COURT ONLINE COVER PAGE

IN THE HIGH COURT OF SOUTH AFRICA
Gauteng Division, Pretoria

CASE NO: **2022-061920**

In the matter between:

Sakeliga NPC,Agri North West,TLU SA,Magaliesberg Citrus Company (Pty) Ltd	Plaintiff / Applicant / Appellant
and	
Eskom Holdings SOC Ltd,The National Energy Regulator of South Africa (NERSA),The Minister of Mineral Resources and Energy	Defendant / Respondent

---

Review

NOTE: **This document was filed electronically by the Registrar on 22/12/2022 at 11:31:00 AM South African Standard Time (SAST). The time and date the document was filed by the party is presented on the header of each page of this document.**

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA

Private Bag X67, Pretoria 0001

THE JUDICIARY
REPUBLIC OF SOUTH AFRICA

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA

ELECTRONICALLY SIGNED BY:

Registrar of High Court of South Africa , Gauteng Division,Pretoria

IN THE HIGH COURT OF SOUTH AFRICA

GAUTENG DIVISION, PRETORIA

CASE NO.: ___________/2022

In the application between:

SAKELIGA NPC	1st Applicant
AGRI NORTH WEST	2nd Applicant
TLU SA	3rd Applicant
MAGALIESBERG CITRUS COMPANY (PTY) LTD	4th Applicant

and

ESKOM HOLDINGS SOC LTD	1st Respondent
THE NATIONAL ENERGY REGULATOR OF SOUTH AFRICA (NERSA)	2nd Respondent
THE MINISTER OF MINERAL RESOURCES AND ENERGY	3rd Respondent

NOTICE OF MOTION

BE PLEASED TO TAKE NOTICE THAT the applicants intend to make application to the above Honourable Court, on a date and time to be arranged with the Registrar, for an order in the following terms:

1 **THAT** the 1st respondent's policy and action of the 1st respondent to apply periodic and/or scheduled and/or *ad hoc* load reduction to so-called high-loss feeder lines, alternatively to feeder lines where the 1st respondent is experiencing high electricity use losses, further alternatively to the feeder lines stated in paragraphs **Error! Reference source not found.** and **Error! Reference source not found.** of the founding affidavit (the "**load reduction policy**") be declared to be unfair, unreasonable, irrational, *ultra vires*, unlawful, unconstitutional and be reviewed and set aside.

1 **THAT** the first respondent's decisions to apply load reduction to feeder lines across South Africa, alternatively, the feeder lines referred to in paragraphs 41 and 86 of the founding affidavit, constitutes unjustifiable and unidentifiable discrimination and differentiation between customers or classes of customers regarding access and conditions of service and be declared unconstitutional, unlawful and be reviewed and set aside.

2 **THAT** load reduction as a credit control and/or debt-collection mechanism aimed at recovering or curtailing usage by non-paying direct customers on feeder lines, be declared to be unconstitutional, unlawful and be reviewed and set aside in as far as it has the consequential effect of also reducing or terminating the supply of electricity to paying direct customers on the same feeder line.

3 **THAT** it be declared that the first respondent's load reduction policy and action in terms thereof, is in contravention of sections 21 (2) and 21 (5) of the Electricity Regulation Act 4 of 2006, and is unlawful and be reviewed and set aside;

4 **THAT**, in the alternative to paragraphs 1 - 3 above, the applicant seeks an order in terms of section 172 of the Constitution that is just and equitable, and which has a remedial effect alleviating the Constitutional infringements, concerns and/or invalidities underlying this application.

5 **THAT:**

5.1 The first respondent pay the costs of this application, such costs to include the costs consequent upon the employment of two counsel were so employed, and,

5.2 in the event of opposition by any other respondent, such respondent be directed to pay such costs jointly and severally with the first respondent, one paying the other to be absolved.

6 **THAT** the applicant be granted such further and/or alternative relief as the Court deems meet.

KINDLY TAKE FURTHER NOTICE that the first respondent is called upon, in terms of Rule 53(1)(a), to show cause why the aforementioned decisions and/or provisions should not be reviewed and set aside.

KINDLY TAKE FURTHER NOTICE that in terms of Rule 53(1)(b), the first respondent is required to dispatch to the Registrar of this Honourable Court, within **15 (fifteen)** days after the date of service of this notice of motion on the respondents, **<u>the record(s)</u>**

<u>of all documents relating to and/or relied upon</u> in the making of the decisions and execution of the functions sought to be reviewed, **<u>together with such reasons</u>** as the first respondent is by law required or that they desire to give or make.

TAKE FURTHER NOTICE that in terms of Rule 53(4) the applicant may, within 10 (ten) days after receipt of the record(s) from the Registrar of this Honourable Court, by delivery of notice and accompanying affidavit, amend, add to or vary the terms of the notice of motion and supplement the founding affidavit.

TAKE FURTHER NOTICE that the founding affidavits of **TOBIAS VIVIAN ALBERTS**, with attachments thereto, which are annexed to this notice of motion, will be used in support of the relief sought herein.

BE PLEASED TO TAKE NOTICE that the applicant hereby appoints the address for service of all processes and documents in this application, the address of **KRIEK WASSENAAR & VENTER INC, 13 STAMVRUG AVENUE, VAL DE GRACE, PRETORIA** (reference: **P WASSENAAR / QB0973**) as set out hereunder.

TAKE FURTHER NOTICE that if you intend to oppose this application, you are required to:

(a) Within 15 (FIFTEEN) days after the date of receipt of this notice of motion or any amendment thereof as contemplated in Rule 53(4), to deliver a notice to the applicant stating that you intend to oppose this application and in such notice, appoint an address within 15km of the office of the Registrar of this Honourable Court; and

(b) Within 30 (THIRTY) days after expiry of the time period referred to in Rule 53(4), deliver such answering affidavit(s) or other affidavit(s) together with any relevant documents as you may desire in answer to the allegations made by the applicant in the founding affidavit or any amendment or supplementation thereof.

KINDLY TAKE FURTHER NOTICE that if you fail to notify the attorney for the applicant of your intention to oppose the application within 15 (FIFTEEN) days after the date of receipt of this notice of motion and/or if you fail to serve and file an answering affidavit within 30 (THIRTY) days after expiry of the time period referred to in Rule 53(4), this application will be set down on the unopposed motion roll on a date to be arranged with the Registrar.

