salary is in excess of R10 000.

Sepho Mphehlo was unemployed when he joined the rural line programme in the Lichtenburg area. He worked on the project, and has subsequently decided to study further in this career option. He has recently completed his NTC 2 certificate, and has aspirations to work towards an electrical trade diploma. His current income is in between R2000 and R4000 per month.

Daniel Masiga had completed his NTC 4 certificate in electronics at the time of enlisting on a rural line course in Vryburg. He was unemployed at the time. He completed the career path training with IETI, worked on the project in Vryburg, and has subsequently been enlisted as a trainee trainer in similar projects in the area. His current income is in the region of R4500 per month.

The people in these success stories enlisted on a programme similar to the one I will detail later, and started from scratch to empower themselves. The programme began as a rural line electrification project with an electricity distributor, progressed to an entry-level electrical course, that culminated in a basic business skills programme.

The vast majority of participants in the programmes are now either employed in the formal sector, working for contractors or have started their own lucrative and successful SMME business.

The irony of the programme was that it was introduced to electrify the very communities that these people come from – and in the process energised careers for themselves!

The strength of the programme is that it encourages growth from within a particular region, where territorially the immediate region is empowered.

Whilst the programme is not limited to rural areas, the outlying areas are the most under-resourced and are therefore in a prime position to enjoy the benefits of such interventions.

Let's look at the "domino" effect of this system:

An area is electrified > people start using electrical power > there is a sudden demand for house wiring > appliances are bought and / or repaired > there are numerous electrified trading opportunities > services cascade to include SMME development > the cycle goes on and on...

The are many projects rolling out across the country which have similar deliverables as the ones that our three subjects participated in – it may be that they too can deliver the same results.

Unemployment in our country is not on the decline – in fact, it is growing at an alarming rate – with 60% of our current matriculants certain to end up unemployed. All the signs are there that the immediate job prospects are not encouraging, and that drastic, yet plausible and constructive methods need to be employed to turn the situation around.

Let me make a point to alleviate any concerns – what is being proposed is not a "butchered" or "half-baked" intervention that is intended to qualify people overnight. We do not intend setting people up for failure – rather we offer a proposal that meets current demands in society, whilst achieving the ultimate objective of creating sustainable work opportunities.

Also, the interventions recommended are intended to aid or support legitimate training programmes, where the end result will be a formal or recognised qualification for the individual.

Background

The government is fully supportive (and in many cases insistent) on projects taking place in community areas where local labour is employed on such projects. However, in many instances, local labour is not skilled for such projects, resulting in them either missing out on such an opportunity, or else being employed on menial work, leaving them with no sustainable skills once the project is completed.

Our organisation has identified project-linked training as one of our priorities, and in doing so, has ensured the following:

- All training is fully accredited; therefore trainees obtain skills that are linked to nationally-accepted norms and standards.
- On successful completion of training, trainees obtain a certificate that is nationally recognised and their name is recorded on a national register maintained by the Energy SETA.
- Training is linked to an accredited career path, and on completion of the required modules, trainees may leave the training phase and commence work on a project.
- On completion of the project, the trainee may become unemployed once again, in which case he/she may either elect to seek work elsewhere, or continue along the career path up until any stage, even as far as artisan status.
- Training covered in our programmes are not just suited for employment in the "formal" sector, but is also ideally suited for "self employment" (SMME) due to them being exposed to business skills whilst in training.
- Under certain circumstances, our organisation is able to secure funding for the training, and therefore no costs are incurred by the contractor, developers, local councils or the trainees.

Electrical appliance repair

Course content includes:

- Safety aspects related to workshop electricity and appliance repair.
- Basic first aid
- Familiarisation with terminology, tools and equipment used in appliance repair.
- Making off and installing flexible cables and cords.
- Testing, installing and connecting single-phase AC motors.
- Testing and repairing of domestic electrical appliances, including stoves; hot water cylinders; washing machines; tumble driers; vacuum cleaners.
- Testing and repairing small portable electrical appliances.

NB. Minimum entry requirement: Basic electrical modules 0, 1, 2 and 3 or proven electrical experience.

Domestic refrigeration repair

The course content includes:

- Swaging, flaring, forming and joining tubing
- Silver soldering, copper welding and aluminium soldering
- Testing of motor compressor units
- Evacuating and recharging of refrigerant
- Leak detecting
- Fault finding and repair of electrical circuitry
- Fault finding and repair of refrigerant system

NB. Minimum entry requirement: Basic electrical modules 0, 1, 2 & 3

Business start-up programme

The course covers the following

- Registration and orientation.
- Establish the profitability of selected business.
- Prepare a business plan.
- Prepare a marketing plan.
- Present business plan to bankers.
- Develop implementation strategy.
- Keep record of financial activities. Δ

ANNEXURE B

ELECTRICAL RELATED TRAINING
OVERHEAD LINE CONSTRUCTION CAREER PATH

RURAL LINE CONSTRUCTION
(HIGH TENSION – HEAVY VOLTAGE)
11 and 22KV lines
RATIO: 1:15
DURATION: 15 Days
Minimum Entry Required: Grade 9

↓

SUPPLY INSTALLATION OPERATOR
(PRE-PAID METERS & READYBOARDS
RATIO: 1:15
DURATION: 5 Days

↓

ELECTRICAL (Housewiring)
MODULES 1, 2 & 3
DURATION: 20 Days
Minimum Entry Required: Grade 9
This course forms part of the syllabus of the Electrical Apprentice Course and therefore anyone wishing to continue training to become an Artisan will get credit for this portion.

↓

ELECTRICAL APPLIANCE REPAIRING
RATIO: 1:12
DURATION: 25 Days
Minimum Entry Required: Grade 9

↓

REFRIGERATION REPAIRER
DOMESTIC
RATIO: 1:12
DURATION: 10 Days
Must have passed Electrician Modules 1, 2 & 3

↓

START YOUR OWN BUSINESS
RATIO: 1:15
DURATION: 14 Days

Development of technical skills to address the skills shortage

by I N Mabona, Eskom

This paper examines the development of technical skills within the electricity distribution industry (EDI). It seeks to develop a strategy on how best the skills shortage can be addressed.

An overview will be given of some of the current initiatives which when taken together could have a profound influence on the way the industries employ their staff, and the way in which those employees are trained and developed.

"Historical trends continue in the electricity industry sector as it shifts further towards more capital- and skill- intensive forms of production with significant job shedding at the intermediate and low-skill end of the spectrum. The demands of nuclear energy, renewable energy and new gas resources all require more skilled and highly skilled labour inputs." - Andre Kraak

The aim of the work is to develop a skills strategy, analyse causes of skills shortage and how best existing skills can be enhanced to meet the demands that are being encountered by the industry.

Restructuring of the electricity redistribution sector has been undertaken by Eskom and about 415 municipalities. The municipalities collectively service about 60% of total customers by number and about 40% of total customers by sales volume and vice versa for Eskom. The challenges that are currently facing EDI have been within the electricity industry for a number of years.

As a result numerous studies into ESI have taken place over the past couple of years by bodies such as NELF, EWG and the Electricity Restructuring Inter-departmental Committee (ERIC).

The issue has been how to transform the industry so that it meets the government's stated objectives of providing low-cost electricity and high quality service to our growing economy and to our growing population.

Strategy development

As a manager wanting to get the most out of your team, you need to practise people-focused leadership. You need to encourage your people to contribute fully to the success of your organisation and to do that, you need an armoury of people skills.

Except for technical skills, there are skills that you can apply in formal settings, or can use when you are interacting informally and motivating individuals and the team.

As the human capital intensity of products and services, increases the importance of human resources assessments should become a greater part of the evaluation of corporate strengths and weaknesses.

South Africa is a developing country with a large proportion of its people unemployed and possessing very low skill levels. The provision of high-level technical skills is inappropriate as the sole focus of human resource development (HRD). Intermediate skills are also a critical and complementary input on which current economic growth is heavily reliant.

What is required is an integrated and multi-pronged HRD strategy that simultaneously supports the expansion of high skill capacity and high level knowledge production, which will re-invigorate the supply of intermediate skills to the national economy and provide support to low skill job creation initiatives.

The integration of countries into the global economy over the past two decades has meant that the attainment of comparative advantage for individual nation states is no longer forged at the expense of low cost labour or cheap material as was the case during industrial capitalism. It is now done on the basis of high technology skills, high quality and value-adding services.

The skills crisis facing our industry - especially in the professional categories - remains our key challenge.

Skills development

Training and development has been craft-centred or focused on high status work. The training surveys carried out found that, of those employers that developed or trained (one in five did not), no more than 48% of the work force was trained, which meant that over half of the organisation did not benefit from any training or development.

This may have something to do with the divisions between what was called general and specific skills. It is argued that there are two types of development and training a company may carry out:

- General training which results in skills that are not only useful to the company but to its competitors in the labour market, e.g. technical skills, management skills.
- Specific training which results in skills that are of use only to the company e.g. manufacturers of products unique to the company. The industry would be prepared to invest in specific skills because it would benefit from them directly, but not in general skills unless the individual employees paid for their development themselves.

The industry needs to be encouraged to take a wider view when formulating policies including such factors as:

- Job redesign
- Labour market skills
- Motives for development
- Learning from experience
- Recruitment
- Turnover costs
- Labour mobility
- Economic benefits

Some of these issues were raised in a paper by Michael Oatey in 1970. However, it is only now that his suggestions can be seen to have viability through the wider framework, albeit somewhat hidden under the range of schemes currently being marketed by the government through initiatives such as ASGISA/JIPSA.

Development activities are more sustainable when framed within broader HRD and human resource management (HRM) processes. What distinguishes organisations is the richness of the context for training and continuing development that key actors can mobilise.

Some of the factors that contribute to the richness of the context are the importance of the former training agencies and emphasis on financial benefits (return on investment) as well as the context of external pressures by customers in requiring quality.

The significance of quality is that it touches on a fundamental pillar of competitiveness and like efficiency in production, generates criteria that training can rely on.

In conclusion, training and human resource management generally may be seen working on at least two levels:

- Reactive and short term and concerned with avoiding the costs and setbacks associated with not training.
- Developing corporate capability so as to enable the company to perform well immediately and to develop in the future in such a way as to improve its market position.

Somehow training and development has been separated out from the business for special attention. The signs are that the volume of training is improving. Recent surveys show that there has been an increase in the proportion of people of all ages receiving work-related training.

The problem has been that though there have been some very innovative initiatives, their impact has been lost within the sheer volume of events. We are not revolutionary people. I believe that to really affect the changes that are needed we need to be more revolutionary at least in our thinking about the problems of skills shortage and how best we can enhance them with all the opportunities we face.

We are faced with the following challenges:

- Challenge of demography with the numbers of young people declining towards the middle of the decade (HIV/AIDS) and with the associated increase in emphasis on the need for women workers.
- Challenge of competition especially with the open market through globalisation in line with intensification of competition over the past few years.
- Challenge of quality in services as in manufacturing, with the growing use of quality assurance measures such as TQM.
- Challenge of macro projects such as, Coega, Gautrain, 2010 Soccer World Cup for building stadiums.
- Challenge of quality of supply such as plant capacity, plant maintenance, outages as well as ageing of plant.

Skills retention

In order to be able to help EDI in attracting and retaining competent workers, standards need to be designed to identify qualified job candidates, promote career development and to recognise employee achievement. Businesses need to look into educational institutions and other industry associations to better define and develop technical job competencies and work place social skills among the potential job candidates, who have acquired these attributes.

EDI needs to develop and implement a mandatory skills retention strategy that will enable the industry to maintain adequate levels of critical competencies.

Inputs conducted with employees on resignation (exit interviews) could best be used to strengthen the retention strategy.

The strategy should as far as possible oblige the experienced employees occupying critical positions to ensure that they are competent to transfer their skills to less experienced employees.

Point of departure

Although this document seeks to provide a framework for addrssing skills shortages, it acknowledges that skills development occurs largely in the context of occupations and their specialisation.

Research by Anderson and Marshall for the Canadian Department of Education and Employment, as far back as 1996, found that employers define "core skills" as technical skills. They also formulated the term "generic core skills" to refer to the non-technical skills.

Conclusion

The industry needs to acknowledge the importance of technical skills. The declining output of FETs and technikons in providing technically-skilled people must be addressed. Policies and strategies that seek to address skills gaps and shortages need to be implemented. The industry need to effectively establish joint ventures in addressing and eliminating skills shortages.

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'Mean asset life' and its influence on the refurbishment budget

by Robert Wallis, Merz and McLellan; and Sicelo Xulu, City Power

The objective of this paper is to illustrate the importance of the assigned asset life "mean asset life" in the management of the assets in an electrical distribution system. It also highlights the role of the asset manager and the crucial role management tools can play in the compilation of the refurbishment budget.

		South Africa		EDI Toolkit	UK	
Asset class	Asset type	Mean	Std Dev.		Mean	Std Dev.
Transformers	6,6 kV - 11 kV	40	5	45	55	11
	33 kV - 20 kV	40	5	50	60	10
	88 kV - 275 kV	40	5	50	55	11
Switchgear	6,6 kV - 11 kV	25	5	45	52	7
	33 kV - 20 kV	25	5	50	52	10
	88 kV - 275 kV	25	5	50	49	10
Underground cable	11 kV	30	10	45 - 50	76	10
	20 kV - 33 kV	30	10	45 - 50	76	10
	88 kV	30	10	45 - 50	61	9
Overhead line (88 kV)	Conductor	60	5	50	66	9
	Tower	60	5	50	55	5
Protection	Electromagnetic				50	10
	Static				15	5
	Digital				12	3

Table 1: Difference between SA and UK.

Asset registers and the asset valuation

Today we are bombarded with financial jargon that I believe leaves even the accountants confused.

- GAAP – Generally accepted accounting principles
- GAMAP – Generally accepted municipal accounting practices
- IFRS – International financial regulation standards
- GRAP – Generally recognised accounting principles

To those of us without the benefit of an accounting degree it seems as though there is a new set of rules for every new situation, but what does this mean for engineers that are trying to run an electricity distribution network?

Generally, just a lot of personal time swotting up the various new sets of rules. All the rules are for the way in which the accounts are presented and what the assets are worth in financial terms, but contribute very little towards the actual management of the network.

Thankfully, in electrical engineering the rules have not changed too much; Ohm's Law is still Ohm's Law.

It is clear that the financial reporting and the data required by the engineers and the asset managers are very different. As we all know, our networks need maintaining, and as they age and deteriorate, various assets need refurbishing and replacing, all on somewhat different time scales. Most of the major items of equipment are very expensive and have long delivery times so the principle of "replace it when it breaks" is clearly not practical to electricity distribution networks where quality of service is the main driver.

The rate of deterioration (age curve) and the replacement cost are the important issues in ensuring the continuity of supply. The ideal is to replace the transformer, cable or switchboard the week before it would have failed.

Today asset management has become much more complex due to:

- Utilities growing in size
- Networks are becoming more complex
- Utilities are allegedly being merged into REDS and Metros
- Financial constraints
- Need for scenario planning
- National considerations
- Skills shortage, limited budgets

Generally asset management is not well understood by many of the stakeholders in distribution networks, and it does not increase the revenue and therefore it is not considered to be a high priority.

What most of these stakeholders fail to realise is that these are the assets that generate the existing income and the funding required. Simply to maintain the status quo is a huge challenge, as will be illustrated later in this paper.

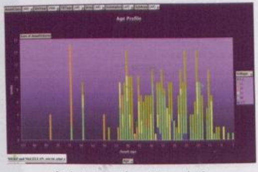
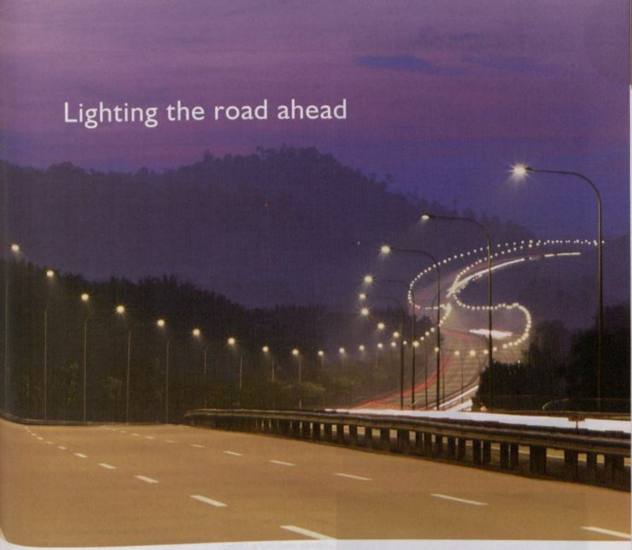


Fig. 1: A power transformer's "age analysis".

Age profile

Let us consider the deterioration of an asset. This can happen for different reasons and on various time scales, either due to high loadings, lack of maintenance, environmental conditions, fault conditions, number of faults, design, etc.,




Lamps


Luminaires


Production


Installation


Maintenance

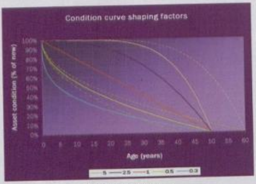


Fig. 2: Deterioration curve.

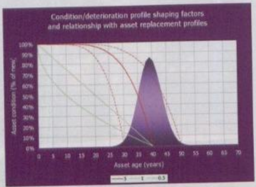


Fig. 2b: Deterioration curve and its relationship to the asset replacement profile.

Fig. 3: Three different replacement profiles.

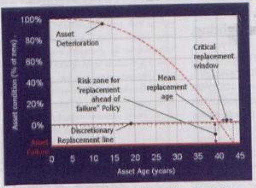


Fig. 4: The critical replacement window and the risk zone for "replacement ahead of failure" policy.

but as these conditions can be evaluated, careful system data collection can result in the generation of accurate "age profiles".

Organisations like Cigré and utilities around the globe have been collecting data for many years and such curves have been generated by international consulting companies that specialise in asset management.

One of the critical considerations is the "mean average life" of the asset. There are some utilities that do not consider that age has any great influence and the main drivers are condition and performance.

This is true of relatively young networks but it has been proved that actual age is a very valuable criterion in calculating the remaining life expectancy of assets in older networks with critical quality of supply (QOS) agreements.

As can be seen from Table 1 there is a considerable difference between the generally accepted figures in South Africa and the figures used in the United Kingdom. The figure shown in the EDI column as those recommended in the EDI "Toolkit" used for valuation purposes.

Fig. 1 shows the power transformer's "age analysis" for one of the large electricity distributors in South Africa by voltage level. The data used to compile this analysis will be used in most of the illustrations used in this paper. Here you can see that the assets range from the oldest at nearly 80 years and the youngest being an 88 kV unit installed in 2004.

Fig. 2 shows a deterioration curve in red with a deviation of ±10 years. This asset has initially a slow rate of deterioration which increases as it ages. The blue line to the left is the curve for a different asset type that initially deteriorates quickly then slows down as it ages. The straight line in blue is the standard normally used by accountants.

In Fig. 2b we have shown the deterioration curve and its relationship to the asset replacement profile. Asset managers experienced in using this type of modelling tool can combine their field knowledge of the asset class to accurately match the real conditions within the model.

It is often necessary, due to financial constraints or practical field problems, to delay the replacement of certain assets. Providing the asset is in a suitable condition this situation can be catered for within the model. The critical issues to bear in mind are that all the parameters must be included in the modelling process.

Age, condition, performance

By using a selected deterioration curve and a replacement profile for a particular asset these can be modelled and combined with the other assets of the same class and an "investment profile" can be generated for a particular asset class.

Asset class

Most models use the following asset classes in the modelling of transmission networks: transformers, switchgear, overhead lines, underground cables and protection.

Fig. 5 shows the investment profile for the asset class of transformers for a South African utility. The profile shows a present backlog of refurbishment being units still in service that have now entered the "risk zone" (Refer inset). This does not mean that the units are unsafe or that a catastrophe is waiting to happen, but is does mean that the units should be inspected, their condition verified and the appropriate action initiated.

If this type of modelling has been used in the budget preparation, funds would be available to order the replacement if required.

The financial implications of the mean asset life

In Table 1 the different "mean asset life" is compared to various conventions; the next few Figures show how these various figures impact on the refurbishment budget.

Fig. 6a shows that there is a large backlog due to the shortening of the asset life - over R180-million in refurbishment cost over 2007–2009, whereas Fig. 6b shows the same assets but using the longer asset life figures applied in the UK. The refurbishment cost is now reduced to R30-million over the same period.

This a reduction of R150-million in one asset class in one utility.

There are 187 utilities of various sizes in South Africa.

It estimated that the replacement cost of the transmission and distribution networks in South Africa is around R100-billion. If we assume this figure is correct, the refurbishment cost of the network will be R1,4-billion per annum.

In Fig. 7 the assets under the different curves can be seen clearly and from field experience it is clear that these assets do not need replacement. This data has been taken from age information for the utilities' power transformers, supplied to us, up to and including data for 2005.

Fig. 8 now shows the revised investment profile with more realistic asset life figures that result in a refurbishment budget that is now affordable. The backlog no longer exists and the refurbishment has been spread over a longer period.

Some might argue that this is a distortion of the facts, but if you have assets presently on your system, in good condition and providing the performance required, why replace?

As can be seen, refurbishment of the network is critical to the sustainability of the network, quality and security of supply, and that this is a necessary cost. To put this cost in perspective, we have compared the amount spent in South Africa to the amount spent by Australian distributors operating similar networks.

Fig. 9 shows the current refurbishment investment of ten South African distributors, the backlog being the number of assets that have reached or passed their mean average life date. It also shows the expected investment based on the asset profile data supplied by the various distributors. The near future is not so bad but the "Tsunami" is just over the horizon.

Column 1 is the current investment; column 2 is the backlog; column 3 is the 1-5 year projection; column 4 the 5-10 year projection; column 5 the 11–15 year projection; column 6 is the 30 year projected investment.

As can be seen in Fig. 10, out of the ten South African distributors, two are over-investing, two meet the national average and six under-spend considerably. If we remove the two over-spending distributors, the South African average will drop significantly. The important issue is then, the difference in the relative spend of South Africa and Australia.

As can be seen in Fig. 11, the percentage of refurbishment spent by some of the major distributors/metro's/municipalities is well below the accepted international norm.

The role of the asset manager

Data management

One of the most difficult situations we have been faced with is our data, its format, reliability and storage. As City Power has been formed from a number of autonomous municipalities, the data was in different formats and the conversion to a single format was always a task that was deemed to be non-critical, hence it was never done. Furthermore the emphasis in new projects has been the speed of delivery of the service rather than data formatting.

Now we are faced with the huge task of collating all the data from the various sources, transferring it into a common format that all departments can utilise without having to build their own databases in order to store the information needed within their own department.

It has become obvious to City Power that it has the information somewhere within the organisation but no-one knows where. A huge amount of resources have been wasted researching, gathering and storing information that is duplicated elsewhere.

Hence the organisation has now revised to ensure that the emphasis is given to the importance of IS (information systems) and a senior person is dedicated to the management of all the data and asset management.

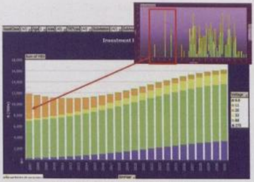


Fig. 5: Investment profile for transformers.

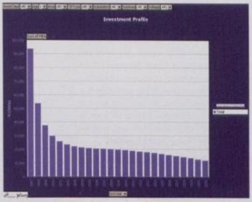


Fig. 6a: A backlog due to shortening of asset life.

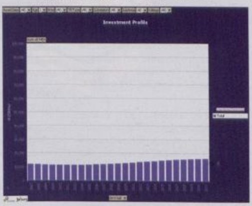


Fig. 6b: UK application.

Condition assessment

There are a number of schools of thought on the assessment of the "life" of an asset. Some base the life on the manufacturer's recommendations.

As can be seen from the earlier part of this paper, experience has shown that this is in most cases too short a period. Then there are those who rely on the service conditions and de-rate the life depending on the stress that the asset is deemed to cope with while in actual service, and there are others that measure the performance.

In truth, the real answer is a combination of:

- The age of the asset
- The condition of the asset
- The service conditions
- The performance of the asset

In the past decisions were based on one

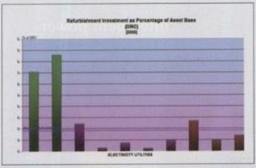


Fig. 10: Over-investments.

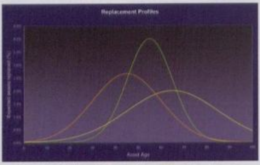


Fig. 11: Refurbishment investment as percentage of asset base..

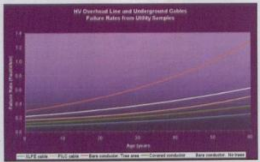


Fig. 12: The outputs that we will generate.

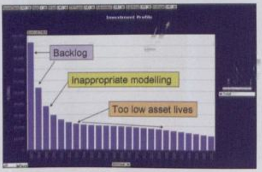


Fig. 13: Investment profile.

management that our financial requirements are vital to the maintenance of the network.

Since the installation of the software, we are able to identify our immediate requirements, the critical areas in the near future and then produce scenarios within minutes, each showing the results by individual asset in the case of transmission asset and by circuit in the case of the distribution network.

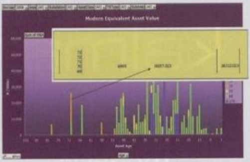


Fig. 14: Five- year plan and medium term forecasting.

In Fig. 12 the graph shows the age analysis of our transmission transformers. If the asset manager wants to know which individual assets form a particular bar he/she can simply click on the bar and the value of these units are displayed; a further click on that data and the details of the individual assets are displayed. In this instance these are 20 kV transformers and will not be replaced 'like for like'. The asset register will reflect that nformation and that the project is budgeted separately.

The asset manager can then remove these units from the scenario and that expenditure will then automatically be allocated to the replacement of the next group of assets due for replacement. These scenarios are generated in seconds so a number of propositions, together with their individual motivations can be assembled, presented and discussed, quickly and efficiently, making the budget process much shorter.

As can be seen from Fig. 14, medium term forecasting is far more realistic, giving us more credibility with management, resulting in increased support and enhancing the efficiency of the company.

The role of the asset manager

As can be seen from the above a great deal of information can be generated by this type of modeling and the interpretation and analysis is crucial to the effectiveness of the decisions we make.

We consider this position to be key to the successful maintenance of our network ensuring we provide the expected quality of service hence we have appointed a senior engineer to manage the assets within the network. His knowledge of the software is important but his knowledge of the network and performance of the individual assets is where the ultimate success lies.

Conclusion

In conclusion it can be seen that the "mean average age" of the asset is critical to the refurbishment budget. Furthermore the condition of the asset is crucial in the modelling of network assets. The management of network assets is essential and complex, but there are appropriate manager-friendly tools to assist us. Central control of the process, the data management, the analysis and reporting should be the responsibility of experienced asset managers.

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[2] Cliff Jones – Sinclair Knight Merz (Brisbane, Australia).

[3] Figures from the model developed by Dr. Floren Castro Sayas, Consultant

[4] Sinclair Knight Merz (Newcastle), UK. Δ

Predictive maintenance using thermography

by Brendan Campbell, Comtest

Temperature is a key condition indicator which is the most frequently made measurement as the temperature measurement indicates the state of "health" of machinery and the human body. By periodically measuring these temperature indications we are able to set up a thermal profile which in turn allows us to predict an impending failure before it happens and prevents the cost of downtime.

This paper will look at some of the older techniques of maintenance and the benefits of predictive maintenance using thermography in industrial environments and the effect on revenue protection.

Maintenance costs are normally a major portion of the total operating cost in most industries. A major factor to these high costs was the misuse of the expenditure due to lack of factual information that quantifies when and what kind of maintenance is required to either repair or replace critical machinery or equipment.

Typically the equipment was not monitored to gain knowledge of performance, failure history and any other symptoms that would lead to premature failure. In many cases the maintenance staff would get the blame for a poor installation and the cost of replacement or repair would be greater than the maintenance budget.

The general feeling has been that maintenance is a necessary evil and that nothing could be done to improve maintenance costs. The most common maintenance programs employed in the past were: run to failure management and preventive maintenance.

Run to failure management

This program was simple, the equipment fails, you fix it and it would seem to be the most cost effective method as no money was spent on maintenance; this however would have the greatest effect on the bottom-line as the following expenses would be incurred:

- Downtime
- Low production
- Poor quality

This reactive maintenance has further disadvantages such as the requirement of carrying spare equipment and a high inventory of spares, the expense incurred on this form of maintenance can be three times more than a scheduled or preventive repair.

Preventive maintenance

This form of maintenance is time driven and relies on historical data of equipment as it involves statistical data and hours of operation.

In most cases preventive maintenance uses the MTTF statistic and an illustration of this is represented in Fig. 1.

Indicates that a new machine has a high probability of failure during the first few hours or weeks of operation due to installation or manufacturing problems. Following the initial period the probability of failure is relatively low for an extended period of time.

Following this normal machine life period, the probability of failure increases sharply with elapsed time or hours of operation.

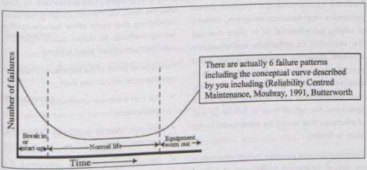

Fig.1. Bathtub curve

This raises further factors on the quality of maintenance as all preventive maintenance programs assume that machines will degrade within the statistical time frame typical for its particular classification.

For example a piece of equipment will normally run 18 months before it should be replaced. Using preventive management techniques, the equipment would be removed from service and rebuilt after 17 months of operation.

What if this equipment failed before the 17 month period? We would resort to run to failure techniques and we have seen how this form of maintenance impacts on the bottom-line.

Preventive maintenance is very costly as in some instances it is very similar to run to failure maintenance and from this form of maintenance the information is not always factual.

If only we had a crystal ball, that could tell us if something was about to fail.

Thermography

Thermography is a non-contact technology that measures infra red wavelengths to determine an object's thermal radiation distribution at a safe distance and in real time. In other words we are measuring the thermal representation of an object as well as thousands of temperature points in real time.

The electromagnetic spectrum

The electromagnetic radiation spectrum is the complete range of the wavelengths of electromagnetic radiation, beginning with the longest radio waves (including those in the audio range) and extending through visible light (a very small part of the spectrum) all the way to the extremely short gamma rays that are a product of radioactive atoms.

The entire range of radiation extending in frequency from approximately 1023 Hz to 0 Hz or, in corresponding wavelengths, from 10-13 cm to infinity and including, in order of decreasing frequency, cosmic-ray photons, gamma rays, x-rays, ultraviolet radiation, visible light, infrared radiation, microwaves, and radio waves.

Most thermal imagers use the 8 - 14 micron range due to higher sensitivity to ambient temperature, reduction in reflected sunlight and good transmittance.

With a thermal imager it is quick, easy and safe to check critical parts while the machine continues to run. An effective predictive maintenance program can add to your bottom line by using thermal imaging technology to proactively find problems before they cause an outage, so you can effectively plan a shut down for repair or equipment replacement.

This takes a lot of the guess work out and now you are able to predict these failures with factual information.

Electrical application

Thermal imagers are an easy way to identify apparent temperature differences in industrial three phase electrical circuits compared to their normal operating conditions. By inspecting the thermal gradient of all three phases side by side you can quickly spot performance anomalies on individual phases, these temperature differences are an indication of a power quality problem that may be due to unbalance, overloading, harmonics or even open circuits.

New electrical components begin to deteriorate as soon as we install them. Vibration, fatigue, environment and age cause the loosening of electrical connections whenever a load is put on a circuit.

Put it this way, all electrical connections over time will fail, fortunately a loose or corroded connection increases resistance at the connection and the increased resistance results in an increase of heat which in turn has a higher consumption of energy and adds to the cost of electricity.

When using thermal imaging to troubleshoot loose, over-tight or corroded connections in electrical systems, first remove the panel covers and then:

- Remember safety steps
- Compare temperatures of connections within panels
- Look for connections that are hotter than others

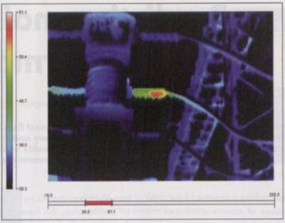

Fig. 2: Thermal image

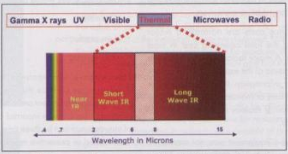

Fig. 3: Electromagnetic spectrum [Snell Infrared training manual level 1]

- Look for hot spot related connections as these normally appear warmest at the spot of high resistance and cooler the further you get from the spot
- Store the relevant image for further analysis

Other thermal imager applications include:

- Mechanical
- Process
- Building
- Medical

Predictive maintenance

Predictive maintenance is a condition driven preventive maintenance program, instead of relying on industrial or in plant average life statistics to schedule maintenance activities, predictive maintenance uses direct condition monitoring techniques which determine operating condition, efficiency, heat distribution and other indicators to determine the actual time to failure or loss of efficiency that would be detrimental to the plant or facility.

This program now provides factual information on actual operating conditions of critical assets, including efficiency, as well as the actual mechanical condition.

Now maintenance management has the factual information to effectively plan and schedule maintenance activities.

Predictive maintenance is not vibration testing or thermal imaging, it is a philosophy or attitude that simply stated uses actual operating conditions of plant equipment and systems to optimise total plant operation.

Predictive maintenance is an integrated approach to condition monitoring and includes thermography and vibration analysis.

A comprehensive predictive maintenance program utilises a combination of cost effective tools, i.e. thermal imaging, vibration monitoring and some other non-destructive testing methods, to obtain actual operating conditions of critical plant systems.

If we look at some of the benefits of predictive maintenance we can see that:

- We can minimise unscheduled breaks in production.
- We can identify problems before they become critical.
- Major repairs can be prevented if a problem is detected early.

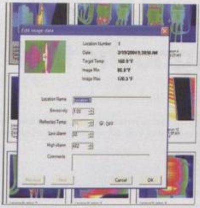

Fig. 4: Inside IR software.

- Repaired equipment is in acceptable condition.
- It could eliminate 33% to 50% of maintenance expenditure.
- It improves the life span of critical equipment.

Maintenance routing

Maintenance routing requires frequent inspections of equipment and this could be visual inspections or non-destructive tests using various test instruments.

The frequency and sequence of inspections should be predicated on the unique requirements of each system and will vary depending on the make up of facility equipment.

There are three primary criteria that should be considered when developing routes for predictive maintenance:

- Travel time
- Logical sequence of inspection
- Safety
- Criticality of machine

The best solution is to create a regular inspection route that includes all key electrical panels and other load connections such as drives and controls. This gives you a baseline to compare to which will help you to determine whether a hotspot is unusual or not, and it is also helpful for verifying if repairs were successful.

You could then analyse stored images taken of your equipment and then return at regular maintenance intervals to reshoot your equipment. Then using a computer compare the new images with the previous ones to determine any gradual changes in temperature that could signal impending problems.

This allows you to plan a maintenance route that can be uploaded to your imager, which gives you a description, the image and date of the image. As seen in Fig. 4.

Conclusion

A properly conducted predictive maintenance route will ensure longer life cycles of equipment, decrease downtime and increase profitability of production.

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Sweep frequency response analysis as a diagnostic tool

by Luwendran Moodley, eThekwini Electricity; and Brian de Klerk, eThekwini Electricity

This paper details the use of sweep frequency response as a diagnostic tool to detect winding deformation and core displacement in power transformers. Practical case studies are presented that demonstrate the effectiveness of this technique.

Sweep frequency response analysis has proven itself within eThekwini Electricity to be a valuable diagnostic tool for the detection of winding movement and other faults that affect the transformers impedance.

The loss of mechanical integrity in the form of winding deformation and core displacement in power transformers can be attributed to the large electromechanical forces due to fault currents, winding shrinkage causing the release of the clamping pressure and during transformer transportation and relocation. Winding deformation and core displacement, if not detected early, will typically manifest into a dielectric or thermal fault. This type of fault is irreversible, with the only remedy being rewinding of the phase or a complete replacement of the transformer. It is therefore imperative to check the mechanical integrity of aging transformers periodically, and particularly after a short circuit event to provide early warning of impending failure. Hence an early warning detection technique for such phenomena is essential. Frequency response analysis is recognised, as being the most sensitive diagnostic tool to detect even minor winding movement and core displacement.

Background of frequency response analysis

Frequency Response Analysis has been developed over the years since its introduction in its 1960s. It initially used the impulse measurement technique and software was used to transform results from the time domain to frequency domain. In the 1970s Ontario Hydro pioneered frequency response by injecting a sinusoidal signal and measured the frequency response directly. In the 1980s National Grid Company (UK) refined the technique by first using the impulse method but soon the sweep method was employed as it was found to be better suited for site work and gave better high frequency results. The 1990s saw the introduction of the first commercially built systems to be used on site. Presently there are a number of worldwide users that use the sweep and impulse method.

Assessment of mechanical integrity

The traditional methods of electrical tests carried out on transformers such as winding capacitance, excitation current and leakage reactance measurements have proven to not be particularly sensitive to detect winding movement. Each of these methods has drawbacks.

Winding capacitance measurements can detect winding movement successfully only if reference data is available or if measurements can be made on each phase. In almost all older transformers, reference data is unavailable and on site per phase measurements are not possible.

The excitation current method is an excellent means of detecting turn-to-turn failure as a result of winding movement. However, if a turn-to-turn failure is absent, winding movement can remain undetected.

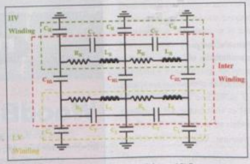

Fig. 1: Simplified equivalent circuit with lumped RLC components.

Per phase leakage reactance measurements generally show little or no correlation between the phases. The three phase equivalent measurement is a broad test and can mask a variance in one of the phases. Further, the discrepancies from the nameplate value of 0,5 to 3% can be a reason for concern. This makes accurate assessments of the mechanical integrity of the transformer very difficult.

Other condition monitoring tools such as dissolved gas analysis (DGA) do not aid in the detection of winding deformation and core displacement.

Fundamentals of frequency response analysis

The transformer is considered to be a complex network of RLC components. The contributions to this complex mesh of RLC circuit are from the resistance of the copper winding; inductance of winding coils and capacitance from the insulation layers between coils, between winding, between winding and core, between core and tank, between tank and winding, etc. However, a simplified equivalent circuit with lumped RLC components as illustrated in Fig. 1 can be used to accurately explain the principle of frequency response.