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA
Private Bag X67, Pretoria 0001
REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA

DATED AT PRETORIA ON 21 DECEMBER 2022

KRIEK WASSENAAR & VENTER INCORPORATED
ATTORNEYS FOR APPLICANT
Third Floor
Hb Forum Building
13 Stamvrug Road
Val De Grace
Pretoria
Tel: 012 756 76566
Fax: 086 596 8799
E-Mail: peter@kriekprok.co.za
nj@kriekprok.co.za
REF: **P.J. WASSENAAR/ QB0973**

TO: **THE REGISTRAR OF THE ABOVE HONOURABLE COURT**
PRETORIA

AND TO: **ESKOM HOLDINGS SOC LTD**

FIRST RESPONDENT

MEGAWATT PARK,

MAXWELL DRIVE,

SUNNING HILL EXT 3

GAUTENG **SERVICE BY SHERIFF**

AND TO: **THE NATIONAL ENERGY REGULATOR OF SOUTH AFRICA (NERSA)**

SECOND RESPONDENT

526 MADIBA STREET

ARCADIA

PRETORIA **SERVICE BY SHERIFF**

AND TO: **THE MINISTER OF MINERAL RESOURCES**

AND ENERGY

THIRD RESPONDENT

TRAVENNA CAMPUS,

BUILDING 2 C

corner MEINTJES STREET

& FRANCIS BAARD ST

PRETORIA **SERVICE BY SHERIFF**

IN THE HIGH COURT OF SOUTH AFRICA

GAUTENG DIVISION, PRETORIA

CASE NO.: ____________________

In the application between:

SAKELIGA NPC	**1st Applicant**
AGRI NORTH WEST	**2nd Applicant**
TLU SA	**3rd Applicant**
MAGALIESBERG CITRUS COMPANY (PTY) LTD	**4th Applicant**

and

ESKOM HOLDINGS SOC LTD	**1st Respondent**
THE NATIONAL ENERGY REGULATOR OF SOUTH AFRICA (NERSA)	**2nd Respondent**
THE MINISTER OF MINERAL RESOURCES AND ENERGY	**3rd Respondent**

FOUNDING AFFIDAVIT

Contents

I, the undersigned,

TOBIAS VIVIAN ALBERTS

state under oath as follows:

1 I am an adult male legal officer at Sakeliga NPC (registration number 2012/043725/08), being the 1st applicant in this matter. The 1st applicant has its principal place of business at 416 Kirkness Street, Arcadia, Pretoria.

2 The facts set out in this affidavit fall within my personal knowledge, save where the context indicates otherwise or has been made known to me in the course of the business of the 1st applicant. Where the contents do not fall within my knowledge, I refer to confirmatory affidavits of persons who possess such knowledge.

3 I am duly authorised to attest to this affidavit on behalf of the 1st applicant. I attach proof of my authority hereto as annexure **X1**.

4 To the extent that this affidavit contains matters of a legal nature, the 1st applicant relies on the advice of its legal representatives, Kriek Wassenaar & Venter Inc ("**KWV**"), which I believe to be correct.

5 Supporting affidavits for the 2nd – 4th applicants will be attached to this affidavit.

THE APPLICANTS:

The 1st applicant

6 The 1st applicant is **SAKELIGA NPC**, with registration number 2012/043725/08. The 1st applicant is a non-profit company duly registered and incorporated in terms of the company laws of South Africa and has its principal place of business at Building A, Fifth Floor, Loftus Park, 402 Kirkness Street, Arcadia, Pretoria, Gauteng Province. I shall refer to the 1st applicant herein as either "**the 1st applicant**" or "**Sakeliga**".

7 The 1st applicant is a business interest organisation with a supporter and donor base of more than 12,000 businesspeople, companies and organisations, and a network of more than 40,000 subscribers in South Africa.

8 The 1st applicant was established in 2011 and was incorporated and registered as a non-profit company in terms of the Companies Act, Act 71 of 2008, in 2012. The 1st applicant's main objective is the protection of constitutional rights, constitutional order, the rule of law, free-market principles, and a just and sustainable business environment within the Republic of South Africa.

9 In seeking to achieve its objectives, the 1st applicant lobbies to promote a free market and economic prosperity to create a favourable business environment in the interest of its supporters and the common good. In order to give effect to its main objective, the 1st applicant also provides support to its supporters and the public at large, which support includes legal support. Further, to achieve its objectives and to perform its functions and mandate, as an ancillary object, the 1st applicant seeks to act in the interest of its supporters and members of the public to protect their businesses and other constitutional rights.

10 What I have set out above is also evident from an extract of the 1st applicant's memorandum of incorporation, a copy of which I attach hereto marked **X2**. I respectfully draw the court's attention to clause 4 of the memorandum of incorporation which sets out in more detail the objects, ancillary objects as well as the powers of the 1st applicant. I request the court to incorporate the content thereof herein as if specifically set out. I do not attach a full copy of the memorandum of incorporation to these papers, because it will make these papers unnecessarily long. Should the court or any of the respondents wish to

have sight of the full memorandum of incorporation, the 1st applicant shall make this available.

The 2nd applicant

11 The 2nd applicant is **AGRI NORTH WEST**, a non-profit member's organisation with a separate legal personality from its members and primary business address at Agri NW Head Office, 5 Swart Street, Lichtenburg, North West Province. I shall refer to the 2nd applicant herein as either **"the 2nd applicant"** or **"Agri NW"**.

12 The 2nd applicant was established in 1995 as a member organisation for agricultural producers in the North West province. It is the 2nd applicant's mission to act as a representative body for members conducting business within agriculture and to ensure the sustainability of the industry.

13 The 2nd applicant comprises various affiliated members (farmers), local and municipal agricultural associations and other affiliated organisations with voting rights at its annual conference. The 2nd applicant is governed by an executive council appointed at its annual conference. The 2nd applicant's constitution expressly authorises the 2nd applicant to institute and participate in any legal proceedings supporting its primary objectives.

14 I attach hereto an affidavit by Mr Boeta Du Toit, the 2nd applicant's chief executive, duly appointed and authorised by its executive council, in support of this application.

The 3rd applicant

15 The 3rd applicant is **TLU SA**, a non-profit national agricultural union with a separate legal personality from its members and with its principal place of business at TLU Building, 194 James Drive, Silverton, Pretoria, Gauteng. I shall refer to the 3rd applicant herein as either "**the 3rd applicant**" or "**TLU SA**".

16 The 3rd applicant was established as a farmers union in 1896, and has since April 2002 operated as a national organisation aimed at promoting the business interests of its members and supporters with a special focus on matters affecting the commercial agricultural industry and the interests of commercial farmers.