Any form of physical damage to the transformer results in the changes of this RLC network. These changes are what we are looking for and employ frequency response to highlight these small changes in the RLC network within the transformer. Frequency response is performed by applying a low voltage signal of varying frequencies to the transformer windings and measuring both the input and output signals. The ratio of these two signals gives the required response. This ratio is called the transfer function of the transformer from which both the magnitude and phase can be obtained. For different frequencies the RLC network offers different impedance paths. Hence, the transfer function at each frequency is a measure of the effective impedance of the RLC network of the transformer. Any geometrical deformation changes the RLC network, which

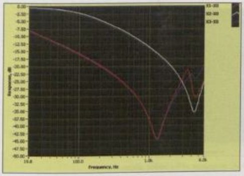

Fig. 3(A): Response of the LV winding.

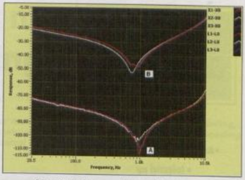

Fig. 4(A): Multiple grounded neutral B - after repair.

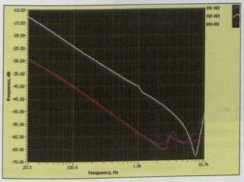

Fig. 3(B): Response of the HV winding.

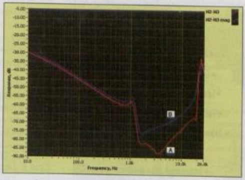

Fig. 5(A): Fingerprint response (B): magnetised core.

windings are only performed on transformers that are suspected of having movement at high frequencies. This test method merely acts as an indication and does not identify the area of concern.

Ensuring reliable measurements

SFRA like most test equipment requires correct and electrically sound connection to the transformer. Measurements must be made confidently and conscientiously to ensure reliable and meaningful measurements. In order to ensure meaningful measurements, eThekwini Electricity has put into place a simple procedure that is followed for each test. Below are a few key points that must be followed to ensure meaningful measurements:

- The transformer being tested must be completely disconnected from the network
- Neutral must be removed to ensure that the transformer under test is floating
- The transformer and tapchanger must be filled with oil
- All nameplate data must be accurately captured
- Check nameplate to ensure correct connections are made
- If DC testing was performed the core must be demagnetised before any SFRA measurements
- Prior to any measurements the leads must be tested
- Solid electrical connections must be made for the signal, measurement and earth lead.
- Measurements must be made at the lowest, nominal and highest tap position and the tapchanger movement must be from the lowest to highest. One additional measurement must be made on the tap position in which the fault occurred.

Case studies

These case studies illustrate real problems found with transformers in eThekwini Electricity's network.

Case 1: Shorted turn failure

These are the responses of the HV and LV winding of the same transformer. There is clearly a significant difference in the White phase when compared to the other two phases. This is a result of a shorted turn failure. A shorted turn has the effect of creating an imbalance in the reluctance on one of the core limbs (in this case the white trace), which produces this characteristic change in the low frequency response. Excitation current and ratio test supported this diagnosis.

Case 2: Multiple grounded neutral

Fig. 4(A) shows the LV winding response of a multiple grounded neutral and Fig. 4(B) shows the response after the transformer was repaired. The comparison of the two responses shows a significant difference in the starting dB values. This difference in the dB or vertical shift in response A is attributed to the change in the resistance of the transformer under test.

Case 3: Core magnetisation

Fig. 5(A) shows the fingerprint response of the transformer and Fig. 5(B) shows the response as a result of a magnetised core. This transformer was taken out of service as a result of a tapchanger failure. The tapchanger was repaired and replaced. As a standard a micro-ohm test (DC test) was performed on the tapchanger contacts before returning the transformer to service. This DC test inadvertently magnetized the transformer core.

The response of Fig. 5(B) shows a shift and the elimination of existing resonance frequencies. The transformer core was demagnetised and the new response matched that of the fingerprint. This magnetised core situation was also identified by the excitation current test, which showed a significant increase in current from the fingerprint test.

in turn changes the transfer function at different frequencies and hence highlights the area of concern.

Interpretation of responses

Measured responses are analysed for any one of the following key indicators:

- Starting dB values (typically -30 to -50 dB for HV winding and -5 to -15 dB for the LV winding)
- The expected shape of a star and delta configuration with attention to the core resonant point/s.
- Comparison of response to fingerprint
- Comparison of response to the different phase of the same transformer
- Comparison of response from sister transformer
- Creation of new resonance frequencies and the elimination of existing resonance frequencies.

A guideline for the use of the sweep method developed by Doble has been in existence for many years and has proven to be very useful in identifying the area of concern. These different frequency bands have different sensitivities to different mechanical failure modes.

Impedance at different frequencies relates to the resistance, capacitance and inductance of a transformer. The resistance is related to the physical construction of the winding (shorted turns, core earth etc.) and results in the vertical shift (dB axis) of the response. The capacitance and inductance are related to the geometry of the winding (deformation) and results in a horizontal shift or frequency shift. Fig. 2, shows the responses of a 132/11 kV, 30 MVA, Yd, core formed, 3 phase, 3 limb transformer.

At the lower frequency range the capacitance of the transformer can be disregarded and the response is purely inductive. At these frequencies the inductance of the magnetic circuit dominates. There is a significant difference in the responses between the outer two phases and the center phase at this frequency range. This is due to the flux paths of the core. The center phase has two flux paths of equal reluctance and the outer phase has two flux paths of different reluctance. As a result the outer phases have two resonance points as compared to the center phase that has just one resonance point. This also accounts for the difference in the starting dB values.

At higher frequency ranges the response looks very confusing and complex as a result of the numerous resonance points. At this frequency range the winding inductance dominates with

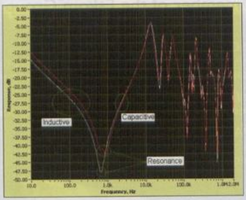

Fig. 2: Frequency response of a sound transformer.

the magnetic circuit effectively screened. Hence, the winding responses are less dependent on the magnetic circuit, which makes the measurement more sensitive to winding deformation. At the highest frequencies, the inductance can be disregarded and the response is effectively capacitive.

eThekwini Electricity's experience

eThekwini Electricity is responsible for the maintenance of over 250 transformers operating at primary voltages between 275, 132 and 33 kV with ratings from 315 to 15 MVA. The average age of these transformers is 25 years. Notwithstanding their age, these transformers have proven to be very reliable. Life assessment of these transformers takes into account oil analysis (oil screen and DGA), electrical and mechanical condition of the transformer. The availability of these test results, allows asset managers to make informed decisions on the following actions:

- Replacement of the transformer before end of life
- Refurbishment of the transformer
- Carry out corrective maintenance
- Postponement of maintenance
- Loading of the transformer

For the above reasons, eThekwini Electricity has placed great emphasis on obtaining and understanding the condition of all transformers in the network, through the introduction of advanced diagnostic tools.

eThekwini Electricity's approach to condition assessment on transformers is as follows:

- Monthly visual inspection
- Oil analysis in the form of Oil screen, DGA, Furan analysis, tan delta of oil at 90°C
- Electrical tests in the form of tan delta and capacitance measurements on windings and bushings, 10 kV ratio measurements, excitation current measurements, leakage reactance measurements, sweep frequency response analysis (SFRA), insulation resistance measurements
- Infrared scanning
- Calculation of percentage moisture by dry weight and percentage saturation of oil.

Sweep frequency response analysis (SFRA)

Due to the lack of sensitivity of the existing test to detect winding movement and the positive response from international users, eThekwini Electricity introduced the SFRA (Doble M5100) as a diagnostic tool three years ago. Since its inception, the SFRA has proven to be a powerful tool for reliable and sensitive means of detecting winding movement and other faults that affect the impedance of the transformer.

As a standard, eThekwini Electricity performs SFRA measurements under the following conditions:

- On all new transformers for fingerprinting purposes
- As part of routine electrical tests
- After relocation
- After long duration short circuits
- After repairs to tapchanger
- After any vacuum treatment, purification and regeneration
- After any type of fault
- After any type of maintenance

SFRA measurements are done as a standard on the highest, lowest and nominal tap positions. An additional measurement is made on the faulted tap position after any type of fault has occurred.

Short circuit tests on both the HV and LV

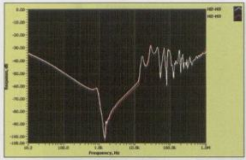

Fig. 6(A): Responses of the middle phase.

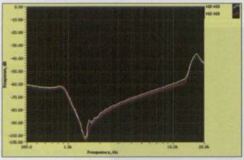

Fig. 6(B): Zoom-in of the above response.

Case 4: Extra core earth

Fig. 6(A) and (B) shows the response of the middle phase with (White trace) and without (Red trace) the extra core earth. Differences were noted on all three phases but the greatest difference was noted on the middle phase. Fig. 6(B) shows a difference in the capacitance response from about 1,5 kHz to 14 kHz. Further, the white trace has a resonance frequency at 1,6 kHz which is absent in the Red trace. This creation of a new resonance frequency is clearly a cause of concern.

Conclusion

Sweep frequency response analysis has proven itself within eThekwini Electricity to be a valuable diagnostic tool for the detection of winding movement and other faults that affect the transformers impedance. An advantage is that reference responses are not required to make an accurate decision as a comparison of response to the different phase of the same transformer and a comparison of response from the sister transformer are used successfully to diagnose the mechanical integrity of the transformer.

The results obtained are reliable, repeatable and unaffected by test lead position, weather and electromagnetic interference. The test is easy to perform and operate, however measurements must be made confidently and conscientiously to ensure reliable and meaningful diagnosis. By focusing on its ability to detect winding movement we under emphasise the fact that measured responses are capable of providing an indication when no winding movement has occurred. This ensures that a transformer is returned to service quickly and avoids a costly internal inspection.

SFRA when used in conjunction with other diagnostic tools can provide a complete condition assessment of the transformer and in so doing ensure that informed decisions are made by asset managers.

Acknowledgements

The authors would like to express their gratitude to Tony Dold and Howard Whitehead for their approval of the SFRA program and ongoing support.

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Transformer asset management using monitoring control

by SL Braver and P Stewart, Dynamic Ratings, Australia; and T Pink, Dynamic Ratings, USA

The paper explores the benefits of the current state of transformer management systems and condition monitoring, the ability for utilities to extend the life of their transformer assets while obtaining the added value of higher loading capacities through real time monitoring control and communications.

Electrical utilities in general have experienced radical changes over the past few years. Cost and competitiveness have become common business drivers and tight business management is now the norm. Overcapacity is a thing of the past, it is a luxury that can no longer be afforded. Assets must be driven harder to keep costs low, yet without loss of customer service and reliability. Quality of supply measurements quickly show up poor performance. At the same time, networks have become more difficult to operate as they approach their capacity limits and redundancy options dwindle. In order for a utility to operate successfully in this environment, better tools are needed to permit efficient network management.

TMS (transformer management systems) and uprating safely

Power transformers represent one of the key components in most utility networks. They are the single most costly items in a substation and can become strategic bottlenecks in a power network system. Significant opportunities for improvement in transformer management as a network component have become possible. This is through new technology that has been developed specifically to address the issues utilities currently face. This paper compares traditional transformer operating practice (which can be equated to "flying blind") with the approach taken and features available when an effective TMS (transformer management system) is employed. Particular emphasis is placed on operating above nameplate and how it is achieved through dynamic rating without compromising safety on either new or existing transformers.

Reasons for investing in dynamic rating

Dynamic rating is touted as a transformer management feature of value. Let us examine why.

As stated by Russell [1], "As asset utilisation is increased, the spare capacity once available in the system becomes increasingly scarce. The day-to-day operation of the power system becomes more and more difficult. If the network is going to be run closer to an overload state without damage, we need a better system of monitoring, predicting and acting to prevent damage. It is important that support and decision tools are available to the system operators to ensure effective and efficient management of the power system is achieved and to take automatic action if an operator does not react quickly enough to prevent possible damage.

"Traditionally, the rating that operators use to run the power transformers has been prepared well in advance and is based on worse case assumptions. Factors such as wind speed and direction, solar radiation, ambient temperature, pre-load can all affect the real-time rating of plant commonly utilised in the electricity industry. For practical reasons, it is necessary to make a number of engineered assumptions about these factors based on the utility's operating policies when determining the rating of plant. We should also recognise that for any given event when the transformer is running close to its pre-determined rating, the environmental or other conditions may not approximate the assumptions that we have made for these factors very well or at all. In most cases, the utility does not expect the system operators to re-evaluate the ratings on the fly during the system emergency i.e. the system operator should operate the plant within the rating prepared without compensating for current conditions. Therefore, by necessity, for most actual conditions the pre-determined thermal ratings are generally conservative to ensure the transformer is operated safely. This approach invariably yielded very conservative rating figures because of the need to make worst case assumptions. A significant increase in ratings can be assigned, if the actual operating conditions are used to continuously calculate an accurate thermal model for the plant.

"What is needed is a cost-effective technique for maximising the asset utilisation of transformers through real-time monitoring and control while ensuring the transformer is operated within its design parameters. By leveraging the information available through the real-time control and monitoring system, the transformer can be operated to its maximum safe load and its life can be maximised."

Another economic gain to be made through the implementation of dynamic ratings is reduction of the following; losses, costs of spinning reserve, running less efficient plant to bypass percieved bottlenecks in the system. Funnel has reported savings by NGC of over $600-million per annum largely through the application of dynamic ratings that allowed more efficient operation of the system.

Management of the power network based on 'fact', rather than assumption, has become increasingly important as electricity utilities worldwide are faced with ever increasing commercial demands and constraints. Energy utilities must maximise shareholder value through continual improvement and innovation. The techniques described here can have significant impact on the utility's bottom line."

In order to understand how dynamic rating works we firstly need to review standard transformer rating.

Transformer rating

The rating of a transformer (or maximum allowed loading) is governed by thermal considerations and is based on a simple model. Energizing a transformer results in losses in the core and windings which become hot, causing the oil temperature to rise. Increased loading increases the losses and hence the temperature. The highest temperature in the winding must not exceed the allowable design limit. It is not possible to measure this hot spot temperature directly, so the top oil temperature is measured instead and various methods have been employed to simulate or estimate the WHS (winding hot spot) temperature, with varying degrees of success. See Appendix for more information on these as well as fibre-optic direct WHS measurement systems.

Since factors such as ambient temperature, wind speed and direction, etc. also influence the WHS temperature, the transformer rating is based upon defined values for these factors. Loading guides define limits to loading based on various criteria related to the relevant factors. However, it should be stated that the figures are for transformers in good ("as new") condition and generally assume a worst case environmental situation.

Under transient conditions the rate of rise of oil and winding temperatures depends on the difference between rate of energy generation and dissipation and on the thermal time constant of the transformer and its components. It therefore becomes more difficult to simulate or estimate the WHS temperature when load and environmental conditions are changing.

Static rating

Transformer condition has a bearing on loadability. In an aged transformer for example, if the solid insulation moisture content is high, bubbling could commence at temperatures well below the design limits. Thus the actual transformer condition must be assessed and taken into account before setting realistic limits to loading for that transformer.

Traditionally the loading guides have been used to prepare static thermal ratings for transformers for various ambient and operating conditions. Some SCADA and substation control systems include transformer thermal models with continuously monitored load currents, and sometimes, ambient temperatures.

Typically this static thermal rating makes it possible to load a transformer 10 to 20% above nameplate rating for extended periods without risk of damage, but this is still not dynamic rating.

Dynamic rating

The dynamic rating of a transformer is the maximum load possible without exceeding predefined thermal and current rating limits, based on real time measured ambient and transformer temperatures, condition, cooling status and load. In addition to real-time measurements and calculations for dynamic rating, advanced transformer management systems employ enhanced thermal models which are intrinsically more accurate. A transformer may typically be loaded a further 10 - 20% higher (above static rating) and with greater confidence with such dynamic rating than with static thermal rating. Instead of "flying blind" when operating close to the limits, dynamic rating provides timely and accurate information as to what the real thermal limit is at any point in time.

The "what-if" dynamic rating information can be presented in two ways [2]:

- *Max load:* Given the present (or pre-defined) conditions such as ambient temperature, transformer temperature, load and LTC position, what is the maximum load that can be carried for a specified time without exceeding the preset load and/or thermal limits?
- *Max time:* Given the present (or pre-defined) conditions as the starting point, how long can the transformer carry the present (or pre-defined) load without exceeding the preset load and/or thermal limits?

Taking advantage of dynamic rating can result in very large savings due to deferred capital expenditure and reduced number of outages.

A 1998 survey, conducted with a representative sample of US utilities for a prior Doble paper, revealed that approximately 30% of utility customers were moving toward some form of increased or dynamic loading policy [3] "A more recent survey of 63 member utilities of the Edison Electric Institute (EEI), regarding transformer loading practices, revealed that over 75% allowed regular short-term overloading of their transformers. The survey also confirmed that many utilities use dynamic loading methods that accelerate a transformer's aging process in order to obtain additional output during contingency conditions" [4].

Since the uprating is achieved without exceeding predefined thermal and current rating limits it is not only completely safe, but the very fact that such intimate knowledge of winding temperature and condition is continuously available in real time leads directly to several other advantages. Some of the more significant are increased reliability and reduced risk of unplanned outages; opportunity for reduced maintenance costs by implementing condition-based maintenance and life consumption tracking.

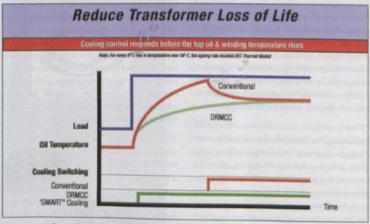

Fig. 1. Cooling control responds before the top oil and winding temperature rise

But these are only some of many benefits of an effective transformer management system.

Monitoring

Depending on the system employed and the features implemented, the operational data to be monitored may include: single or three phase amps and volts, watts and vars; frequency; tap position; ambient, oil and winding hot-spot temperatures; tap changer status and cooler status. As a minimum, to implement dynamic ratings, one needs to monitor load current, ambient air temperature in the vicinity of the transformer coolers and transformer top oil temperature. Further improvement in accuracy may be obtained by monitoring tap position since this affects losses and temperature rise.

Where available, additional support for operational decisions is obtained using fibre optic probes to directly measure temperature spots, although this is only possible on new windings since the probes must be fitted during manufacture.

Improved accuracy of temperature measurements on existing transformers can be achieved using electrical sensors compared to traditional capillary tube instruments. With the modern TMS systems this feature is available. This is important because the ageing rate of cellulose insulation increases rapidly with temperature. Oil and winding temperatures can be both measured and calculated (from ambient temperature and load), enabling the thermal model parameters to be calibrated to great accuracy.

Transformer condition assessment parameters are also monitored and can be integrated into the TMS system. These could include any combination of the following:

- Moisture in oil
- Dissolved gas in oil
- Bushing gamma or tan delta
- Partial discharge
- WHS direct temperature measurement
- Oil dielectric withstand

The particular parameters measured depend upon the criticality of the transformer. The existing transformer service history may also have an influence. The recommended philosophy is to monitor just sufficient diagnostic information continuously on-line to give a reliable early warning of potential problems. This can then

trigger more thorough diagnostics and site testing as required. This approach leads to savings in monitoring equipment and maintenance costs, improved reliability and reduced down time.

The TMS can also keep track of fan and pump run hours, transformer ageing rates and accumulated age (life consumption) and the number of tap changes for each tap position. Event recording and data logging facilities are also usually included to facilitate incident analysis and fault investigations.

Cooler control

Typically in a conventional TMS the cooling fans and pumps are turned on and off automatically at the respective temperature set points of the top oil and winding hot spot. They may be manually or automatically controlled.

An advanced TMS should have a "smart cooling" feature, that on sensing a sudden increase of the load it predicts what the ultimate winding temperature is going to be, and would start the cooling fans and pumps immediately to cool the transformer without having to wait for the temperature to reach the set point. The TMS predicts (based on present temperatures, tap position and load) where the top oil and winding temperatures are headed. If a higher than normal temperature is predicted the cooling is turned on immediately. Thus, the insulation will not be exposed to the high temperature and unnecessary ageing that it may have otherwise experienced.

For some transformers the fans and pumps may not need to run for long periods because of light loads and low ambient temperature. It is vital that when they are required to run, they will run. The fans and pumps can be programmed by the TMS to "exercise" them periodically to detect any faulty equipment. In the event of failure of a temperature transducer or its own communications or power fails, cooling is switched on ("Fail Safe").

The TMS should also be able to determine when a sensor fails and provide an alarm when such an event occurs and again switch to a fail-safe mode of operation.

Voltage & OLTC control

The TMS should be able to control and monitor the secondary voltage and OLTC. Following are the optional voltage control configurations and modes of operation:

- Independent manual
- Independent auto
- Master manual
- Master auto
- Follower
- Reverse reactance
- Vars sharing
- Circulating current
- SCADA control (direct commands or changes in setpoints or tolerances)

Alarms can be generated if the control voltage is outside tolerance for too long, or if a tap change fails to complete once initiated. Control of two- and three-winding transformers, separately and auto wound is also possible.

The TMS can also monitor and track frequency of use and wear factors of individual tap positions so that maintenance scheduling can be optimised.

Communications

Instead of a multiplicity of devices, the transformer management system serves as a single point of communication with the outside world, thereby greatly simplifying communications and facilitating access to information about all aspects of the transformer operation and status. All this information is available in real time and is of value to many different groups in the utility through a common web server type interface.

There are 4 primary hardware communication connections that are most common: SCADA, modem, LAN/WAN and Internet.

The TMS system collects a wide variety of information including real time operational information, condition status, maintenance indications and asset life consumption. Each piece of information may be important to one or more groups within the utility. When specifying a TMS system, it is very important to consider how that system can benefit all areas within the utility.

Savings

Dynamic rating enables controlled emergency loading beyond nameplate rating and beyond what is possible with conventional static thermal rating based on the loading guides, without undue risk.

When sufficient continuous on-line monitoring is installed to provide early warning of most types of potential problems and faults, further large savings can be achieved by reducing the risk of failure and improving reliability and reducing maintenance costs by using condition-based rather than time based maintenance.

Improved control and communication capabilities facilitate the trend to unmanned substations and reduced frequency for operators and maintenance personnel visits to substations.

The added cost of putting a TMS system on a transformer is typically 2 - 5% of the total transformer cost. Power transformer users stand to harvest many benefits from the added information and improved control. The relatively small cost can improve the reliability and can facilitate safe higher loading capacity.

Simulated winding hot spot (traditional WHS gauge)

Knowledge of Winding Hot Spot (WHS) temperatures provides critical information regarding safe transformer loading levels. There are three main methods of identifying the winding hot spot of a transformer:

- Simulated WHS temperature (gauge)
- Calculation (electronic temperature monitoring)
- Direct measurement (fiber optic sensors)

Conventional winding temperature indicators use a capillary thermometer to measure top oil temperature, and have a small heater in them to simulate the temperature rise of the winding hot spot over the top oil temperature ("the gradient"). Current from one of the bushing CTs is passed through the heater, raising the measured temperature. The wattage output of the heater is calibrated using a resistor or other calibrating device.

The capillary thermometer provides a typical accuracy of +/-2 to 3°C at the one point of calibration and is known to deteriorate with time. Errors of 5 to 10°C on site are not uncommon. To remain accurate, the system requires regular calibration and servicing, this is difficult to do on site.

Calibration of the WHS heater is based on the temperature rise tests, which measure the average winding and oil temperature rise. The difference is the average gradient, to which is added an allowance for additional rise of hot spot over average in accordance with the IEEE or IEC standards.

The time constant of the simulated value is determined by the sensor, thermal well design and based on the amount of oil circulation near the thermal well (which will dissipate the heat generated by the resistor). The resulting time constant cannot be tuned or adjusted.

Transformer manufacturers are responsible for calibrating the heater to read correctly at full load. If the calculated gradient is accurate, the tuned system will only provide a reasonable reading at full load under steady state conditions. The accuracy of the reading at loads greater and less than this will depend on many factors including the transformer design and the location of the thermometer. The accuracy of the reading during transitions will depend on the WHS system design.

One of the most common complaints with traditional simulated winding hot spot gauge systems is the tendency of the gauge to stick. This problem has been noted on both new and old transformers and is a cause for concern, especially when the gauge is used for cooling control where a stuck gauge can cause excessive transformer aging or transformer failure.

In addition, WHS analog gauges typically do not provide temperature information in an electronic format that can be transmitted back through SCADA. As a result loading capacity as determined from a remote control room is very conservative.

Electronic temperature monitors (ETM)

The use of electronic temperature monitors (ETMs) has become the standard for many utilities, providing the needed temperature information to their SCADA systems.

The most basic ETM systems operate exactly the same as a simulated WHS gauge, except that the additional temperature rise of winding hot spot over top oil is added digitally in the built-in computer, instead of thermally using a heater. Hence, they calculate the WHS instead of simulating it. More advanced systems incorporate more information, providing more precise hot spot calculations and providing many other diagnostic and communication functions.

One advantage of using an ETM over a traditional gauge is the accuracy. Most ETMs utilise a Pt100 RTD to measure the top oil temperature. The Pt100 has a typical accuracy of +/- 0.2°C. Also it is far more precise to enter the hot spot gradient digitally with a precision of 0.1°C than the trial-and-error mechanical adjustment of a rheostat to probably 2 to 3°C at best.

A second advantage of using an ETM is the ability to tune the time constant of the ETM to match the time constant of the transformer. At loads other than full load, or during thermal transients (heating up or cooling down) the advanced ETM is more precise because it is possible to control the thermal model with regard to how temperature varies with load and time. In a capillary instrument this cannot be controlled.

Basic ETMs

A basic ETM is a very cost effective alternative. For approximately the same price as a gauge, an ETM can provide the electronic output to a SCADA system, improved accuracy and equal or better reliability.

Even the basic ETMs can offer some very beneficial features including OLTC Delta T monitoring But they do not have customised thermal models or predictive cooling control or check and adjust their thermal models based on fan or pump status.

Advanced ETMs or TMSs

Advanced ETMs are now available that provide utilities with high accuracy and more detailed information. The primary benefit of the advanced ETM over more basic systems is its ability to convert the temperature data into useful information that can more easily guide the safe loading and/or maintenance of the transformer.

Following are some of the thermal model enhancements that are available:

WHS per phase: The most basic improvement is achieved through the monitoring or calculation of the load on each of the three phases. Many utilities have applications where the system does not have a balanced load and since most basic ETM systems only monitor one phase, there is a chance that they are not monitoring the hottest phase. Advanced ETM systems can monitor all three phase currents and use either an average load or better yet, a worst-case load in the calculation of the winding hot spot.

WHS per winding: A second improvement is achieved through the calculation of the winding hot spot for each winding. Basic ETM systems are calibrated to only one of either a HV or the LV winding with an assumed tap position. Advanced ETMs calculate the winding hot spot of both the HV and the LV. This may be done by measuring currents in one winding and monitoring the LTC position then adjusting the winding ratio (which affects the thermal model) as the LTC moves. Alternately CTs may be used in both HV and LV. For 3 winding transformers advanced ETMs can calculate the WHS of all three windings using CTs in each, or by calculation measuring LTC position and the magnitude and phase of the currents in two windings.

Adjustments for cooling system health: Arguably, the most important improvement in the thermal model is the creation of separate thermal models based on which stages of cooling are on and working. Advanced ETMs are available which select between different thermal models based on ONAN, ODAN, ONAF, ODAF, OFAN and OFAF and with multiple stages and multiple groups within each stage. With such a system, the ETM will be able to recognise the true WHS given the failure of a fan, pump or cooling system contactor/breaker.

Providing more information: Converting temperature data into useful and actionable information is a key benefit of the more advanced ETMs. Knowing how hot the transformer will eventually become, how long it can safely maintain a load or how much loss of life it has or will incur, can enable engineers to make better decisions.

Ultimate transformer temperatures: In addition to identifying the present top oil temperature and winding hot spot, it is feasible to utilise the thermal model to interpolate the ultimate steady state top oil temperature and ultimate steady state winding hot spot. These calculations are based on the assumption that the load, ambient and cooling system status remains unchanged.

The advantage of knowing the ultimate top oil and WHS temperature is that it provides an early warning of approaching thermal overload conditions and provides a good sense of "how hot the transformer is going to get".

Dynamic rating: The dynamic rating of a transformer takes this one step further. Instead of "how hot it is going to get", dynamic rating tells you "how much load it can carry" or "how long the transformer can continue to carry this load".

Fiber-optic temperature measurement: The thermal models available in the advanced ETMs are quite complex and with modern techniques are quite accurate. However, these calculations are only as accurate as the calibration information used to tune the model.

The calibration information is typically based on the thermal heat run tests conducted at the factory. If the transformer thermal information is not available then this can be obtained by measurement of the transformer behavior over a period of time (say 2 - 3months) and an accurate mathematical extrapolation of a thermal model for the transformer is obtained. Most heat run test reports are designed to meet the calibration needs of the traditional WHS gauges which are calibrated at only one point; full load, all cooling stages on, stead state condition. Newer heat run test procedures provide a time vs. temperature report which is used to program the time constant portion of an ETM system. This added calibration information certainly enhances the accuracy of the ETM. Fiber-optic temperature measurement provides the ability to directly measure a spot temperature of the winding. It is not simulated, not calculated, it is the actual temperature at the spot. This measurement, while dependant on the placement of the probes, certainly complements the calculation method of modern ETM systems and provides additional security. Advanced ETM systems can incorporate this fibre optic measurement and utilise the hottest of its calculated and measured temperatures for dynamic rating purposes.

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Earthing of MV and LV distribution lines - a multi-faceted problem

by Dr. Hendri Geldenhuys and Gareth Stanford, Eskom

Earthing and bonding of systems and the components of (HV-) MV-LV power supply systems require a balancing act between various possible stresses on the system and various fault conditions that can occur in such systems.

This includes step and touch potentials under fault conditions, clearing of faults, the inability of LV systems to clear certain faults, lightning protection, wood pole shattering, leakage current ignition of wood pole members, HV and MV ground potential rise (GPR) faults transferred to the LV system etc.

This paper discusses some of the aspects that must be taken into consideration when bonding and earthing is done in a system, and illustrates these choices with some examples.

Fig. 1 sets the scene of the environment in which safe power system earthing and bonding is to be achieved. The paper discusses the specific issues Eskom must take into consideration when making such design choices. Eskom uses 22 kV system technology primarily for new networks (as well as 11 kV technology where it exists and 33 kV in rare cases) that are earthed through neutral earthing compensators (NECRT) which limit the earth fault current nominally to 350 A. The LV system is earthed according to SANS 0292 (code of practice for the earthing of LV distribution systems) close to the transformer installation to a separate earth electrode with a resistance around 70 or 30 Ω (system voltage and protection dependent) aimed at clearing a MV system fault - contact to the LV system by means of the MV earth fault protection.

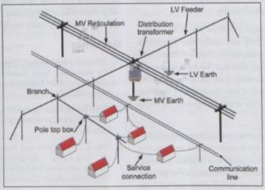

Fig. 1: Ensuring safety and optimum performance: The environment in which a distribution supply system operates includes the service to the customer and his installation (home), and the exposure of the public (in the street). This is impacted by environmental factors such as pollution, lightning, accidents, vandalism, other services etc. (Artwork: A Dickson.)

Power system safety and power system supply reliability

There are primarily personnel and animal safety as well as system continuity of supply and system reliability considerations when designing power system earthing.

Transferred power frequency potential from the MV system

In the case of open wire overhead MV systems (not cables), Eskom uses a neutral arrester to separate the MV earth from the LV earth at a transformer. This is done to isolate any GPR voltage emanating from the MV network to the LV earth system, as this will be transferred directly to the customers on the LV feeders if there is a direct connection between the MV and LV earth. The MV GPR voltages can be a few kV and would be lethal if it occurred while a customer was touching the power safety earth and the local ground at the same time.

This paper focuses on considerations for achieving an optimally safe and (power system) optimal reliable bonding and earthing of a wood pole structure that carries MV, LV and other services at the same time.

LV fault - ground potential rise:

- *LV to MV - LV transformer tank fault:* In the case where a LV to MV transformer tank occurs, a fault condition occurs on the LV system that is currently not protected in overhead power systems. This is however quite a rare event. This is not discussed in this paper.
- *LV feeder neutral break:* Considerations around the risk of the LV neutral break are not discussed in this paper. This is a very significant risk and has to be dealt with by the utility in addition to the issues discussed here.

Use of wood poles

Wood (compared to steel and concrete) has advantages as a structural material for power systems.

Wood poles are extensively used in Eskom for distribution of electricity. The benefit of wood is its mechanical strength and relatively low cost. Also, as it is not an electrical conductor it allows designers more flexibility in designs with respect to the management of bonding and earthing of power systems.

As an example, in the case of single wire earth return (SWER) systems, separate earthing of electrodes as well as making contact to earth electrodes inaccessible to the public is essential for safe design. Wood structures make this easy to do. On steel structures it is impossible to achieve such designs.

This article focuses on the use of wood poles in a village/town or urban, densely populated MV - LV supply installation environment.

Environmental factors to be taken into consideration in bonding and earthing of MV - LV power systems

Lightning on MV systems: 300 kV BIL in high lightning areas

Lightning causes equipment damage, wood pole shattering, short duration interruptions and long-term interruption due to equipment failure. Lightning can also cause deaths of customers connected to power systems and failure of customer equipment connected to the grid.

300 kV BIL philosophy

Do not allow strikes to the ground close to a line to cause a flashover on the line. However,

Fig. 2.

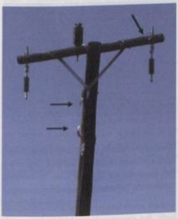

Fig. 3.

in the case of a direct strike to the line it is preferable to have flashover of the line at as low spark over voltage as possible, which will divert the lightning strike energy away from terminal equipment such as transformers and the arresters on the transformers. It should be noted that the lightning arresters at the transformers are not rated to withstand the full lightning current (it will be very expensive to withstand the full lightning current). In this case a power frequency fault will occur which should be cleared by the protection, and power restored quickly and automatically by the auto reclose function on the protection. In high lightning density areas, such as the average for the Highveld of around one direct strike per km of line, there should be around one auto reclose interruption per km of line per year. This sets a benchmark performance for the line with respect to lightning induced auto reclose operations.

This concept of using wood insulation to enhance the insulation level of MV distribution lines dates quite far back in South Africa [1].

Fig. 4: The initial tracking on wood surface in areas where pollution plays a role can be seen in Fig. 4(a). The ignition of the wood and destruction of the structure can be seen in Fig. 4(b). The leakage current is a function of the pollution in the area, the type of insulators used on the structure and the number of parallel leakage paths that are available on the structure.

Shattering of wood by lightning

Lightning can cause severe damage to wood poles as shown in Fig. 2. When the arc travels on the surface of the wood the damage is normally not serious and does not affect the mechanical integrity of the pole. However when the lightning arc travels inside the pole it shatters the wood badly, often destroying the pole completely. Pole shattering is associated with poorly-dried wood in the first year of the line's life and again at the end of the wood pole's life, if the core becomes rotten and moist and creates low breakdown resistance internally in the pole.

It is therefore imperative that wood pole lines are built with poles which are properly dried.

Recently experiments have been done in Eskom with protective spark gaps; attempting to have the lightning spark-over arc kept away from the surface or core of the wood to flash through the air. See the structure in Fig. 3. The hardware

	AC power system related risk		
Design philosophy	**MV conductor drop onto LV system**	**MV conductor contact to BIL down wire only**	**LV contact to BIL down wire**
BIL wires on all shared structures (no gap no insulation of BIL wire).	Fast clearing of MV fault (1 sec). Auto Reclose repeat to lock out. High GPR on LV protective earth. Exposure to all LV installations and BIL wire locations. **Med risk**	Slow clearing of fault (10 sec) even a small risk of not clearing fault. Very high GPR on BIL wire. **Med risk**	Fault not cleared BIL wire stay live. **High risk**
BIL wires only on suspension structures with no stays (no gap no insulation of BIL wire).			Fault not cleared Fewer BIL wires stay live. **High risk**
No BIL wire.		No risk	No risk
BIL wire on all shared structures-insulate bottom 2 m of down wire.	Fast clearing of MV fault (1 sec). Auto Reclose repeat to lock out. High GPR on LV protective earth. Exposure to all LV installations. **Med risk**	Slow clearing of fault (10 sec) even a small risk of not clearing fault. Very high GPR on BIL wire.	Fault not cleared BIL wire not accessible. **Med risk**
No BIL wire - double arresters on transformers on MV side.		No risk	No risk
BIL wires on all – move gap down below LV.		BIL wire will remain live until it flashes to LV protective earth. If Fault to LV occurs-clearing of the fault is the same as column to the left. **Med risk**	Low risk
BIL wires on all – split air gap above & below LV to prevent LV faults.		Low risk	Low risk

Table 1: The AC power system related risks on a shared services wood pole structure bonded in different ways.

Design philosophy	Effective earth	Lightning risk: Consumer lightning risk	Lightning risk: Equipment damage
BIL wires on all shared structures (no gap no insulation of BIL wire).	MV earth + LV earth +BIL wire earths.	Best practice (not totally safe)	Best practice
BIL wires only on suspension structures with no stays (no gap no insulation of BIL wire).	MV earth + LV earth +fewer BIL wires	Best practice (not totally safe)	Best practice
No BIL wire.	MV earth+ LV earth only	High risk	High risk
BIL wire on all shared structures- insulate bottom 2 m of down wire.	MV earth + LV earth only	Best practice (not totally safe)	Best practice
No BIL wire- double arresters on transformers on MV side.	MV earth + LV earth +BIL earths	High risk	Medium risk
BIL wires on all – move gap down below LV.	MV earth + LV earth + BIL earths	Best practice (not totally safe)	Best practice
BIL wires on all – split air gap above & below LV to prevent LV Faults.	MV earth + LV earth + BIL earths	Best practice (not totally safe)	Best practice

Table 2: The lightning-related risks on a wood pole shared structure bonded in different ways.