17 It is the mandate of the 3rd applicant to act in the public interest and to promote on behalf of its members' issues relating to the independence of the agriculture sector, the economic sustainability of the agriculture sector, food security, property rights, the economy in general and the promotion of free-market principles necessary for commercial agriculture to prosper. Members have mandated the 3rd applicant to participate in litigation to promote and protect the organisation and their interests.

18 The 3rd applicant comprises various local farmer's associations and affiliated trade organisations across South Africa, with a significant representation of members conducting business within Gauteng, Mpumalanga and Limpopo provinces. The 3rd applicant is governed by an executive committee appointed annually by its national congress.

19 I attach hereto an affidavit by Mr Gabriel Jacobus Lötter, the 3rd applicant's head of services and trauma, duly appointed and authorised by its executive committee, in support of this application.

The 4th applicant

20 The 4th applicant is **MAGALIESBERG CITRUS COMPANY (PTY) LTD** a private company duly registered in terms of the company laws of South Africa with primary business address at Portion 1160, Farm Hartbeestpoort B410JQ, Kareepoort, North West Province.

21 The 4th applicant was established as a pack house for fresh fruit (then known as Magaliesberg Citrus Co-operative Ltd) in 1959. It has since grown to become one of South Africa's leading citrus processing plants.

22 The 4th applicant has approximately 90 citrus farmer shareholders who deliver about 60 000 tonnes of citrus fruit for processing by the 4th applicant every year. The 4th applicant, amongst other things, produces and supplies about 75 million litres of ready-to-drink fruit juices and concentrates for domestic market consumption.

23 I attach hereto an affidavit by Hans du Preez, the Chief Executive Officer of the 4th applicant, duly appointed and authorised by the company board of directors, in support of the application.

THE RESPONDENTS

24 The 1st respondent is **ESKOM SOC LTD**, a state-owned company incorporated in accordance with the relevant laws of the Republic of South Africa with

registered address at Megawatt Park, Maxwell Drive, Sunninghill, Sandton, Johannesburg, Gauteng. I shall refer to the aforesaid respondent as the "**1st respondent**".

25 The 2nd respondent is the **NATIONAL ENERGY REGULATOR OF SOUTH AFRICA (NERSA)**, a national regulatory authority established as a juristic person in terms of section 3 of the National Energy Regulator Act 40 of 2004, with offices situated at Kulawula House, 526 Madiba Street, Pretoria, Gauteng. The 2nd respondent is the regulatory authority for the electricity industry in terms of the Electricity Regulation Act 4 of 2006 ("**ERA**").

26 The 3rd respondent is the **MINISTER OF MINERAL RESOURCES AND ENERGY OF SOUTH AFRICA**, currently, Mr Samson Gwede Mantashe, cited herein in his nominative capacity. I shall refer to the aforesaid respondent as the "**3rd respondent**" or "**the Minister**". The Minister is the head of the National Department of Mineral Resources and Energy, with offices situated at Trevenna Campus, Building 2C, corner of Meintjes and Francis Baard Street, Pretoria, Gauteng.

27 The 2nd and 3rd respondents have been joined because of their potential interest in the outcome of this application. No cost order is sought against the aforesaid respondents unless any one of them opposes the present application.

28 A copy of these papers will also be served on the State Attorney Pretoria.

PURPOSE OF THE APPLICATION

29 In this application, the applicants seek the review and setting aside the policy and decisions of the 1st respondent to apply periodic and/or scheduled and/or *ad*

hoc load reduction to so-called high-loss feeder lines alternatively to feeder lines where the 1st respondent is experiencing high electricity use losses (the "**load reduction policy**").

30 The applicant seeks the reviewing and setting aside of the load reduction policy in as far as it unlawfully differentiates, targets, and penalises paying direct (also sometimes referred to as "stand-alone") customers and end-users that reside and/or conduct business on so-called high-loss feeder lines across the country. It does deal with the rights of municipal electricity users.

31 Only the 1st respondent is directly affected by the relief sought in the notice of motion.

32 The applicants submit that on the information available to them, without the benefit of having regard to the 1st respondent's record, clear grounds for the review and setting aside of the 1st respondent's load reduction policy exists. However, after receipt of the 1st respondent's record, the applicants will be better placed to deal more fully with the matter. The applicants have been advised then submit that they have the right in terms of the rules of court once all relevant records have been disclosed in terms of Uniform Rule 53, to supplement these papers and to amend the relief sought in the notice of motion.

LOCUS STANDI OF THE APPLICANTS

33 The 1st to 3rd applicants:

33.1 Bring this application by virtue of section 38 (a) of the Constitution, acting in their own interest in accordance with their respective objectives.

33.2 Also bring the application in the interest of a group or class of persons in terms of section 38(c) of the Constitution, specifically their respective supporters and members affected by the load reduction policy and action of the 1st respondents as discussed in this affidavit.

33.3 Furthermore, the 1st to 3rd applicants also bring this application in the public interest in terms of section 38 (d) of the Constitution, on behalf of all direct customers and end-users of electricity who are directly affected by the load reduction policy and action of the 1st respondent as discussed below.

34 The 4th applicant brings this application in its own interest as a consumer of electricity and as a direct customer of the 1st respondent being affected by the decision and action of the 1st respondent as discussed in this affidavit below. The 4th applicant also brings this application in the general public interest on similar grounds as set out in 33.3 above.

35 The subject matter of this application and the load reduction policy and action on direct customers and end-users of electricity supplied by the 1st respondent engage various rights and obligations, including constitutional rights and obligations, which stand to be infringed and/or affected.

36 These direct consumers and/or end-users affected by the load reduction policy and action of the 1st respondent include various businesses that fall outside of the current supply areas of municipalities and in the so-called legacy supply areas of the 1st respondent. These consumers depend on the rendering of basic electricity supply by the 1st respondent. The supporters of the 1st to 3rd applicants, such as the 4th applicant, pay for their electricity services. Despite being paying

customers of the 1st respondent, they are being deprived and/or stand to be deprived of this basic service through the interruption or disconnection of electricity supply to their feeder lines under the auspices of the 1st respondent's load reduction policy. These businesses and individuals have suffered and are likely to suffer, alternatively, be severely financially prejudiced in their business operations, by the 1st respondent's load reduction policy and action.

37 The subject matter of this application involves the broader public interest as a result of the 1st respondent's public duty to supply, distribute and reticulate electricity to its customers and end-users, especially in areas where municipalities are not supplying such services. This matter engages various direct and consequential constitutional and public interest considerations.