Design philosophy	AC power risk: MV Conductor drop onto LV system	AC power risk: MV conductor contact to BIL down wire only	AC power risk: LV contact to BIL down wire	Overall risk	Lightning risk: MV conductor contact to BIL down wire only	Lightning risk: LV contact to BIL down wire
BIL wires on all shared structures (no gap no insulation of BIL wire.)	Med	Med	High	High	Low	Low
BIL wires only on suspension structures with no stays (no gap no insulation of BIL wire.)	Med	Med	High	High	Low	Low
No BIL wire	Med	Low	Low	High	High	High
BIL wire on all shared structures- insulate bottom 2 m of down wire	Med	Low	Med	2 Med	Low	Low
No BIL wire- Double arresters on transformers on MV side	Med	Low	Low	High	High	Med
BIL wires on all – Move gap down below LV	Med	Med	Med	3 Med	Low	Low
BIL wires on all – Split air gap above & below LV to prevent LV Faults	Med	Low	Low	1 Med	Low	Low

Table 3: The overall risk: AC power and lightning combined. Where a "high" appears, the philosophy is discarded outright, and the most attractive option is the bottom philosophy option with only one medium risk option.

on top of the structure is bonded with a steel wire running between the insulator mounting brackets. Between this common bond of the insulators to the pole BIL earth wire a spark gap has been fitted.

Wood poles in polluted environments

A second problem that wood poles experience in high pollution areas (and even low pollution areas such as the Kalahari with low rainfall) is tracking, which in severe cases turns into combustion of the pole and even outright pole fires.

In Fig. 5 a structure with five parallel paths per phase to ground can be seen with three different kinds of insulators used. This leakage current occurs in each of the phases and runs along the wood surface (if there were no bonding conductors) between the three phases.

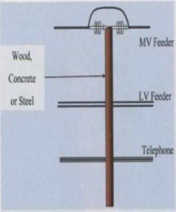

Fig. 6: How do you bond and earth a wood pole structure shared by MV, LV and other services safely and with the lowest network risk?

Fig. 5.

In areas where leakage currents are significantly high, the designer has additional issues to consider:

The hardware at the top of the structure should be bonded to ensure that leakage currents between phases have the opportunity to follow conductors rather than leaking across the surface of the wood. Care has to be taken so that the leakage current at the base of the insulator is effectively "collected" by bonding conductors and should not be allowed to run on the surface of the wood before it leaks into a conductor medium. All the different parts of the structure have to be earthed - not only some of them.

The sum of the leakage currents between the three phases is not necessarily zero.

$$\text{Sum of leakage current} = \sum_{n=a,b,c} \text{phase } n\,(\text{pollution severity, type number of insulators}) \qquad (1)$$

The type of insulators between the outer and middle phase is often not the same. The number of insulators is often also not the same. This leads to a net leakage current to ground. In this case a BIL gap may well be the point where

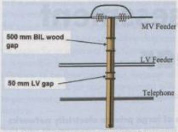

Fig. 7: Optimal bonding and earthing of shared structures in densely populated areas with high lightning density.

such leakage current- tracking and combustion of wood may occur. For this reason BIL gaps in high pollution areas may cause problems and may well not be used.

Bonding of parts of concrete structures

Even concrete structures do not escape the effects of the environment. Incorrectly bonded concrete structures suffer form damage to the concrete as well as burning off of spindles of insulators and the reinforcing steel in the pole. Where no bonding exists, lightning can flash to the reinforcing of the pole and do structural damage to the concrete.

Where poor bonding contact exists, the primary flashover is often caused by lightning (that does not do the damage) but due to the secondary power frequency fault current, welding damage is done to the spindles of insulators and to the reinforcing in the pole.

Lightning personal safety considerations

When a lightning strike terminates on power systems close to points of supply, it does endanger the life of persons (and animals) that are accidentally positioned between the power protective earth and the "local earth".

A direct strike to the power line flows into the system and the lightning caused ground potential rise (GPR) is proportional to the lightning current (median value of 34 k A) and the system resistance (typically 10 Ω), which easily produces a GPR of 340 kV on the LV protective safety earth!

This problem is alleviated by the combined BIL down wires on the line. However it will only be eliminated if the BIL wire earthing was extremely low (much less than 1 Ω per pole; which is not practically possible) so the problems remain. The only effective counter-measure is to couple an extensive protective ring trench earth around the property supplied. (This is the responsibility of the customer.) In addition, if there is no contact between a person and the remote earth, there will not be any risk either; which implies that contact with the power system during lightning storms should be avoided.

In general it has been shown that communities at large are safer from lightning risk in areas where power systems are present compared to a community without the overhead power system. The air termination system and earth electrodes of the power system protects more effectively against the lightning risk, but does not eliminate it and relays the (reduced) risk in a different way.

Example of bonding and earthing of shared structure in a densely populated area with high lightning activity

This section of the paper examines the consequences of the impacts listed above on designing a safe shared services structure, where the MV, LV and other services such as telephone lines share the same structure. The choice a designer is faced with is examined by means of a matrix shown in Tables 1 and 2.

Table 1 examines the AC safety risk impacts and Table 2 examines the impact of lightning on the safety and reliability of the system.

The design approach is listed in the first column of the table. The choices that the designer has are the following:

- To have a BIL down-wire on the pole or not to have one at all (fully insulated pole.)
- Not to install BIL wires on structures that already have "accidental" BIL wires such as stay-wires.
- To insulate the bottom 2 m of the BIL wire.
- To install more effective lightning protection on the line such as the use of double arresters, etc.
- To have additional gaps on the BIL down wire.

All these options are examined in Table 1 and 2 and the consequences are shown. Finally in Table 3, Table 1 and 2 are placed together to show which option provides the best choice. The best choice structure (which still carries risk) is where a double gap is used above and below the LV bundle. This layout is shown in Fig. 7.

	Pollution low	Pollution high
Lighting low	No BIL down wire or bonding of hardware	Bonding of hardware (no BIL down wire)
Lighting high	BIL wire and co-ordinated gap	Bonding of total structure, no gap, high insulator BIL.

Table 4: General rules for the use of BIL wires and bonding of hardware on wood pole structures.

In the case where lightning activity is low, the lightning risk is not a consideration, which then allows the "fully" insulated option.

Notes

LV conductor system: Eskom currently uses LV bundled conductors with a bare neutral or open wire LV on bobbin insulators. In the case of an insulated neutral bundle conductor, it cannot be assumed that the MV fault current will flashover to the LV neutral, and clearing of the fault will be subject to the local earth resistance conditions. It may be unable to clear the MV conductor on the ground.

MV earth and LV earth referrers to the earth electrodes at the pole mounted distribution transformer.

BIL and BIL down wire: "BIL" and "BIL down-wire" refer to the practice in Eskom to install a wire on the surface of MV wood pole structures with a plus-minus 300 mm gap. This gap is normally constructed by applying two banded straps at the end of the wire 300 mm apart. The top of the structure is normally bonded and brought down on the BIL down-wire. The aim is to increase the lightning impulse spark over-voltage from around 170 kV of the insulator to 300 kV from the three phases to ground.

As a general rule for the use of BIL down-wires and bonding of hardware on wood pole structures, Eskom uses Table 4 as a guideline. There is no good structure for all situations; it depends on the pollution and lightning environment and the reliability target that must be achieved.

Conclusion

What appears to be a simple decision has many possible impacts and must be considered carefully. After applying careful consideration to all the factors as shown above, some risk remains. (There are unfortunately no power systems that do not have some associated risk). It should be noted that this paper is not comprehensive and has focused on specific issues. Significant issues not discussed here include breaking of the LV neutral as well as HV and MV GPR fault potential transferred via the LV protective earth.

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Acknowledgements

Bruce McLaren, for the development of the MV structure wood pole protective spark gap.

Andrew Dickson, for the artwork of Fig. 1. Δ

Effective condition assessment of MV switchgear

by Chris Lowsley, Neil Davies and Dawn Miller, EA Technology

There is a general trend within electricity distribution companies and operators of large private electricity networks to extend maintenance periods for MV switchgear. This brings with it a need for interim condition assessment and the application of diagnostic techniques to give confidence in the continuing safety and reliability of the equipment.

There are a number of techniques available for assessing the condition of insulation and the mechanical operation of circuit breakers. Appropriate use of these tools provides valuable data that can effectively target maintenance and ensure resources are more efficiently deployed during outage periods. This paper will describe the most appropriate techniques for assessment of MV switchgear and how data can be collated to provide the best possible information on the condition of the assets.

The drive towards extending maintenance intervals for medium voltage switchgear coupled with the pressure to maximise equipment availability, particularly on industrial networks, means greater reliance must be made on condition monitoring techniques (and in particular non-intrusive techniques) to provide information on the condition of assets and ensure a safe and reliable network is maintained. There are a myriad of condition assessment tools available to provide condition data, however, it is essential that the most appropriate tools are employed and best use is made of the collected data. It is all too easy to concentrate on the collection of data and not turn this into the information required to most effectively manage the assets. The starting point in developing a condition assessment program must be the analysis of historical fault and failure information for similar types of equipment. This will help assess the cause of problems and ensure appropriate weighting is placed on techniques that deal with these causes. Spending 80% of a condition assessment budget to tackle a failure mode that contributes to 5% of failures will not be the most appropriate use of funds.

MV switchgear fault causes

It is sometimes difficult to obtain definitive information on the causes of faults of MV switchgear, however, some information is available and can be used as a guide to typical problems encountered. Fig. 1 shows a breakdown of the causes of faults for MV vacuum switchgear operating on electricity distribution networks within the UK [1]. The fault information shown includes defects identified during operation or maintenance as well as disruptive failure of the switchgear.

Fig. 1 shows that for vacuum switchgear (which will in general have air insulated chambers), the biggest contributor to faults are mechanical problems accounting for 30% of faults, when maloperation is included in this, the figure rises to 38%.

The second largest fault cause was associated with partial discharge activity (26%). It should also be noted that faults reported with cable termination boxes (6%), voltage transformers (VTs) (9%) and current transformers (CTs) (3%) will often be associated with partial discharge activity and therefore the actual figure for partial discharge related problems will actually lie somewhere between 26% and 44%.

Targeting potential mechanical problems and detecting the onset of partial discharge activity are therefore two of the key factors in effective condition assessment of this type of medium voltage switchgear. The general construction of SF6 switchgear is comparable with vacuum switchgear and it is therefore not unreasonable to suggest that a similar fault breakdown will exist with this type of MV switchgear as well.

The situation is slightly different when it comes to oil filled switchgear. A lot of research has been carried out into how bulk oil filled switchgear ages and degrades, and it has been established that the condition of the oil is a key indicator of the overall condition of the switchgear [2, 3].

What analysis of this historical information establishes are the key criteria that need to be considered in any condition assessment program for MV switchgear i.e. mechanical operation, partial discharge activity and in the case of oil filled switchgear, the condition of the oil. It must

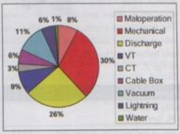

Fig. 1: Composition of faults reported in vacuum switchgear (UK).

also be stated that data from visual examination of the switchgear should also be taken into consideration when developing an overall assessment of the condition of the asset.

Diagnostic tools

An important factor in selecting the most appropriate diagnostic tools is the ability to non-intrusively determine switchgear condition. However in some instances this is very difficult to achieve. For example, in order to effectively assess the condition of circuit breaker mechanisms invariably requires the mechanism to be operated.

It is often possible to switch circuits individually due to the level of redundancy built into networks. Indeed, due to the problems associated with stiction in circuit breaker mechanisms, most UK electricity companies have a policy of regularly exercising the mechanism. Condition assessment should ideally be carried out when the mechanism is being operated for exercise or maintenance.

Provided that the diagnostic tools that are employed do not interfere with the mechanism or auxiliary components of the switchgear then they can be considered to be non-intrusive.

Mechanical monitoring of circuit breakers

The basic principle of mechanical condition monitoring of HV circuit breakers is to detect deteriorating conditions within a circuit breaker operating mechanism prior to any malfunction or failure. In turn, this leads to improved system reliability and more effective maintenance. It is important that diagnostic equipment employed for the assessment of the mechanical condition of a circuit breaker can be used with the switchgear in the service position. The main advantages of testing circuit breakers in the service position are the obvious time savings in not having to isolate the circuit breaker and the fact that the first trip can be monitored. Testing the circuit breaker during operation of the first trip gives an indication of how the circuit breaker would have performed if called upon to trip in an actual fault situation.

There are a number of systems and instruments available for carrying out mechanical testing in the service position. The simplest type of test simply monitors the opening and close times of the circuit breakers. The problem with such a simple device is that it is not possible to diagnose the reason for an abnormal time. Consequently, it is possible for a component with a close tolerance to be deteriorating but, because of other components (or travel movements) with larger tolerances, it may not be possible to detect it.

If a network owner is going to operate a circuit breaker to assess the condition of the mechanism, then ideally as much useful condition information should be derived from the test as possible. For this reason it is preferable for more sophisticated equipment to be employed that will produce additional condition data and help establish the cause of any identified problem. There is now established circuit breaker monitoring equipment in the market that helps with this assessment. In general the equipment works by temporarily (or sometimes permanently) installing sensors on the control circuitry of the circuit breakers to be monitored. Parameters that are monitored include the current profile in the DC trip coil, the current on the secondary side of the ammeter to provide main contact opening time and the battery voltage.

The monitoring systems will capture and store the data from each circuit breaker operation for comparison with previous data from the same unit and also for comparison against other circuit breakers of the same design. The effectiveness of these types of mechanical monitoring systems is therefore dependent on a good background database with which measurements can be compared. Provided this database is available, valuable information on the condition of the mechanical mechanism can be quickly and easily obtained. Fig. 2 shows traces from three consecutive trip operations on the same circuit breaker. The trace shows how the operating time for the first trip (blue trace) is significantly longer than for the subsequent two trips. Knowledge of the system will quickly allow the operator to conclude that the problem was associated with stiction in the slug or plunger. Fig. 2 also shows how the operating time for trips 2 and 3 were back within the acceptable or normal times. This demonstrates why it is important to capture the first trip as this is how the circuit breaker would have operated for a genuine fault on the network.

Partial discharge testing

Partial discharge is an electrical discharge or spark that bridges a portion of the insulation between two conducting electrodes. The discharge can occur at any location within the insulation system (between the two electrodes) where the electric field strength exceeds the breakdown strength of that portion of the insulating material. Discharge can occur in voids within solid insulation, across the surface of insulating material due to contaminants or irregularities, within gas bubbles in liquid insulation or around an electrode in gas (corona activity). Partial discharge may occur in aged, defective or poor quality insulation and can propagate and develop until the insulation is unable to withstand the electrical stress and flashover and failure occurs. When partial discharge activity occurs, it emits energy in the following ways:

- *Electromagnetic:* Radio, Light, Heat
- *Acoustic:* Audio, Ultrasonic
- *Gases:* Ozone, Nitrous oxides

Non-intrusively, the most practical methods of locating partial discharge activity involves the detection of both the radio frequency part of the electromagnetic spectrum and airborne ultrasonic emissions. These techniques are complimentary and their application enables a comprehensive assessment of the condition of insulation on medium voltage switchgear to be non-intrusively determined.

Electromagnetic detection

The most commonly used method for the detection of electromagnetic emissions from partial discharge activity on MV switchgear is through use of instrumentation that uses the Transient Earth Voltage (TEV) measurement technique. When a discharge occurs in the phase to earth insulation of an item of medium voltage plant such as a metal-clad switchboard or a cable termination, a small quantity of electrical charge is transferred capacitively from the medium voltage conductor system to the earthed metal-cladding.

Electromagnetic waves propagate away from the discharge site in both directions. Due to the skin effect the transient voltages on the inside of the metalwork cannot be directly detected outside the switchgear. However, at an opening in the metal cladding, such as the gasketed joint the electromagnetic wave can propagate out into free space. The wave front impinges on the outside of the metal cladding generating a transient earth voltage on the metal surface. Hence the technique is called TEV for transient earth voltage.

The TEV magnitude is a function of the amplitude of the discharge and the attenuation of the propagation path and can be measured with a capacitive probe placed on the earthed metalwork of the switchgear. The technique is particularly useful for the detection of internal partial discharge activity within the bulk of solid insulation e.g. caused by voids and for surface discharge activity to earthed metalwork. The insulation medium of the switchgear is not a critical factor and the TEV signals will propagate from all types of chambers irrespective of whether the chambers are sealed, i.e. the technique can be readily applied to gas

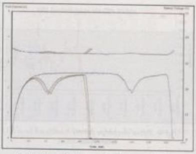

Fig. 2: Trip profile from an 11 kV circuit breaker.

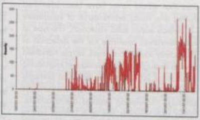

Fig. 3: Partial discharge activity monitored on an 11 kV voltage transformer.

insulated chambers, as well as oil, bitumen and air insulated chambers.

Ultrasonic detection

The sound produced by partial discharge breakdown of insulation can be detected with ultrasonic detectors. In order for ultrasonic detectors to pick up ultrasonic noise, they must be in media of similar densities because the propagation of ultrasonics between low and high density mediums is poor due to most of the energy being reflected. Airborne ultrasonic detectors are therefore successful in detecting surface discharge activity where there is a good acoustic path. For this reason the technique is of little use on gas insulated switchgear or on oil or bitumen filled chambers but is an important tool for the detection of surface discharge within air insulated switchgear e.g. on a dry termination in a vented cable box.

The amplitude of the ultrasonic signal greatly depends on the characteristics of the transducer and instrument as well as the discharge activity and the attenuation of the transmission path. Therefore, quantifying the seriousness of detected ultrasonic signals can be difficult and the fact that ultrasonic activity has been detected can often result in the need for further investigation irrespective of the signal level.

Employing the techniques

The combination of the two techniques is very powerful and allows a comprehensive assessment of the condition of MV insulation to be carried out non-intrusively with no disruption to the network. Ultrasonic detectors identify discharge activity taking place on the surface of insulation and will locate switchgear components that need to be visually examined under outage. The TEV

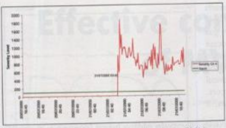

Fig. 4: Partial discharge activity monitored on a 33 kV cable termination.

technique will also detect potential failure sites that would never have been identified during any visual examination of equipment i.e. defects within solid insulation. The type of instrumentation available for the detection of TEV activity varies from small, simple handheld devices through to large permanent monitoring installations [4]. Ultrasonic detection primarily involves the use of hand held instruments although monitoring systems are available. When switchboards are of a critical nature then the cost of permanent monitoring can be justified. Permanent monitoring for partial discharge allows evolving faults to be monitored and can help with the preparation of rectification work to be carried out during planned shutdown periods. Fig. 3 shows an example of one such case. The discharge activity can be seen to develop over a five month period. The problem was associated with a voltage transformer from an 11 kV switchboard and this early warning allowed spare components to be sourced and be ready to be fitted when an outage opportunity became available.

Permanent monitoring also allows quick action to be taken to rectify problems and remove potential faults on critical switchgear if partial discharge activity suddenly initiates or goes through a step change in severity. Fig. 4 shows one example where the level of partial discharge activity on a 33 kV cable termination on a GIS switchboard dramatically increased in severity. The early warning enabled the potential source of failure to be removed from the system within a matter of hours. The benefits of permanent monitoring for partial discharge activity are clearly demonstrated in these two examples and it would be absolutely ideal if continuous monitoring could be incorporated on all MV switchgear. However, in reality this is not a practical or cost effective option. There are however, relatively low cost handheld instruments available that can detect both ultrasonic and TEV activity. Using this type of instrumentation as part of routine substation inspection can greatly enhance the condition information collected during the visits to the substation with minimal additional cost or effort. Therefore, application of partial discharge detection equipment need not be restricted to the most important switchboards on networks but can easily be applied to all MV switchgear on the network.

Switchgear oil analysis

Extensive research into the condition and degradation of oil filled switchgear [2, 3] has revealed that oil condition is the critical factor in determining the need for maintenance. Consequently the performance and degradation of oil has also been studied in detail. One very significant output from this work was the development of specific test procedures designed to maximise the amount of information obtainable from an oil sample from switchgear.

In addition to the measurement of moisture, acidity and breakdown strength, which are standard procedures routinely applied to oil samples, it has been identified that filtration of the sample and assessment of the nature and quantity of solid material recovered gives an indication of the interaction between the oil and materials within the switchgear and therefore the condition of the switchgear internal components. Consequently, oil test results can be used to identify the need for maintenance for individual units. In order to take advantage of this development, a technique was devised to allow oil samples to be removed from switchgear (ring main units and extensible switches) whilst part of the switchgear remained live and supplies were maintained. The process involves access to the oil tank via the test probe access point with only feeder isolation and earthing necessary to open the test access. Therefore the sampling is undertaken when some parts of the switch within the oil tank are live. A reusable cover plate (manufactured specifically for each switchgear type) fits over the test probe access and an oil sample is removed through a specially machined orifice using a sampling tube and syringe. Fig. 5 shows one such cover plate and sampling tube. Two 50 ml samples are removed from the top of the switch tank and analysed with the results being categorised as:

- *Pass:* Indicates satisfactory oil condition, which enables an extended maintenance interval to be adopted.
- *Retest:* Indicates evidence of some oil degradation, should be retested in 30-36 months.

Fig. 5: Test access cover plate and sample kit fitted on a ring main unit.

- *Maintain:* Indicates very poor oil quality, unit should be maintained within 6 months.

Live tank oil sampling has been used successfully with the UK for over 6 years. The process has provided condition information which has been used as scientific justification for many of the UK electricity companies to extend their switchgear maintenance intervals.

Thermal imaging

Infrared radiation cannot directly penetrate metalwork. Therefore the use of thermal imaging equipment, which only measures the surface temperature of components, is not a viable method for diagnosing internal faults in metal-clad switchgear. It is possible for thermal imaging cameras to see through special viewing windows; however, these are not fitted as standard to switchgear and can interfere with type test certification and the internal arc management of switchgear. Detection of faults using infrared techniques also requires line of sight which further limits application and would require extensive use of viewing windows to identify defects in all compartments.

These constraints coupled with the small number of faults attributable to overheating means that the practicality and usefulness of employing the technique on MV metal-clad switchgear is very limited.

However, where these constraints do not exist i.e. on open busbar equipment and low voltage equipment where contacts are, or can be, safely exposed then the application of thermal imaging techniques can have some merit.

Deriving a health index

The diagnostic techniques described above allow useful information to be gathered on the condition of MV switchgear. In certain instances information from a single diagnostic tool will indicate that immediate action is required to bring an item of plant back to an acceptable condition, for example, if there are severe levels of partial discharge activity within switchgear or the condition of the oil is very poor. However, where there is no over-riding factor, best use of the diagnostic data can be made by combining all the available information that relates directly or indirectly to asset condition such as these diagnostic test results, visual inspection data, maintenance experience, causes of previous failures etc. and deriving an overall health index for the assets under review.

The health index is achieved by numerically coding the available information, usually on a scale of 1 to 4, and applying weightings to the factors based on their effect on the probability of failure (POF) of the equipment. The aim is to obtain a value on a scale of 0 - 10 that is 'calibrated' against a consistent relationship with probability of failure.

The concept of a numeric representation of probability of failure is essentially simple but it provides the basis for a very powerful process that enables future condition, performance and risk to be determined for any future management programme. Moreover as the derivation of the health index is based on utilising engineering knowledge, experience and information the final outcome relates directly to engineering reality. This provides results that are both credible and have a clear 'audit trail' back to the original information supported by the most relevant engineering knowledge and experience. The health index value represents the extent of degradation.

Low values in the range 0 - 3,5 represent some observable or detectable deterioration at an early stage, this might be considered normal ageing, the difference between a new asset and one that has been in service for some time but is in good condition. In such a condition, the POF remains very low and the condition and POF would not be expected to change significantly for some time. Medium values of health index, in the range 3,5 - 6,5, represent significant deterioration, degradation processes starting to move from normal ageing to processes that potentially threaten failure. In this condition the POF although still low is just starting to rise and the rate of further degradation is increasing. High values of health index, >6,5, represent serious deterioration, advanced degradation processes now reaching the point that they actually threaten failure. In this condition, the POF is now significantly raised and the rate of further degradation will be relatively rapid.

By creating numeric representation of condition (health indices) and mathematical relationships to link the HI to POF and to estimate changes in HI (and therefore POF) with time provides a powerful basis for modeling future condition and performance. Once the parameters have been set, it is simple to model the future condition and performance of each asset and to estimate the future failure rates for groups of assets. An example of a typical health idex profile for MV switchgear is shown in Fig. 6.

The derivation of a health index and probability of failure for each asset is the first part of a process called condition based risk management (CBRM) which can then be used to evaluate maintenance and replacement strategies in terms of probability of failure and in terms of risk [5].

Condition based risk management (CBRM)

CBRM is a process developed by EA Technology to assist Distribution Network Operators in making asset management planning decisions at a strategic level. It involves combining all available practical and theoretical knowledge and experience of assets to define current condition and then uses this to estimate future condition and performance. In addition it provides a sound engineering basis for evaluating risks and benefits of potential investment strategies. Over a period of several years, EA Technology has developed a working methodology and has practical experience of successful applications. Separate health indices are calculated for each circuit breaker. These are then fed into an overall risk model that takes into account other risk factors associated with the circuit that are unrelated to its condition (e.g. the number of customers connected, or its criticality to the network, etc.). The overall risk model then enables the implications of different investment strategies to be compared on a circuit by circuit basis.

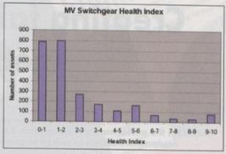

Fig. 6: Example health index for MV switchgear population.

Conclusions

When determining what condition assessment techniques to apply on any asset group, it is important that due cognisance is taken on the causes of faults and failures on the equipment. For non-oil MV switchgear, the majority of faults are associated with mechanical problems and partial discharge problems. It is therefore important to ensure that any condition assessment program utilises techniques to assess the mechanical operation of the switchgear and also assess the condition of the switchgear insulation. For oil filled switchgear, the condition of the oil becomes a critical factor that also must be considered during the assessment program.

Modern diagnostic techniques and methods allow the majority of the key data to be gathered with minimal or no disruption to supply. Therefore, appropriate use of these techniques can provide vital information on the condition of switchgear and help increase equipment availability. There are a number of well established diagnostic tools available that can provide key information on the condition of MV switchgear. Available diagnostic instrumentation ranges from small hand held devices through to full continuous monitoring solutions. What solution is best applied within companies will largely be driven by the number and the criticality of assets on the network. When switchgear is absolutely critical to the network and process, then continuous monitoring may be a viable option. However, the availability of inexpensive hand held condition assessment tools means the techniques can readily be applied to all types of switchgear on the network and can greatly enhance the information gathered during routine substation inspections.

One of the major benefits of using the diagnostic tools is that it provides the operator and owner of electricity networks with confidence in the continuing safety and reliability of the equipment. Where equipment is found to be in an unacceptable condition, maintenance resource can be quickly targeted to ensure that unsafe plant is removed from the network. When the diagnostic data does not highlight switchgear in need of immediate attention, best use of the data can be made by combining all the available information that relates directly or indirectly to asset condition such as the results of the diagnostic tests, visual inspection data, maintenance experience, causes of previous failures etc. This enables an overall health index for the assets under review to be derived and effectively ranks the population of similar assets in terms of condition. This provides invaluable information that will feed directly into maintenance schedules and can help form the basis of replacement/refurbishment plans.

The derivation of a health index is one of the key stages in a process called Condition Based Risk Management which is being increasingly utilised, by owners and operators of MV and HV networks worldwide, to evaluate maintenance and replacement strategies both in terms of probability of failure and in terms of risk. EA Technology's CBRM methodology has been successfully applied with a number of UK Distribution Network Operators as a practical means of meeting strategic objectives and has been well received by the UK electricity industry regulator OFGEM.

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Creating failsafe maintenance methodologies

by PEL Risi, Live Line Technology, and Kevin Risi, DRE Uphando

A sound maintenance program involves creating a statistical framework with which to understand measure, and maintain the performance of equipment. Any electrical network consists of an intricate configuration of electrical equipment working in unison to generate, transmit and distribute electrical supply to the end user.

The reliability of the network's electrical equipment will determine the consistency of supply, that the consumer will receive at the end of the day. It can thus implicitly be said that "reliability is the essence of maintenance."

It is important to take cognisance that breakdowns will always occur at the worst times due to physical exertion of a system, resulting in collateral damage that extends far beyond the original problem.

An example of this could be, the winter of 2010, when millions of soccer enthusiasts enter the shores of South Africa for the Soccer World Cup, and a power failure interrupts the opening ceremony due to peak electrical demand.

Intricate maintenance plans need to be in place to protect the systems integrity. Maintenance plans that extend into 5-year, 10-year and 20-year maintenance plans, to keep current with the growth of an economy.

The attitude of "if ain't broke, don't fix it", has cost companies, incalculable sums of revenue, resulted in licenses being contravened and has meant that the credibility of long, good-standing performance has been ruined.

This so called "breakdown theory of maintenance" has to be examined, understood and overcome so that failsafe maintenance methodologies can be implemented.

The result of a methodical approach, once explored will result in the eradication of the undesireable effects due to the presence of a reliable maintenance program.

The levels of maintenance management

Aging electrical equipment needs to be managed against comprehensive maintenance plans and procedures. The goal is to achieve the maximum amount of lifecycle from the equipment to "sweat the asset" whilst still effectively protecting the asset.

Reactive maintenance
(level 1 – basic)

A crisis-styled maintenance approach to asset management, whereby a response is given to equipment malfunction only once it has transpired. This approach involves the highest amount of risk as no forward planning is presented, and can often indicate an inefficient maintenance department or poor management.

Preventative maintenance
(level 2 – intermediate)

A more systematic approach to maintenance of our electrical networks would start with periodic checks of the system and adjustments to the desired objective.

The advantage of the preventative model is that the discrepancy of the system is more predictable as management begins to implement maintenance methodologies that are more involved and time based, so the risk is removed.

See Fig. 1 which indicates the perceived vs. actual cost for a level of maintenance.

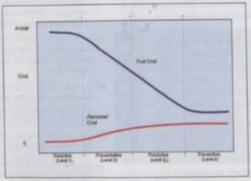

Fig. 1.

Predictive maintenance
(level 3 – advanced)

A defined maintenance program, where periodic measurement of equipment transpires.

Equipment is defined by cost and life-cycles whereby, five, ten and twenty year maintenance plans are implemented. Budgets are set in place to cater for adequate parts and services. Management is involved with total quality management.

Continuous monitoring of process equipment for any abnormal operating conditions. The movement from people-dependant systems to time-directed methodologies is an important step in the removal of risk from the system.

Prevention maintenance
(level 4 – systematic)

This is the most advanced form of maintenance, where technology development plays an important role and where the system is based on minimising the maintenance procedure.

This progression of maintenance has moved from people-directed and time-directed maintenance to condition directed maintenance.

A close relationship with the suppliers/manufacturers of the electrical equipment is required to continually improve on the electrical equipment.

The total quality management has advanced to a process of continually improving equipment.

Although risk will always be a variable that needs to be considered, once it has been effectively minimised, this will be a very reliable system.

Failsafe maintenance methodologies

A very important failsafe maintenance variable to consider is the process of integrating new technology into a utility. This is a collaborative effort that is initiated when the utility identifies a problem and can provide the domain, whilst the manufacturing company provides the hardware and software (product platform) and lastly universities provide the testing facilities.

Technical improvement plans are work practices specifically aimed at making strategic refinements to an electrical distribution network in order to realise tangible benefits such as:

- Meeting current and future technical capabilities of a system.
- Increasing operational efficiency.
- Keeping current with technological advancements.
- Extending the useful life of a system.
- Adding value to the system. eg. conservation of energy.
- Reducing losses and excessive costs.

In an environment where forthcoming engineers and operators do not always get adequate apprenticeships, experience handed down from management or exposure to various system faults, technology development and integration work to compensate for weak areas and improve on current standards. Technology and upgraded hardware can provide a utility with advantages such as:

- Increased productivity.
- Quicker fault clearing and service restoration.
- Improved customer service.
- More powerful design and planning tools.
- The ability to work within smaller margins.

The correct idea would be to do routine technology upgrades to a system to avoid having to do major overhauls, major repairs or replacements.

The movement away from maintenance intensive and sub-standard configured networks is initially a costly exercise, but once traded-off against decreased maintenance procedure times, less pressure on staff, and increased commitment to perform the maintenance procedure, the best possible outcome for an electrical network will be realised.

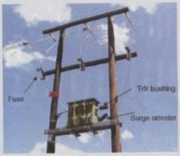

Fig 2: Eskom's configuration D-DT-1860.

The steps for continuous technology development:

- Identify the maintenance constraint.
- Identify the cause.
- Develop a prototype for improving the system.
- Test the prototype.
- Measure desired results.
- Integrate the new technology.
- Measure the improvement.

Case Study : 3 kV - 33 kV surge arrestor maintenance

In the early 1990s, DOC Mining Supplies, a manufacturer of low voltage electrical mining equipment, embarked upon extensive research together with Eskom Distribution, into the excessive downtimes of distribution networks during summer (rainy) seasons.

Eskom's distribution networks range from 3,3 kV to 33 kV, with the majority of these electrical lines being 11 kV and 22 kV networks.

Attention was soon directed to pole mounted transformers and the associated downtimes caused by lightning and over-voltage damage. The main cause was found to be the ineffective surge arrestor maintenance and configuration problems at transformers.

It was during this period that an effort was made within Eskom to improve surge arrestor maintenance mainly on 11 kV and 22 kV Distribution networks.

Pole mounted transformer losses within Eskom distribution was calculated to be **four times** higher than the average utility and this situation had to be addressed.

The most vulnerable periods for over-voltage damage was measured during the rainy months of September through to April each year.

The problems that were identified on these networks with regards to surge arrestors were:

Fig. 3: Phase indicator, connected on a 11 kV and 22 kV distribution line.

- Difficulty in the identification of spent surge arrestors, from ground level.
- The staff's reluctance towards carrying out the maintenance procedures on surge arrestors.
- The time duration of several hours to carry out maintenance (outage time).
- Surge arrestors often didn't blow clear off the lines causing sensitive earth faults (SEFs).
- Safety of personnel was being compromised during the maintenance in rainy conditions.

Reactive surge arrester maintenance (level 1 - basic)

The process of new technology integration began when DOC Mining Supplies researched and developed an overhead phase indicator to reduce surge arrestor maintenance time in configuration D-DT-1860. The phase indicator was developed to provide a visual indication

Fig. 4: The black box phase indicator, connected inside a customer's home.

of a downed phase, by using the corona effect of each working phase, at the pole mounted transformer.

To augment this product, a little black box was placed in the customer's home, to provide a visual indication that one of the phases

Fig. 5: Conventional surge arresters.

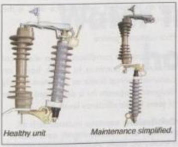

Fig 6. Live line surge arresters.

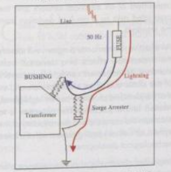

Fig. 7: Eskom's configuration D-DT-1860.

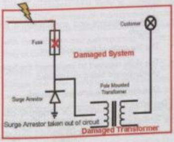

Fig. 7a.

had gone down. This provided even quicker identification, isolation and rectification of the fault.

After two seasons of implementation and measurement it was noted that this reactive response to maintenance was only achieving minimal improvements and was not viable as a long term consideration.

It was thus decided that another approach was needed for management to gain the co-operation of field staff's attitude towards effective surge arrestor maintenance on 11 kV and 22 kV distribution lines.

Preventative maintenance
(level 2 - intermediate)

A more concerted effort was needed to ensure that field staff wouldn't only properly identify the spent surge arrestor but would also be more co-operative in the replacement of these units.

Thus, DOC Mining supplies set out to design a surge arrestor that could be maintained live line without the need of an outage. After just one year of implementation, the results were measured once again and the results were astounding. The return on investment was realised in the first season of their implementation.

Predictive maintenance
(level 3 - advanced)

It was then identified, that the excessive pole mounted transformer losses could be further

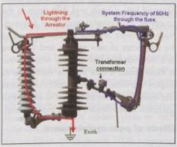

Fig. 8: The transformer combi unit.

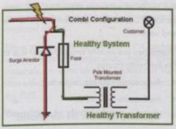

Fig. 8a.

reduced by improving on Eskom's configuration at pole mounted transformers (D-DT-1860).

Engineers working on this project around South Africa, were seeking to remove the reactive and preventative component from their development plans and were looking towards the cause of problems directly relating to the excessive transformers losses and bringing them closer to a prevention maintenance model.

A mathematical model was soon implemented to analyse the properties of the fuse and surge separately and in their fuse-arrestor configuration. It was not long after these steps were taken that it was discovered that the surge arrestor could withstand greater amperages than the fuse over their individual time durations.

A decision was thus taken to correct this configuration to ensure that the fuse would not continually take the surge arrestor out of circuit during electrical storms. It was thus concluded, that the fuse's position needed to be corrected in this configuration.

This configuration performs satisfactory under normal 50 Hz conditions but when exposed to over voltage occurrences such as lightning the vulnerabilities exposed itself in excessive pole mounted transformer losses.

Prevention maintenance -
the final solution

A unit was finally, designed to ensure that the configuration at pole mounted transformers was corrected. The transformer combi unit ensured that the surge arrestor was placed in parallel to the fuse and no longer in a series connection.

This final design not only corrected the fuse and surge arrestor into the correct position, but also ensured that a healthy surge arrestor was also present at all times.

Live line capabilities were a requirement, as well as the unique arrestor alert, which was the indication that the surge arrestor was spent.

The conclusion to the maintenance program was that the surge arrestor could now deal with the over-voltage problems at the pole mounted transformer effectively, bringing about a prevention maintenance approach.

This configuration performs better under normal 50 Hz conditions and when exposed to over-voltage occurrences such as lightning the surge arrestor can now affectively deal with over-voltage occurrences. No more nuisance fuse blows or transformer losses.

Maintenance schedules

The product life cycle of the various equipment within an electrical utility will differ considerably according to the type and use. The maintenance schedule will have to be systematically set-up and accurately recorded into the maintenance database.

Important variables such as the manufacturer's recommendations as to the maximum life of the product in service, the relative importance of the product (primary versus secondary equipment) and according to the exposure to extreme conditions.

Maintenance courses and education

It is important for managers to show their commitment to an effective maintenance program and for this to extend to every staff member in the maintenance department.

Management needs to allocate part of their budget towards the education of every staff member in this department.