38 The 1st applicant has various members across the Republic of South Africa who conduct businesses in areas affected by the 1st respondent's load reduction policy and decisions. Most of the 1st applicant's supporters in the affected areas include small businesses that cannot generate their own electricity and are completely reliant on the supply of electricity by the 1st respondent. The 2nd and 3rd applicants represent the interest of production and commercial farmers, who are equally prejudiced by the lack of electricity supply to their farming operations.

39 The 1st applicant also acts in the interest of larger businesses that are, as a consequence of the load reduction policy and action of the 1st respondent, required to incur massive costs in order to remain profitable. The 4th applicant is such a business.

40 The 4th applicant, who is also a supporter member of the 1st applicant, brings this application in its own interest. The 4th applicant is a food processing operation

that is dependent on the supply of electricity to its processing plants in the North West province. The 4th applicant is a direct customer of the 1st respondent and uses electricity, especially in the processing of citrus fruit, the refrigeration and storing of fruit concentrates, as well as other value added production processes in order to supply local and international markets with perishable food products. The 4th applicant uses critical operational equipment in the course of its business, such as its processing, packaging and especially refrigeration units. All of them rely on electricity to operate. Notwithstanding production losses suffered when production breaks down during load reduction, the 4th applicant must incur significant expenses to generate its own electricity to maintain a minimum temperature in its cooling and refrigeration plants.

41 As will be shown later in these papers, businesses such as the 4th applicant are seriously affected by persisting load reduction being applied by the 1st respondent to the Modderspruit-Molokwe feeder line connecting to the 4th applicant's main production site (see annexure **X3**).

42 Load reduction affects not only the applicants and the businesses they represent but also other interest of other natural persons who reside in areas affected by persistent load reduction.

43 The applicants' *locus standi* is further evidenced and explained in the paragraphs to follow.

SALIENT FEATURES OF THE APPLICATION

44 The applicants seek final relief against the 1st respondent. The Honourable Court also has the power to grant a just and equitable remedy in terms of section

172(1)(b) of the Constitution and in terms of section 8(1) of the Promotion of Administrative Justice Act 2 of 2000 ('PAJA').

45 This application concerns the policy and action of the 1st respondent concerning a practice known as "load reduction". The 1st respondent has persistently implemented so-called load reduction since at least June 2020, to the effect of completely curtailing the power supply on selected electricity feeder lines in the country for hours on end. Load reduction is implemented regardless of and on top of the infamous "load shedding" in South Africa.

46 The subjection of lines to load reduction occurs to the considerable detriment of direct consumers and end-users, particularly paying end-users, of electricity.

47 While the 1st respondent has not taken the public in its confidence regarding the issue and has not been transparent, it appears from high-level explanations in media statements of the 1st respondent that load reduction is used as a measure to combat the 1st respondent's apparent failure and inability to effectively manage, maintain and police its own feeder lines.

48 From correspondence with the 2nd applicant, it also appears that the 1st respondent is using load reduction for the ulterior motive of effecting debt collection on select feeder lines.

49 As a result, paying end-users on affected feeder lines are also subjected to load reduction. This causes severe hardship to many direct consumers and end-users of electricity across the country because the 1st respondent effectively has a statutory monopoly on electricity supply to customers falling outside of the supply network of other licensees, such as municipalities.

50 The detriment is exacerbated by the fact that the 1st respondent followed no proper notice or consultation processes before implementing its load reduction policy to areas where it has lost control of the administration and management of feeder lines.

51 The applicants will show that the policy of load reduction and the conduct of the 1st respondent in continuing to interrupt the supply of electricity to paying direct customers under the guise of so-called load reduction is unlawful, unconstitutional and *ultra vires* the empowering legislation. Therefore, the 1st respondent's load reduction policy stands to be reviewed and set aside, alternatively declared unconstitutional. These submissions will be developed further on receipt of the 1st respondent's rule 53 record.

CONSTITUTIONAL ISSUES

52 The policy of load reduction and its implementation raises important and fundamental constitutional and legislative issues. This is because direct customers are being penalised for the failure of the 1st respondent to properly audit and manage its distribution and reticulation networks across the country.

53 Law-abiding citizens, direct consumers and end-users of electricity who diligently settle or attempt to settle their direct supply electricity accounts with the 1st respondent, find themselves in the untenable situation that notwithstanding compliance with their obligations towards the 1st respondent, they are severely prejudiced and affected by a continued process of power cuts above and beyond national loadshedding. Further, they are vulnerable to their statutory dependency on the provision of electricity by the 1st respondent and cannot seek alternatives in other suppliers.

54 In essence load reduction adversely impacts on paying direct customers' Constitutional rights to be provided with basic electricity services, to equality under the law (section 9), to have one's dignity respected (section 10), the practice of trading occupation or profession (section 22), housing and property (section 25 and 26), healthcare services (section 27), water and education (section 29(1)).

55 In addition, as will be shown in this application, the 1st respondent would only provide short and irregular notices to the affected public of its intention to effect load reduction in specific areas via its communication platforms and social media such as its Twitter page. However, as will be shown in these papers, most people who are affected by the load reduction policy and action of the 1st respondent are unaware that it is indeed more than national load-shedding coupled with breakdowns on the line. Even though interruption is irregular and temporary, the process has become a regular feature in the lives of customers and end-users who receive direct electricity supply from the 1st respondent. This infringes on direct customers and end-users' right to just administrative action.

56 The applicants expect to show on the filing of their supplementary affidavit on receipt of the 1st respondent's rule 53 record, that there is no rational or reasonable basis for load reduction as it is being implemented by the 1st respondent. The applicants have been advised that the 1st respondent's purported reasons for implementing load reduction, i.e. to prevent against network overload as a result of illegal connections and misuse and to recover debt, is irrational, unreasonable and also exposes an ulterior purpose of

collecting electricity charges from non-paying customers to the detriment of paying direct customers and other lawful end-users.

57 The 1st respondent's conduct has also failed to consider alternative measures which would limit the damage to paying direct customers.

58 It will also be shown that the impugned policy and conduct violate the legality principle and the rule of law for reasons stated further herein.

59 In the premises, the 1st respondent's load reduction policy and implementation of load reduction stand to be reviewed and set aside.

60 In support of these arguments, the applicants intend to provide the necessary further evidence once they have had an opportunity to consider the 1st respondent's records and reasons for the load reduction policy and their conduct.

LEGISLATIVE ISSUES

61 As will be shown in this application, the complete curtailment of electricity supply to paying direct customers under the circumstances present when load reduction is implemented is expressly prohibited by the ERA. In particular:

61.1 The ERA provides that the 1st respondent, as a licensee under the ERA, may not discriminate between customers or classes of customers regarding access, tariffs, prices and conditions of service, except for objectively justifiable and identifiable differences approved by the 2nd respondent.

61.2 The 1st respondent may not reduce or terminate the supply of electricity to a direct customer, except for in specific circumstances set out in the ERA, which the applicants will argue herein, are not present.

62 When the 1st respondents implement load reduction, they are in breach of their license obligations under the ERA.

OTHER POLICY INTERVENTIONS AIMED AT PREVENTING LOSSES

63 In its *Multi-Year Price Determination (MYPD) 5 Revenue Application for FY 2023 – FY 25 (June 2021)* as submitted to the 2nd respondent (a relevant extract of which is attached hereto as annexure **X4**), the 1st respondent confirmed:

63.1 that it is currently providing electricity to 6.7 million customers as part of its distribution network, where the focus is on sales, revenue collection and customer service (page 11 of the document);

63.2 that of all of the customers serviced directly by the 1st respondent, 84% of its total annual income is generated from supply to municipalities, industrial and mining customers. Even though residential customers receiving electricity directly from the 1st respondent make up 98% of the total number of customers, only about 6% of total sales volume is generated by this segment. The remaining 10% of local sales volume is generated by a small number of redistributive, commercial entities, rail and agriculture businesses (I refer to Figure A1 below, taken from page 11 of the document).

TABLE 6: NUMBER OF ESKOM CUSTOMERS

Customer Category	Actual FY2017	Actual FY2018	Actual FY2019	Actual FY2020	Projection FY2021	Growth to date
Redistributors	802	800	800	805	804	-1
Residential	5 838 754	6 120 122	6 358 523	6 577 905	6 720 150	142 245
Commercial	50 956	51 848	52 556	52 909	52 880	-29
Industrial	2 706	2 703	2 705	2 684	2 649	-35
Mining	1 012	993	981	961	945	-16
Agriculture	81 806	81 638	81 303	80 451	79 115	-1 336
Rail	510	501	493	475	475	0
Local Customers	**5 974 546**	**6 258 605**	**6 497 361**	**6 716 190**	**6 857 018**	**140 828**

Figure A1

63.3 that the 1st respondent uses energy balancing (the reconciliation of electricity delivered and sold between two feeder lines), in order to prioritise high-loss feeder lines for so-called *normalisation* (page 12 of the document).

63.4 that energy losses are managed by means of various interventions aimed at addressing losses from a technical, commercial and social perspective (page 31 of the document). These interventions include:

63.4.1 reconciliation of the energy delivered and energy sold at feeder line level;

63.4.2 auditing and repairing of faulty customer meter installations;

63.4.3 disconnection of illegal connections, metered dampers and imposition of penalties;

63.4.4 investigations and subsequent prosecution of electricity theft and electricity criminal syndicates.

64 None of the interventions listed above contemplates load reduction in the manner being employed by the 1st respondent.

65 In contrast to policies that may be rational concerning the recovering of debt, load reduction as a debt collection mechanism merely exacerbates a growing financial crisis within the 1st respondent with an adverse knock-on effect on citizens, businesses, the local economies within which these businesses operate, and the country's broader economy.

66 The applicants will also show that even if it is found that the ERA allows for load reduction as is currently being implemented by the 1st respondent, the circumstances under which the power is exercised do not provide a valid ground for the implementation of load reduction to selected feeder lines.

BACKGROUND TO APPLICATION

67 During or about June 2022, the 1st applicant started receiving complaints from supporters from across the country, especially the North West and Limpopo provinces, about the implementation of an extraordinary form of 'load shedding' being enforced by the 1st respondent in respect of customers and end-users that connect directly to its national grid. It was and is still being reported that these businesses and residents are subjected to 'load shedding' over and above and for longer periods than published by the 1st respondent as part of its national emergency load shedding schedules (**"national load shedding"**).

68 During this period, the 2nd applicant also approached the 1st applicant regarding the issue of a load reduction policy being applied in respect of so-called high-loss feeder lines.

69 The 2nd applicant had received similar complaints from its members and had been investigating the issue since approximately April 2022. At that stage, the 2nd applicant was investigating the implementation of load reduction and national load shedding over two feeder lines in the North West Province, known as the Mimosa and Pella feeder lines.

70 As part of its investigation, the 2nd applicant attempted to engage with the 1st respondent regarding the issue of load reductions being applied over the Mimosa and Pella feeder lines. A meeting was held on 25 April 2022 with representatives of the 1st respondent's North West management team, which included Ms Ntidiseng Makgamatha ("Makgamatha"), a so-called middle manager of the 1st respondent's customer relations team.

71 A short string of e-mail correspondence between Makgamatha and Mr Naude Pienaar ("Pienaar"), the general manager of the 2nd applicant, followed the interaction. A copy of the correspondence over the period of 26 April 2022 to 20 June 2022 is attached hereto as annexure **X5**.

72 The e-mail string includes an e-mail sent on behalf of Pienaar on 26 April 2022 in which Pienaar confirms the headnotes of the meeting held on 25 April 2022. The following portion is relevant to this application:

> *"Whilst understanding **the challenges Eskom has with losses, lack of capacity, shortage of staff and equipment, we also appreciate your agreement and understanding that paying customers should not be in a position where they are losing a lot of income because of load reduction.***
>
> *We also appreciate **your proposal that the Eskom team will propose a workable solution to complete audits on the specific***

> ***lines** in order for Eskom to make better informed decisions. Agri NW will support such a process and will communicate this to our structures.*
>
> *We would also like to **request that load reduction on these two lines will be stopped immediately, pending the outcome of the audits and the subsequent arrangements with affected customers**. This will alleviate the very high frustration levels of complying customers and might lessen the propability* (sic) *of expensive legal steps currently being considered by some customers.*
>
> *Hope to hear from you soon."* [own emphases]

73 According to Pienaar, the 1st respondent at the meeting of 25 April 2022 confirmed that they were applying load reduction to at least 62 feeder lines where they suffered high losses ostensibly due to illegal connections and poor recovery. The 1st respondent did not divulge in which provinces and districts the targeted feeder lines were.

74 According to the 1st respondent, the policy of load reduction was applied as part of a clampdown on illegal connections and a general under-recovery of monies owed by electricity users in predominantly rural areas. It was mentioned during the meeting that the primary feature in the poor recovery was obsolete and dysfunctional electricity meters on farms and smallholdings and a shortage of staff to oversee meter readings, maintenance and the management of illegal connections on the line.

75 Importantly, the 1st respondent at the meeting undertook:

75.1 to conduct a line audit in order to assess the scope of the problem.

75.2 to revert to the 2nd applicant with a 'workable solution' which would allow for the lifting of load reduction in respect of paying customers.