Courses and education could be provided by outside contractors, suppliers, trade associations, conferences and publications.

Maintenance audits

An audit is the barometer of success for the maintenance program. An audit will show the real success in terms of continued operation, reduced maintenance costs, reduced downtimes and increased production. Without measurement it is impossible to rate the condition of the equipment and the measure of the system's improvement.

Computer software management

It has become increasingly advantageous for electrical utilities to utilise computing software to manage their infrastructure. Computer software is often capable of acting reasonably on behalf of the user.

Information about the spare parts required, test procedures, historical records and instruction manuals can all be accessed from the enterprise maintenance system. Work orders initiated by computer software management indicates when and where to perform and what kind of maintenance on what devices.

Facilities inspection

A thorough facility and asset inspection periodically is a key element in the maintenance program. This inspection lists the various life safety equipment, line equipment, generation parts, transmission (sub-stations) and distribution sectors.

These inspections should be documented by the duly authorised staff member and summaries should be brought to monthly maintenance meetings.

Provision of spares

The maintenance department needs to be in constant collaboration with the logistics manager to ensure that spare parts are always available. Adequate budgets need to be in place to provide the spare parts and services to make maintenance methodologies work.

Historical records and database development

It is thus imperative to keep accurate records of product life cycles, information on the aging of areas and assets within an electrical network and keeping diagrams/maps of the current network so that a utility can undergo effective maintenance plans.

Gathering data and keeping historical records enables the creation of statistical analysis which is explicit information and the movement towards prevention maintenance.

Management's commitment

A strong management policy establishing leadership and support for the maintenance program is a primary part in establishing an effective maintenance program. Management must communicate its sincere support through an aggressive communication of the policy and procedure to all employees.

Outsourcing of maintenance activities

It often so occurs that there are large scale losses of experienced engineers and operators due to retirement or, as we have seen in South Africa of late, a brain and skills drain to the countries of Australia and New Zealand. New engineers are not always exposed to the intricacies of new systems and therefore lack the expertise that a utility may require. In these cases, it may then be worthwhile to employ a private party to install, commission and maintain certain equipment to ensure that operation is as intended by the manufacturer.

Effects of poor maintenance

Downtime

Reactive styled crisis maintenance plans are the cause of excessive downtime and most certainly cause the most destruction to the end user.

Downtimes are usually brought about due to the following causes :

- Basic conditions are neglected.
- Inadequate skills of staff.
- Operating standards are not followed.
- Deterioration of equipment.
- Quality of equipment compromised.

Degradation of the network

Certain equipment requires periodic maintenance and upgrading otherwise it can be exposed to extreme working conditions or obsolescence. If this is not carried out, then this equipment could start to relay this stress onto other equipment.

Once a system is exposed to excessive stress, a chain reaction of degradation can set into a system.

Damage to equipment

By not maintaining our electrical equipment against the set standards, it will be exposed to conditions outside its scope of design which can result in the product becoming damaged.

Loss of human life

By failing to do maintenance operations at their designated times, we may expose our employees or colleagues to very dangerous circumstances at a later stage. Examples of such an important maintenance duty, is the changing transformer oil.

Poor customer service

The degraded condition of an electrical network, will continue to wreak havoc on customer service levels as a system is only designed to operate for a designated number of years before efficiency levels off.

Conclusion

Sound maintenance methodology involves continuous examination, inspection and assessment of an electrical network and the associated risks as a result of deviation from the standard.

An effective maintenance program will identify the undesirable effects of a deviation from standard. Management needs to keep current of the status quo of an electrical network, so that the identified problems can be highlighted, treated and eradicated. The objective is to maintain the standard and the reliability of the system, as well as keeping current with the latest technological developments.

Important constraints of a maintenance plan include:

- The strategic importance of the equipment.
- Cost constraints and consideration of budgets.
- The life cycle of the equipment.
- The skills required to implement the type of equipment being maintained.
- Duration or time interval required.

A level four maintenance program can be achieved by implementing statistical frameworks, so the strategic importance of each individual line in the distribution network can be mapped and categorised according to a time-based model describing the operating life cycle of each piece of equipment. A sound maintenance programs involves strong management leadership and commitment to creating a statistical framework. It is management's responsibility to implement the necessary time-based maintenance methodologies, against the fixed set of constraints mentioned above.

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Water tree degradation and how to manage it

by Keith Lanan, UtilX, USA

As distribution systems around the world transitioned from PILC to XLPE insulation, they have become vulnerable to water tree degradation. The resulting reduction of system reliability grows steadily year by year. In North America the transition was more than 30 years ago and the water tree problem has become the leading cause of dielectic failure.

Cable manufacturers have largely learned how to build cables that are much more resistant to water trees. A good cable today should perform reliably for many decades. However, the pressure on manufacturers to reduce cable costs sometimes leads to quality problems that will not become apparent until years after the cable is installed. Cables manufactured with defects can show reduced reliability from water trees in as little as five years.

Once a poor quality cable is installed, water tree degradation will slowly reduce system reliability. There are few tools available to system managers who have to manage the results. The extremes of management tactics include wholesale cable replacement or living with the problem and just repairing failures as they occur.

System managers in North America and Europe have been using a method of insulation restoration for many years. The need for this technology is now spreading across the rest of the world following the path of the transition to XLPE 15 and 20 years ago.

Water tree growth

AC stress within homogeneous XLPE insulation of distribution cables is many times lower then levels that can lead directly to breakdown. However, small defects on the surface or in the bulk of the insulation will act as electrical stress risers and focus the stress to very high levels. This will lead to electro-oxidation of amorphous regions in the XLPE and as a consequence a change of properties from hydrophobic to hydrophilic. This promotes condensation of water vapour to form microscopic water-filled voids between the XLPE molecules. This encourages further electro-oxidation and condensation, causing the phenomenon to grow in the direction of the stress. The resulting cloud of voids grows in the shape of a tree and is therefore called a water tree. However, the voids are not interconnected so there is no open channel or trunk to the tree.

Without the defect to focus the stress or water to condense, a water tree will not grow. If either could be controlled after installation, water tree degradation could be controlled and system reliability would be maintained. However, after installation the defects are a permanent fact of life and there are few options to reduce the stress.

Cables can be manufactured and installed completely dry. However, if not protected with a full metal sheath (such as extruded lead), water vapour in the surrounding environment will diffuse into the XLPE until it reaches equilibrium. Most soils and ducts contain close to 100% relative humidity. Consequently, in a few years the insulation will approach 100% saturation. Therefore, there is ample water in the insulation of most cables for water tree growth. Even the humidity in ambient air can be sufficient to promote water tree growth in above-ground insulated cables.

Efforts to keep water out with PE or PVC jackets, water swellable compounds, strand filling materials, or water blocked accessories have little effect on eventual water concentration in the XLPE.

Transition to electric tree

The XLPE within the water tree is still a good insulator. However, it has a lower resistance to discharge than the surrounding insulation. If the stress across the insulation exceeds the reduced discharge resistance of the water tree, a partial discharge is initiated. This discharge will burn an open channel in the insulation called an electric tree.

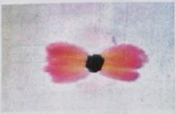


Fig. 1: Bowtie water tree growing from dust particle in six-year old XLPE insulation.

Fig. 2: Small bowtie water trees and large electric tree several centimeters from cable fault.

The resistance to discharge in the electric tree's channel (inception voltage) is lower then in the undamaged water tree. Further discharging is therefore more likely. While discharging, the electric tree will lengthen which lowers the inception voltage further. A small electric tree may exist in a cable for some time as long as the extinction voltage is well above the operating voltage. But, if the extinction voltage drops below the operating voltage, the discharge will continue and lead to failure within hours.

There is a strong correlation between water tree length and AC breakdown strength. As the water trees grow longer over many years, the cable gets progressively weaker. Eventually, the resistance to discharge is reduced far enough that even minor transient voltage events such as switching or grounding will initiate an electric tree.

Detecting water trees

Directly detecting water trees in situ is difficult because water trees have minute electrical signatures. Test systems generally rely on the cumulative property of a characteristic from many water trees to reach detectable levels. But, if there are only a few very bad water trees, the technologies will average the condition over the entire insulation volume and therefore occasionally underestimate the severity of the cable's ageing.

Water trees can be indirectly measured by applying high AC voltage at various frequencies including VLF. The high stress will initiate a partial discharge. If the high voltage is maintained, the electric tree will rapidly grow across the insulation and produce a fault. This is an AC breakdown test or withstand test. It may be compared to having a patient exercise on a treadmill. If the patient has a heart attack, you have confirmed the patient had a weak heart. A variation is to use PD equipment to detect the discharge and immediately shut the test down. This leaves small electric trees behind.

High voltage DC has been used for years for commissioning of new or re-worked circuits to detect large defects such as knife cuts. But the voltage level required for this testing injects space charge that will make water trees more susceptible to discharge when placed back in service. High voltage DC may be valuable for testing new cables. But it is not appropriate for commissioning craftwork on aged cables.

When applied at lower voltages, DC can be useful in measuring the ageing condition of a cable either through leakage current measurement or through measuring the rate of space charge injection (or release).

The only definitive way to directly measure water trees is to send a cable sample to the laboratory for water tree inspection. Water tree staining and visualisation can be done on a sample only a few centimeters long. Samples from fault locations should be regularly inspected for water trees to identify trends. AC breakdown study can effectively measure the effect of water trees. But as it requires many metres of cable and a high voltage laboratory, it is generally only used as a research tool.

The easiest way to gauge the severity of ageing in an XLPE system is to analyse failure history. All cable (and accessory) failures should be documented and categorised by cable type (age, manufacturer, size, etc.) and failure type (external damage, accessory, or otherwise unknown insulation failure). A review of this information along with a few lab tests of failure samples will reveal certain classes of cable that have water tree issues.

Managing system reliability

Managing the effect of water tree degradation is a matter of balancing the value of system reliability against the cost of the remedy. When an XLPE insulated system is young, almost all cable related outages come from mechanical damage. Reliability improvements at this stage focus on reducing the threat posed by excavations along the cable route. Relatively small investments can produce significant improvements.

As the underground system ages, the frequency of outages stemming from water trees increases, adding to the baseline of outages from other causes. At first the water tree- related faults are a small fraction of the whole reliability issue. The cause of these few faults is frequently labelled as unknown and no action is necessary. Even if they are recognised, the cost of proactive intervention is unreasonable. As the system ages further, the percentage of cables with critical water tree problems increases and eventually water trees can become the leading cause of outages.

To maintain the system reliability at a reasonable level while the water tree problem grows necessitates an ever-increasing attention to their resolution. Focusing on installing higher quality cables today can help years from now. But for the cables in the ground, the options are limited to replacement and restoration.

Prioritisation

Circuits within the ageing system must be evaluated to assign a criticality factor associated with the real and perceived cost of an interruption. This is combined with an estimate of the probability of a fault to derive a priority.

Many of the highly critical circuits within a system are already identified through intuitive cues. These are circuits with large customers that are particularly sensitive to outages (industrial complexes, police facilities, government buildings, and healthcare facilities). Other circuits that are intuitively critical are the backbone circuits which would have a large area impact or have no backup (ring main circuits or radial circuits).

The rest of the system must also be assessed to identify where reliability of a particular circuit has higher value. This can be a gigantic task. But, since the water tree problem is age related, the scope of the assessment can be greatly narrowed by setting an age limit. Unfortunately, records of cable age are not always available. In this case a geographic approach looking at the age of development can be helpful.

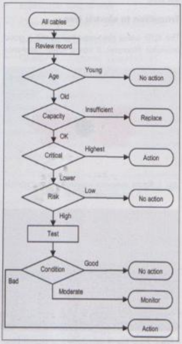


Fig. 3: Prioritisation.

The first step in judging a circuit's potential to fail is reviewing its history. The cable's age is a central factor in water tree-related reliability. But, of equal importance is the original quality of the cable when it was installed. Records should be reviewed to identify groups of cables that should have similar quality issues (manufacturer, insulation type, date manufactured, cable construction).

Failure records must be reviewed to identify particular cables with low reliability. If a cable has had an otherwise unexplained insulation failure, it has a very high risk of failing again. Analysing all failure records along with the associated original cable record will expose groups which had original quality issues and are now at high risk of failure. This leads to recognising marker factors in the original cable records. Sorting the other aged cable records by these markers will reveal groups that have not yet failed but should be suspect.

Testing is expensive and can lead to further problems. Therefore, testing should be limited to only the high risk circuits identified through the record analysis. Testing programs should begin with passive or online systems to narrow the field for further testing (or action). Second level testing can include offline systems with low risk or more destructive systems such as PD measurement.

The reliability of the system related to insulation degradation is dynamic. As the years pass, new groups will reach critical age and some groups will drop from the list when they are replaced or restored. The benchmarks in the decision process will also change as the availability of funds, political pressure, acceptable risk, and the number of circuits that need attention change.

Restoration

When a particular circuit or group of cables reaches the top of the priorities list, its circumstances must be reviewed to determine which course of action is likely to achieve the desired result. The factors that will be weighed in this review include the full cost of the action, the disruption it causes, the availability of funds, and how the use of resources will impact other projects.

In the early stages of system degradation, the higher cost of a few cable replacements can be justified, considering it also provides the opportunity to upgrade the capacity or quality

of the cables, joints, terminations, ducts, or manholes. However, as the water tree problem becomes more pervasive, the number of circuits that must be addressed can overwhelm the available resources. At that point restoration becomes favorable because the lower cost and higher speed of application allows more circuits to be addressed with the same resources.

Restoration is a process of adjusting the chemistry and electrical properties of the cable's insulation in situ. More specifically, a unique silicone fluid is injected through the length of the conductor which then diffuses into the polyethylene, undergoes a chemical transformation, and raises the resistance to discharge. This results in the prevention of faults.

Treatment process

The actual steps used for treatment vary widely to match the circuit and circumstances. Whether treating from termination to termination or from joint to joint, the process can look very different. But, there are basic steps common to all.

Preparation

Circuits are de-energised long enough to modify or replace the terminations (or joints) with equipment that provides an injection access port at both ends of the circuit.

Pneumatic testing

Pressurised air or nitrogen is injected into one end of the cable. If flow is detected coming out the far end, the flow path is established. The entire length is then pressurised to detect any potential leaks. This assures the terminations and any intermediary joints will inject without difficulty.

Joints

Any pre-existing joints on the circuit are carefully identified with a TDR. Most are not designed to contain internal fluid pressure (although some will). Additionally, some types of joints contain materials that are not compatible with the restoration fluid. If the joints on the circuit are a type that is not compatible or they fail the pneumatic testing, they will be replaced with kits that are designed for treatment. These jointing kits are available for installation on critical circuits that may be treated in the future.

Energise or not

The injection equipment and most termination modifications are designed to allow injection while the cable is energised. However, for an added margin of safety, cables are frequently treated while out of service. When treating from joint to joint or from joint to termination, the circuit must remain out of service.

Vacuum

A small tank is connected to one end of the cable and a pump is used to establish a moderate vacuum. This removes air or nitrogen from the conductor to enhance the completeness of the fluid fill. It also assists with moving fluid through the cable.

Fluid injection

At the opposite end from the vacuum tank, a small tank is connected and pressurised to inject a small amount of a desiccant fluid. This will lead the restoration fluid through the conductor cleaning out water and contaminants.

Following the desiccant, a tank of silicone restoration fluid is connected to the inlet end of the cable and it is pressurised with air or nitrogen to the injection pressure. This forces the fluid out of the tank and through the cable. The pressure used depends on factors such as the length of the cable, the available time, joints, and elevation changes. Most injections are completed at 3 or 4 bar. The most common injection equipment is certified to operate up to 8 bar and equipment rated for 23 bar is available for special applications.

Completion

Injection time is highly dependent on the conductor compression. For example: 500 m of typical compressed conductor may complete in twelve hours. The same length of highly compacted conductor may take three days. All three phases are tested and treated simultaneously. Circuits over 5 km have been treated in one piece.

Injection is complete when clean silicone fluid comes through into the vacuum tank at the far end. The injection tanks are removed and the terminations are permanently plugged to contain the fluid.

Preventing faults

Phenylmethyldimethoxysilane is the unique molecule that has been used for restoration for nearly 20 years. Its properties make it uniquely suited for cable restoration:

- In bulk form it is a very low viscosity liquid which allows it to be injected through great lengths of cable at low pressure.
- It is a relatively small molecule and diffuses easily through solid XLPE.
- It reacts (polymerises) with water molecules. In this reaction, the water is consumed and the silicone molecule grows larger.
- The polymerised molecule moves more slowly through the insulation.
- The polymerised molecule remains reactive with water.
- It has a very high dielectric strength.
- It is a strong water tree retardant.

Once the conductor of a cable is filled with the fluid, the restoration of the insulation begins. Over a period of months the silicone molecules diffuse through the conductor shield and into the XLPE insulation. There it encounters resident water molecules. Two silicone molecules react with one water molecule to form the beginning of a silicone polymer chain. In the process the water molecule is consumed and a methanol molecule is produced. This methanol molecule diffuses quickly out of the cable and dissipates into the environment. When the short silicone polymer chain encounters additional water and silicone molecules, the process repeats.

Since the concentration of water in the insulation is highest in the micro-voids of the water tree, more reactions occur there. Additionally, the polymerisation of the silicone makes the molecule larger and dramatically slows its diffusion. As a consequence, the silicone molecules that diffuse through a water tree find ample water to react with and then they essentially lock themselves in place. This leaves a large concentration of silicone in the water tree.

After polymerisation the molecules continue to consume water long into the future, keeping the insulation dry. The CableCURE molecule is also a strong water tree retardant preventing future growth.

After treatment the water in the micro-voids of the water tree is replaced with a high dielectric strength silicone polymer that has particular qualities that prevent discharges. As a consequence, the cable can withstand higher transient voltages without the initiation of electric trees.

Restoration interrupts the usual progression from water tree degradation to electric tree and then failure by blocking the discharge that creates the electric trees.

When compared to replacement, a treated cable can perform with nearly the same reliability. 21 000 km of severely degraded cable has been treated in almost 20 years. More then 99% of this cable is still in service without failure. This matches or in some cases exceeds the record of newly-installed cable.

Conclusion

The frequency of cable failure today is a function of the quality of cables that were installed decades ago. Once the cable is installed, few of the factors that influence water tree degradation can be changed. To maintain an acceptable level of system reliability, managers must assess and prioritise the cables within the system and apply the available tools accordingly. Cable replacement is suitable in the early stages of system degradation or when more capacity is required. As the degradation continues, restoration becomes increasingly viable to maintain the desired level of system reliability with finite resources. Δ

Electrical accident safety briefings

Eskom Fatal Accident

by Colin Smith and Koos Krafft, Eskom

Staff at Eskom were shocked by the circrumstances leading to the death of an Eskom employee who was thought to be a diligent worker. The incident tested the understanding of the objective for earthing and resulted in a major review of earthing practices in the business.

Earthing defined

Earthing is the primary method employed by electricity utilities the world over to secure a safe environment for their staff working on apparatus of an electrical network. It is a fundamental precaution specified by the General Machine Regulation 5(2) incorporated in the OHSA.

Definition of earthing

Earthing is defined as "the connecting of apparatus electrically to the general mass of earth in such a way that it will ensure an immediate and safe discharge of electrical energy at all times" (NRS 042 -3) .