76 In return, the 2nd applicant undertook to support any reasonable proposal which would result in a curtailment of the damages being suffered by its members on the two feeder lines who require electricity to conduct their primarily agricultural businesses effectively.

77 On 6 May 2022, Makgamatha provided Pienaar with the following response:

> *"Your proposal was presented to the Operating Unit leadership and unfortunately Eskom is unable to suspend the load reduction.*
>
> ***The principles applied for load reduction are that we complete the interventions, which is to audit the feeder, monitor that losses are reduced to acceptable level and then load reduction can be uplifted.**" [own emphasis]*

78 The statement above clearly confirms the existence of a load reduction policy applied by the 1st respondent in respect of so-called high-loss feeder lines.

79 Unlike national load shedding, the aim of load reduction on a high-loss feeder line is not to respond to shortages in the generation of electricity on the side of the 1st respondent but rather to respond to losses suffered as a result of illegal electricity usage on the line.

80 While national load shedding is applied on a rotational basis with relatively equal impact to all electricity users across the country in terms of a published load shedding schedule, the load reduction policy is only applicable to feeder lines where the 1st respondent assesses to experience 'unacceptable' losses. What

the exact criteria are against which so-called acceptable and unacceptable loss levels are measured remains unclear to the applicants.

81 To date of this affidavit and despite a letter of demand on 1 August 2022 referred to hereinbelow, the 1^{st} respondent is yet, despite an undertaking to do so on 25 April 2022, to provide feedback on an audit of the Mimosa and Pella feeder lines or the possibility of a workable solution which would at least allow paying customers on those lines predictable and sustainable access to electricity.

82 According to Pienaar, the 2^{nd} applicant can report that load reduction is still being applied to the Mimosa (as recent as November 2022) and Pella (as recent as October 2022) feeder lines. None of the 2^{nd} applicant's members on the two lines are aware of an audit being conducted. No interventions by the 2^{nd} applicant on the two lines have been observed or communicated to residents to date of this affidavit.

83 On 20 June 2022, Pienaar again directed an e-mail to Makgamatha requesting feedback about the results of the 1^{st} respondent's audit of the lines. Pienaar also requested that the 1^{st} respondent terminate load reduction at least until the results of the line audit were available. I refer in this regard to the confirmatory affidavit by Pienaar and affected customers confirming the above.

84 During June 2022 to July 2022, the 1^{st} and 2^{nd} applicants, realising that the 1^{st} respondent's load reduction policy was not merely a temporary measure only being applied to the Mimosa and Pella feeder lines, started to enquire within their broader supporter bases whether load reduction was being enforced in other areas across the country. The 1^{st} and 2^{nd} applicants contacted other agricultural

organisations with footprints in provinces outside of the North West, including the 3rd applicant.

85 The 3rd applicant confirmed that its members in the Limpopo province had also complained about discriminatory load reduction being applied to selected feeder lines across the province, resulting in substantial production interruptions and losses on commercial farms and other rural businesses.

86 By the end of July 2022, the 1st to 3rd applicants had received evidence of regular and persistent load reduction being applied to the following feeder lines across the North West and Limpopo provinces:

86.1 North West – Mimosa feeder line

86.2 North West – Pella feeder line;

86.3 Limpopo – ST 2021 feeder line;

86.4 Limpopo – ST 2022 feeder line;

86.5 Limpopo – Sanria Rural / Tuinplaas feeder line;

86.6 Limpopo – SLG 2022 feeder line;

86.7 Limpopo – SGP 2021 feeder line;

86.8 Limpopo – Soutpan/Ingwe feeder lines;

86.9 Limpopo – Zebra feeder lines;

86.10 Limpopo – Levubu K feeder lines;

86.11 Limpopo – Mulendane / Tshakuma feeder line;

86.12 Limpopo – Lephalale TST feeder line;

86.13 Limpopo – Villa Nora / Rural Marken feeder line.

87 Was it not for the efforts of the 1st to 3rd applicants to gather evidence on the policy and implementation of load reduction, they would today still be completely in the dark as to the extent of the underlying problems that the 1st respondent purportedly relied on in subjecting lines to load reduction. Despite the best efforts of the 1st to 3rd applicants to gather more information on the full load reduction policy, reasons for it and extent of the problem are however still not known.

88 Consequently, the 1st to 3rd applicants instructed KWV to direct a letter of demand to the 1st respondent and further investigate the matter.

89 On 1 August 2022, KWV directed a letter to the 1st respondent in which the 1st to 3rd applicants:

89.1 requested confirmation that direct customers on the feeder lines mentioned in paragraph 86 above were being subjected to load reduction over and above national load shedding;

89.2 recorded that the *"introduction of these additional outages coincided with Eskom's announcement that it would implement load reduction in six provinces, ostensibly to avoid overloading the network and resulting damage to infrastructure in "high-density areas that are prone to network overloading"".*

89.3 referred to the meetings and correspondence discussed in paragraphs 70 to 86 above and the lack of a proper response from the 1st respondent

89.4 recorded that the only reasonable conclusion which the 1st to 3rd applicants could make was that:

> *"16.1 Eskom is imposing targeted black-outs on its direct customers under the guise of load reduction;*
>
> *16.2 Eskom is thereby acting in breach of the Electricity Regulation Act 4 of 2006; and*
>
> *16.3 Eskom is thereby prejudicing:*
>
> *16.3.1 the ability of its direct customers to conduct their businesses, especially in the farming and related agricultural sectors;*
>
> *16.3.2 electric equipment and infrastructure on the affected businesses and farms, utilised in the affected direct customers' conduct of their businesses, which is damaged or at risk of damage by unannounced blackouts;*
>
> *16.3.3 the profitability of affected businesses, and in turn puts at risk thousands of employment opportunities in the affected areas;*
>
> *16.3.4 the food security of the Republic of South Africa, which is reliant on the ability of its direct customers to conduct their businesses in the farming and related agricultural sectors; and*
>
> *16.3.5 the safety and securing of all persons residing on or otherwise present on the affected farms during targeted black-outs on its direct customers, implemented under the guise of load reduction.*
>
> *17. These prejudicial impacts have been exacerbated by the recent escalation of the national program of load-shedding, which sees Eskom implement levels 4 and 6 loadshedding on impractically short notice to customers."*

89.5 requested the parties seek an amicable long-term solution to the problem.

90 A copy of the letter and proof of transmission are attached hereto as annexures **X6** and **X7**. I should pause to mention that paragraphs 6, 8 and 20.2 of the letter mistakenly refer to "section 5.7.1 Electricity Regulation Act 4 of 2006" instead of "paragraph 5.7.1 of the NRS048-2". The relevance of the NRS048-2 will be discussed below.

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA

91 The 1st respondent has to date not responded to KWV's letter.

INADEQUATE NOTICE

92 As far as the applicants at the time of this affidavit could determine, media outlets as far back as June 2020 started reporting on a decision taken by the 1st respondent to implement “load reduction” across various provinces, including Gauteng, Free State, KwaZulu-Natal, North West, Limpopo and the Northern Cape.

93 On 30 June 2020, *Business Insider* reported that the 1st respondent would start implementing load reduction in addition to load shedding. A copy of the media report is attached hereto as annexure **X8.** According to *Business Insider*:

93.1 whereas **national load shedding** would be applied when South Africa "*does not have enough capacity to generate electricity, and the country is hit by scheduled, controlled blackout across different areas*", **load reduction** would be introduced "*in neighbourhoods where illegal connections cause overload and damage into infrastructure*" and would result power being "*switched off*".

93.2 according to the media report, load reduction would be implemented for the following reasons:

93.2.1 "Eskom spokesperson Sikonathi Mantshantsha says the increase of illegal connections in high density areas in the province and the growing number of backyard dwellings connecting to a single house are overloading neighbourhood electricity systems."

93.2.2 "Once the transformer is overloaded, it then explodes and that whole area will not have electricity," said Mantshantsha."

93.2.3 "[We] will not be fixing that infrastructure until we have resolved the problem that's illegal connections, until the people agree to pay for the electricity in those areas."

93.2.4 "It is also now switching off power when it sees signs of illegal power use."

93.2.5 "Eskom has decided that whenever we notice a surge in demand in that area beyond what the network is designed for, to switch off in order to protect infrastructure, so we call that load reduction," said Mantshantsha. "

94 Since 2020, the 1st respondent would announce the implementation of load reduction from time to time via social media and its various communication apps. Most of the notifications considered by myself, were sourced from the 1st respondent's official Twitter page (handle @*Eskom_SA*) (the "Twitter page").

95 Attaching every reduction notice published on the Twitter page would be impractical, as hundreds of these notices have been issued since 2020. However, I have studied the notices on the Twitter page from June 2020 until October 2022. Most of these notices follow a standard format, depending on the template used by the different regional managements of the 1st respondent responsible for issuing the notice. Most of the load reduction notices include statements to the effect that:

95.1 the 1st respondent needs to implement load reduction to "*avoid overburdening the Eskom network and causing infrastructure damage in high-density areas prone to network overloading*". I attach in this regard copies of notices published on 26 November 2021 (annexure **X9**), 24 December 2021 (annexure **X10**), 28 December 2021 (annexure **X11**), 20 January 2022 (annexure **X12**), and 20 February 2022 (annexure **X13**). The notices also include a statement that communities "*are encouraged to report meter bypasses, illegal connections and vandalism of electricity infrastructure*."

95.2 the 1st respondent needs to implement load reduction to "*prevent network overloading in high-density areas*" and that "*overloading of networks leads to damage to the electricity infrastructure through explosions in overloaded transformers and mini substations. It also poses danger to people and property in affected communities. Currently, Eskom is battling to keep up with the increased equipment failure that is costing millions to repair.*" The notices also warn: "*Eskom urges customers to treat all installations as live. Customers are advised to report any illegal activities* *on Eskom lines*". I attach in this regard copies of a notice published on 27 August 2022 (<u>annexure</u> **X14**)

96 I should note at this stage that, even though the 1st respondent would often publish notices on its social media accounts and its Twitter page, many consumers affected by the load reduction policy were:

96.1 unaware of the fact that they were being subjected load reduction, as opposed to national load shedding;

96.2 wholly unaware of the underlying financial and debt collection motivations behind load reduction;

96.3 under the impression that load reduction, where they did not confuse it with load shedding, was caused by systems and infrastructure failure in their area.

97 Most businesses, such as the 4th applicant, only started to realise that they were being subjected to extraordinary load reduction measures during or after November 2021, when the 1st respondent started to ramp up its action under the policy.

98 Due to the total lack of transparency on the issue, very few people have knowledge about the true reasons underlying the 1st respondent's conduct. In fact, the applicants have only sufficiently come to grips with the extent of the issue after instructing KWV to assist them with the finalisation of these papers, and obtaining advice on the relevant statutory and regulatory provisions relating to the issue of load reduction during September 2022 to November 2022.

99 The section to follow will briefly deal with the relevant legal position.

RELEVANT STATUTORY AND CONSTITUTIONAL PROVISIONS

Duty to supply electricity

100 The statutory and constitutional provisions referred to further herein are not exhaustive, and the applicants reserve the right to deal with such statutory and constitutional provisions more comprehensively during argument.

101 Section 41 (1) of the Constitution provides that all spheres of government and all organs of state must inter alia, secure the well-being of the people of the Republic. This provision enjoins the 1st respondent, which is tasked with the distribution and reticulation of electricity – one of the most common and most important basic public services.

102 The services provided by the 1st respondent have become virtually indispensable for the well-being of modern society. They are particularly indispensable for *inter alia* the exercising of a trade and occupation, a healthy environment, adequate housing, access to water and access to education.

103 The 1st respondent was specifically established to meet the electricity needs of South Africa. It is mandated and enabled to supply electricity.

104 The 1st respondent bears a public duty to generate, distribute and in certain cases also reticulate electricity to customers and end-users. It stands in a particular relationship towards direct customers and end-users.

105 The distribution and supply of electricity are primarily, though not exclusively, a constitutional function of local government. Historically, it has been impractical,

expensive and factually impossible for municipalities to oversee and manage the distribution, reticulation and supply of electricity in rural areas falling outside the available infrastructure networks of municipal towns. Not all areas of the country fell within a municipal supply network, necessitating direct supply by Eskom to many customers and end-users that still persists today.

106 The 1st respondent is factually and also in law under a constitutional public duty to supply and reticulate electricity directly to individuals and businesses, especially those falling outside of the licensed area of supply of a municipality.