Definition of equipotential zone

"A safe work area created to ensure that any two or more conducting parts that can be touched by a person simultaneously are bonded together by approved earthing leads to ensure a zone of equal potential between different parts of the working area" (NRS040-3).

Objective of earthing: the popular perspective

The bridging of all the phase conductors and connecting them to an earth electrode at both sides of the workplace in order to provide an equipotential zone and secure the safety of staff.

Objective of earthing: the right perspective

The objective of earthing is to devoid the work area on electrical networks of 'step' and 'touch' potentials. This process is much more complex than the popular interpretation leads on.

Incident recall

A work team was instructed to replace bolted connectors with crimped sleeve joints on the jumpers of the overhead conductors of an 11 kV power line. The 11 kV supply breaker was opened, the line was isolated and earthed at the substation. A principal technical official (a certified professional engineering technician) did the following earthing after the line was proven dead, prior to the commencement of the work:

- He inserted an earthing electrode into the ground at the base of a wood pole.
- He then connected one side of two long earth leads to the earth electrode and to the other side of a phase on either side of the work place/structure.
- Specially provided bonds were used to short the phases at both sides of the work place so that all were connected to earth
- While this was in progress, a mobile equipment operator introduced a cherry picker onto the work site. It was equipped with an equipotential footplate and earth. He earthed as follows:
- Removed and placed the foot-plate on the ground. The latter was electrically connected to the vehicle chassis and an earthing electrode.
- He installed a second earth electrode into the ground approximately 7 m from the electrode installed by the authorised person. Finally, he connected the vehicle earth to the earth electrode.

From the perspective of the authorised person on site (also the deceased) this completed the earthing in preparation for the work. The principal technical official got into the cherry picker and started to replace the PG clamps with compression joints together with another person in the cherry picker.

The 66 kV earth fault

At the time of the incident, an earth fault developed on a 66 kV line approximately 2 km from the work site. The fault developed as follows:

- A jumper clamp failed on the 66 kV line and a centre phase jumper separated.
- It momentarily touched the structure when it swung out to a rest position clear of the structure.

Note: It was a lattice steel structure earthed at the base.

The SCADA indicated the time of the 66 kV line fault (trip and auto-reclose) to coincide with the time that the deceased was holding the clamp on the line in order to be crimped by the second person in the bucket.

Facts obtained from the incident investigation

- Two earth electrodes were installed at the work site.
- The earth resistance between the earth electrodes were 640 Ω.
- One of the earth electrodes was installed in virgin soil while the other was installed in disturbed soil.
- Both electrodes were inserted to a depth less than depth prescribed.
- Employing the two 750 mm earth electrodes is not in compiance with the Eskom earthing standard which specifically calls for a common earth electrode.
- The technician in control of the work-site and those persons who responded initially to the incident notification failed to identify the touch potential situation created by the two earth electrodes.

Immediate causes of the accident

Both the 11 kV and 66 kV line originated from the same substation and were effectively earthed to the substation earth mat. The earthed line connected through the substation earth mat presented an ideal earth return path for the source transformer from the 66 kV line fault.

The earth fault current divided between the parallel earth paths created as follows at the work site:

From the earth, through the earth electrode introduced at the pole base, the earthing leads through the line to the excellent substation earth, the overhead guard wire on the 66 kV line and back to the source transformer, which was solidly earthed on the 66 kV side, and the second earth path.

From the earth, through the cherry picker earth (7 m away from the electrode at the pole base) through the vehicle mounted crane arm, the buttocks of the deceased, through his body onto the conductor and the rest of the return to the source transformer.

Root cause of the incident

The root cause of the fatality was the introduction of a touch/step potential as a result of the second earth electrode being introduced at the place of work.

Learning point

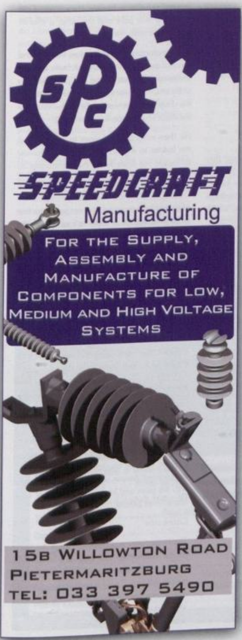
The learning point does not constitute new knowledge - it is a painful reminder of a well documented phenomenon. Lack of

Advertorial

SPEEDCRAFT MANUFACTURING – LOCAL SUCCESS IN SOUTH AFRICA.

Empowerment of the disadvantaged is at the forefront of South African commerce and industry as the country continues along the path of its transformation process. Eskom, as a parastatal corporation, is particularly vigorous in its pursuit of these ideals and places a high premium on black and particularly black woman ownership of businesses with whom they deal. Because of the obvious benefits such as job creation in large numbers, they also prefer to deal with empowered companies that are also bona fide manufacturing operations. Speedcraft is one such manufacturing concern which together with its new ownership structure, ensures a very high rating on the supplier ranking system used by Eskom.

In line with the commitment by the South African government to empower black people, more specifically, women, and to encourage foreign investment Speedcraft and the German based Pfisterer Holdings have formed a 50-50 partnership.



The partnership between these companies was borne out of Eskom's mandate to empower black business and their encouragement for the two to formally join forces. Pfisterer Holdings unreservedly endorses the principles and values of black economic empowerment in South Africa. Speedcraft is quickly transforming itself into a company where women are in the majority and the ultimate aim is for the company to become a company, managed and staffed entirely by women. In keeping with this vision, Ms. Orene Mnguni in her position as Managing Director and 50% shareholder is working hard to accelerate the process. Ms. Mnguni has the ability to contribute significantly and add both personal value and empowerment to the company.

Speedcraft Manufacturing (Pty) Ltd is primarily a manufacturer of metal hardware, all of which has applications in the electrical transmission and distribution industry. Speedcraft is now also a member of the German based Pfisterer Group of companies, which is a leading global manufacturer and supplier of components and systems for energy networks. It is out of this partnership that Speedcraft will benefit from transfers of technology and skills that will allow the company to expand its manufacturing capabilities. Speedcraft has positioned its own production facilities within close proximity to the Pfisterer premises in Pietermaritzburg, thereby enabling the company to make use of that infrastructure and to facilitate additional transfers of skills in various areas of its operation.

The company enjoys access to a wealth of expertise and support from within the Pfisterer Group and is ideally positioned to continue growing from strength to strength as a leading supplier of transmission and distribution hardware and as a contributor to the ideals of black empowerment in South Africa.

Staffing of the company continues to grow in order to meet the expanded manufacturing capacity required to meet increased local market demands and new local business from municipalities and Telkom SA, as well as positioning the company for future opportunities in export markets. The company has major contracts with Eskom and has been recognised as one of Eskom's few 5 star rated BWO suppliers. Speedcraft has earned ISO 9001 2000 certification from the German accreditation company DQS.

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understanding of the earthing requirement and the resultant introduction of the two separate earth electrodes at the work site was the cause of the incident. Hence this paper is a reminder of the risk, even though the exposure window is small, that this type of coincidental exposure is possible.

It is critical that you urgently convey to your staff the message that only one earth electrode must be used for earthing at every work site and that the introduction of a second earth electrode (earthing point) could be fatal.

Accident at Buffalo City

by Terence Lee

This presentation gives an outline of a recent accident which recently took place in Buffalo City. The accident was the catastrophic failure of an 11 kV switch panel at the Chiselhurst Substation in East London.

Chiselhurst Switch House fault

Chiselhurst Switch House was constructed about 38 years ago. It provides electricity supply to about seven suburbs, parts of the central business district, the Frere Hospital and the commercial area in Vincent. It has a firm capacity of 32 MVA and is located adjacent to a 132/33 kV substation known as Stoneydrift.

The South Wales 11 kV board consists of:

- 3 Incoming circuit breakers each supplied from a 33/11 kV 16 MVA transformer
- 2 Bus section circuit breakers
- 14 Feeder circuit breakers

Circumstances surrounding the failure

The Vincent No. 3 feeder cable had previously faulted. The remaining two feeders to Vincent Switch House are of unequal cable size and therefore do not share the load equally i.e. one 300 mm² and the other 120 mm². In order to prevent overloading of either of the two feeder circuits to Vincent, the circuit breakers were evidently operated simultaneously. The result of this was an explosion which caused major damage to one section of the switch board.

Sequence of events: First fault

Vincent No. 1 circuit breaker was closed together with Vincent No. 2 circuit breaker. Vincent No. 1 circuit breaker developed a fault on the feeder side of the breaker and tripped. The fault was sustained via the Vincent No. 2 cable as the bus section switch was closed at the Vincent Switch House.

Sequence of events: Second fault

A secondary busbar fault developed after a period of about 30 min. The 33 kV circuit breaker supplying the 16 MVA transformer failed to trip and had to be operated manually. The entire board was then isolated and the clean-up process was commenced.

Other factors

The Switchgear fault was attributed to an annealed Tulip Connection on the No. 2 Vincent feeder. This is of concern as a similar fault occurred on the same switch board in 1999.

Conclusion

The entire switch board is considered to have reached the end of its useful life and will be replaced. The operator spent three months in hospital and sustained serious burns on his body, hands and legs. He is still undergoing treatment for his burns, but the psychological scars may take much longer to heal.

Accident at Great Brak River, Mossel Bay

by Dick Naidoo

A senior electrician from the Mossel Bay eastern region sustained serious injury (broken leg, ribs and punctured bowel) when he fell to the ground whilst replacing a low voltage distribution box on a wooden pole, which broke at the base.

The wooden pole, which forms part of an ABC strain assembly was also supported by a stay wire which sheared at a weak point. The electrician worked on the same pole a week prior to the incident and therefore misjudged the integrity of the wooden pole and stay wire which were erected on an island with a high water table.

An investigation revealed:

- That a week prior to the incident the electrician worked on the same pole and tapped the pole with a mallet to ascertain whether the inner core of the pole had decayed. As he did not hear a hollow sound from the pole, he assumed that the pole was healthy.
- That because the stays were covered with creepers the electrician neglected to examine the condition of the stay. It was discovered that the stay had deteriorated extensively and was on the brink of failure.

Lessons from this incident

- A decayed pole in a water logged environment may not give off a hollow sound when tapped with a mallet.
- Electricians should be constantly alert to hidden defects. A severely rusted stay wire amongst vegetation is a potentially dangerous condition.

Accident at Drakenstein Municipality

by Jan Coetzee

On a Monday, after a stormy weekend in May 2006, during which Drakenstien Municipal teams worked most of the weekend to attend to all of the storm damage, a senior electrician and his helpers went out with their crane-truck to replace a faulty pole transformer. It was a normal installation where the transformer was situated on a rack between two poles. One being the line pole and the other a shorter pole underneath the line.

The transformer was well below the line and was fed through three dropout fuses situated underneath the line on the line pole. Arriving at the site, the senior electrician made sure that the drop out fuses were pulled open and that the main low tension switch was off.

He then ordered his helper to advance up the ladder to the bottom of the transformer to loosen the bolts fixing the transformer to the rack. While he proceeded to put out the supports on the truck for the crane.

After that he was going to arrange for the line to be switched off in order to manoeuvre the crane above the transformer to lift it off.

Next thing there was a noise and the helper was found lying on top of the transformer. He was unconscious for a while and was badly burned. He was taken to hospital and underwent skin transplants.

Nobody saw what happened and the helper cannot remember. He does remember that the dropout fuses were open and that he went up the ladder to undo the bolts on the transformer rack but he cannot remember why and how he got on top of the transformer and what happened thereafter.

Because the line is quite high above the transformer, it is assumed that he made contact with the upper part of the dropout fuses with the back of his right hand. He is a well experienced person who has been five years with the team and had done this kind of work many times before.

Conclusion

The helper was supposed to loosen the bolts on the transformer rack only, why he climbed on top of the transformer, nobody not even he can explain. Could it be that he was tired/overworked because of the repair to much storm damage and his concentration was therefore at a low level? Δ

Closing words from the Affiliates

by Clive Burchell, acting chairman, AMEU Affiliates

As we come to the close of this 21st AMEU Technical Convention it is indeed a great honor for me to address you on behalf of the AMEU Affiliates.

I think back to the Technical Convention held in Mossel Bay in 2000, when I was asked by Trevor van Niekerk to make the closing address on behalf of the Affiliates, as it was to be my last convention before my official retirement. I was then vice chairman of the Affiliates. Little did I know that in 2006, circumstances would put me in this position again. This time, as acting chairman of the Affiliates, due to the sad passing, after a long illness, of Chairman Trevor van Niekerk. Time has taken its toll. In 2000 we, as Affiliates, had a membership of 160 companies. Now we have a membership of 104 companies. Nevertheless we have a dedicated steering committee and active participation by members at our regular meetings.

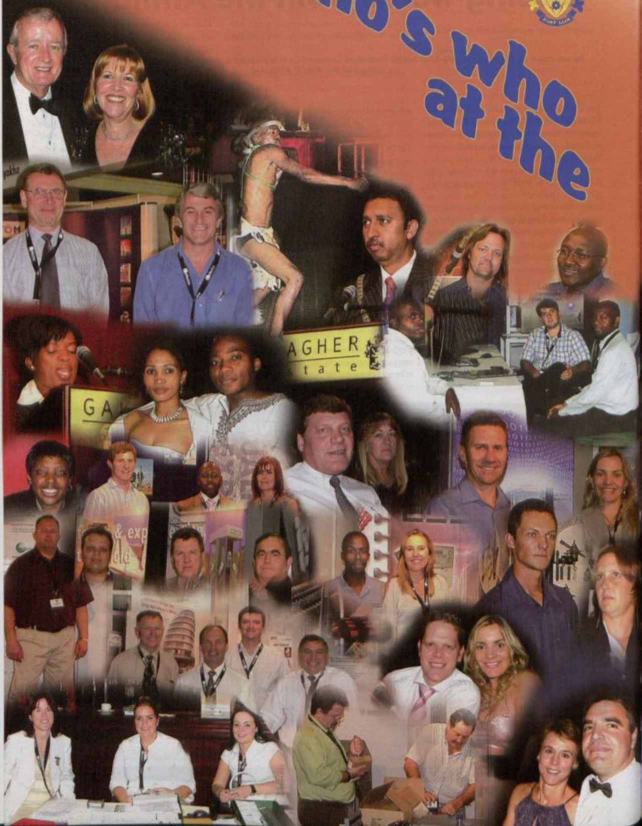
The Affiliates continue to play a major role in the branch activities in presenting papers and exhibiting their latest technology, often outnumbering engineer members at branch meetings. I believe that our sports day, organised and funded by the Affiliates, was once again a huge success, and in spite of time constraints, was enjoyed by all who participated. I would like to thank Jacqui Burn for organising the venue and the bowls, under the watchful eye of Max Clarke. Thanks also to Mike Cary of Rotek for his continued sponsorship of the hike. Thanks too to Dawie van Niekerk for taking charge of the golf. I wished I was able to play!

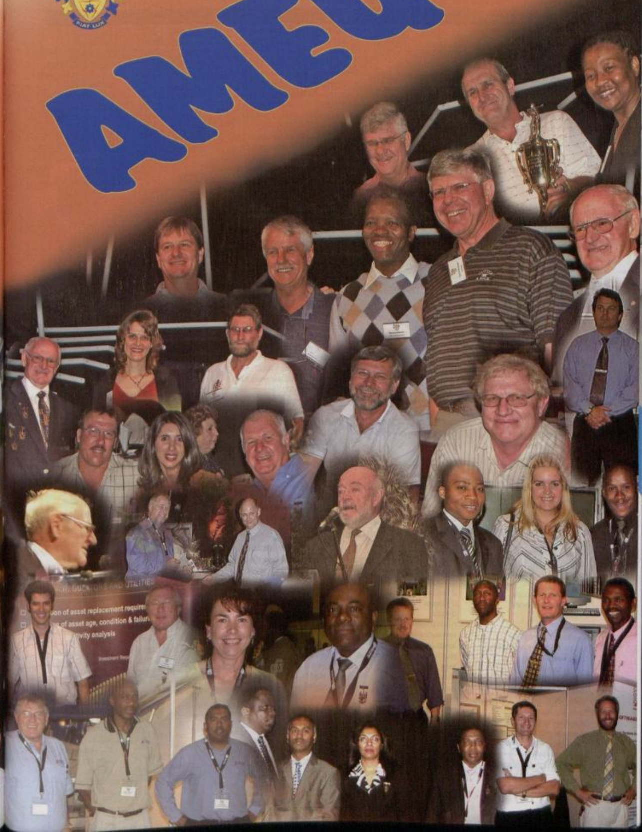
The dinner the "Midnight Hour" show at the Sound Stage was thoroughly enjoyed, and set the theme for the three days to follow. I thank Jacqui Burn for her efforts in the organisation of this event. The Affiliates exhibition this year comprised 57 indoor stands and one outdoor. A total of 50 companies exhibited. This is an all time record. I congratulate Bob Wallis for a job well done, and thank the exhibitors for their support. I believe we can be proud of the professional level of the exhibition.

I look back at the closing remarks I made six years ago, and thought then that there seemed to be encouraging signs that the pace of change in our industry was increasing. I regret to say, after much talk, many meetings and six years later, I believe we remain in trouble, and are far from a viable solution for the industry. We hold our breath for the cabinet announcement from Cape Town. Let me assure the AMEU that we, your Affiliates, together with the unique association we share with each other, will play our part in ensuring we build a strong and reliable electrical supply industry, whatever the final structure is.

On behalf of the Affiliates, I would like to express our thanks to Vally Padayachee and his team, and to Jean Venter, Gillian le Cordeur and their team for the excellent organisation of this convention. It was a great pleasure working with you. Mr. President, I wish you all the best for the remaining term of your office. To the steering committee of the Affiliates, thank you for your loyalty and support. Lastly to my wife, Elize, who thought that six years ago she would at long last have more time with me, thank you for your patience and support over the past 46 years. Δ

Who's who at the AMEU





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Syntell	Julia Williamson	P O Box 30451, Tokai, 7966	julia@syntell.co.za	(021) 710-2044	(021) 710-2851
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Tasselane	Charles Koapeng	P O Box 14, Wendywood, 2144	ckoapeng@tasselane.co.za	(011) 461-1800	(011) 461-1808
Tridonic Atco SA	Trevor Milne	P O Box 123, Gatesville, 7766	trevor@tridonic.co.za	(021) 637-8000	(021) 637-4501
Ukubona Electrical	Bill Greyling	P O Box 9442, Edenglen, 1613	bill@ukubonaelectrical.co.za	(0121) 608-4736	(011) 608-4741
Ulungeni Consulting	Jan Jordaan	P O Box 1521, Empangeni, 3880	ulungeni@iafrica.com	(035) 792-1026	(035) 792-2283
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1991 & 1998	AHL Fortmann	Boksburg
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JAD Foubister	SABS
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WP Rattey*	Strand
Prof. K Van Alphen	SABS
Jan Venter	Cape Town
14th Technical Meeting - August 1992	
William Lashley	GEC
Emil de Villiers	Rustenburg
15th Technical Meeting - August 1994	
Ald Frikkie Kotze*	Port Elizabeth
J van Soelen Lochner	Pietersburg
William Tindle	Reyrolle
16th Technical Meeting - October 1996	
KJ Murphy	Somerset West
PJ Muller	African Cables
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