Nersa license requirements

107 In terms of the 2nd respondent's *Nersa Rules for Licensable Distribution Areas of Supply* (published on 29 July 2020) ("Nersa Distribution Rules"), individuals and businesses falling outside of the licensed area of supply of a municipality are deemed to be 'stand-alone customers', which the 2nd respondent defines as:

> *"a customer or an end-user that does not fall within a licensed or licensable area of supply but is connected to the distribution network of a distributor through its High Voltage (HV), Medium Voltage (MV) or Low Voltage (LV) network, and has an individual metered point of supply (PoS)."*

108 The 2nd respondent also foresees that the legacy system in terms of which the 1st respondent will continue to supply electricity to stand-alone customers, will continue. Rule 6.2.1 of the Nersa Distribution Rules requires that:

> *"Where it is evident and practically feasible that another distribution licensee is demonstrably best placed to supply a new area of supply, a reseller or a stand-alone customer (not yet connected), the*

licensees shall cooperate to ensure the best solution from a country perspective."

109 These Rules are bolstered by the provisions of the ERA, which provides for the regulation of the supply of electricity across the Republic and the establishment and functions of Nersa as the energy regulator. The ERA seeks to regulate efficient, effective, sustainable and orderly electricity supply (section 2 (a)).

110 Section 2 (b) provides that it is one of the objects of the ERA to ensure that the interests and needs of both present and future electricity customers and end-users are protected and met. It also seeks to strike a fair balance between the interests of customers, end-users, licensees, and investors in the electricity supply industry and the public (section 2 (g)).

111 The 2nd respondent is the independent body created as the custodian and enforcer of the regulatory framework provided for in the ERA. The ERA regulates the issuing of licences and the operation, generation, transmission, and distribution of electricity. It is the function of the 2nd respondent to give effect to the relevant provisions.

112 Section 21 (2) of the ERA provides that the 1st respondent, as a licensee under the ERA, may not discriminate between customers or classes of customers regarding access, tariffs, prices and conditions of service, except for objectively justifiable and identifiable differences approved by the 2nd respondent.

113 Section 21 (5) of the ERA, provides that the 1st respondent **<u>may not reduce or terminate</u>** the supply of electricity to a customer, unless:-

113.1 the customers are insolvent;

113.2 the customers failed to honour, or refused to enter into, an agreement for the supply of electricity; or

113.3 the customer has contravened the payment conditions of the 1st respondent.

114 The 1st respondent is a licensed distributor of electricity to customers, which include municipalities. As explained above, the 1st respondent's customers, also include direct end-users, such as the stand-alone customers referred to in the Nersa Distribution Rules.

115 Beyond merely possessing a license to distribute electricity to customers, the 1st respondent currently has a statutory monopoly in respect of the general generation and transmission of electricity in most parts of South Africa. It currently holds three licences issued by the 2nd respondent in respect of conducting its core business, being generation, transmission and distribution.

116 As far as the applicants could glean from the 2nd respondent's website, the 1st respondent is the holder of a NERSA *Licence for the operation of National Transmission Network* (NERSA/ESKOM/TX/698-1301) (attached hereto as annexure **X15**) ("Transmission Licence"). In terms of the Transmission Licence, the 1st respondent:

116.1 is obligated to conduct its business in a fair and reasonable manner (page 3 of Transmission Licence);

116.2 is obligated to make an offer to connect on to its transmission network to *"a person which is, or intends to become, a customer taking supply directly from [the 1st respondent's] transmission network subject to",* *"[r]eceiving a request to do so with all the necessary information", "[t]he customer's ability to pay for the service requested" and "relevant technical estates to be determined through consultation with such person(s)"* (paragraph 4.1.3, page 4 of the Transmission Licence);

116.3 must ensure non-discriminatory access to users of its transmission systems (paragraph 4.2.3, page 5 of the Transmission Licence).

117 In terms of the Transmission Licence, all electricity lines and substation equipment with a nominal voltage below 132 kV, will form part of a distribution system (or classified as transmission transformation equipment) (page 11 of the Transmission Licence).

118 The 1st respondent has also been granted a *Temporary Distribution Licence* (NER/D//ESK) by the 2nd respondent, which licence has been continuously renewed and amended by the parties since being granted ("Distribution Licence"). The latest copy, as made available on the 2nd respondent's as website is attached hereto as <u>annexure</u> **X16**. In terms of the Distribution Licence, the 1st respondent:

118.1 is licensed to distribute and supply electricity to all electricity consumers within the areas designated in the schedules of the Distribution License (paragraph 2 of the Distribution Licence) (the schedules have been updated and amended from time to time. Unfortunately, at the time of the signing of this affidavit, not all the schedules have been published on the 2nd respondent's website));

118.2 must ensure that all supply under the Distribution Licence is done in terms of the conditions of licence read together with the Grid Code as approved and amended by the 2nd respondent from time to time (paragraphs 2 and 5.1.2 of the Distribution Licence);

118.3 is under a duty to supply electricity to every person who is in a position to make satisfactory arrangements for payment (paragraphs 4.1 and 5.1.1 of the Distribution Licence);

118.4 may only deviate from the Grid Code where an exemption or derogation has been approved by the 2nd respondent (paragraph 5.1.2 of the Distribution Licence);

118.5 shall not reduce or discontinue the supply of electricity to a consumer unless the consumer is insolvent or the consumer has failed to pay the agreed charges or to comply with the conditions of supply and has failed to remedy the default within 14 days after receiving from the 1st respondent a written notice by post calling upon him to do so (paragraph 5.1.3 of the Distribution Licence);

118.6 shall comply with the 2nd respondent's quality standards for electricity supply, as may be prescribed from time to time, which includes service standards (NRS047) ("Service Code") and quality standards (NRS048) ("Quality Code") as published by the 2nd respondent (paragraph 5.3.1 of the Distribution Licence);

118.7 shall prepare and adhere to plans which protect customers and ensure the effectiveness of the industry, such as those created in terms of the

Service Code and Quality Code (paragraph 5.3.2 of the Distribution Licence);

118.8 shall ensure that metering, billing and revenue collection are effective, efficient and accurate (paragraph 5.3.4 of the Distribution Licence);

Distribution System Operating Code

119 According to clause 8 of the 2nd respondent's *Distribution System Operating Code* (Version 6.2 of January 2022) ("Distribution Operating Code"), attached as annexure **X17**, the 1st respondent as the holder of a distribution licence, is required to develop and maintain emergency and contingency plans to manage system contingencies and emergencies that affect delivery. These plans are supposed to be developed in consultation with all affected participants to the system. A plan must *inter alia*:

119.1 deal with issues relating to load shedding and forced outages at any specific point of connection and how the 1st respondent plans to restore supply under those circumstances (clause 8.1);

119.2 be reviewed biennially in accordance with changes in network conditions (clause 8.3);

119.3 be verified by audits, onsite inspections and actual tests (clause 8.4);

119.4 must comply with the principles of *minimum impact on customers* (clauses 8.2 and 8.4);

JA

119.5 determine emergency operational limits on its distribution system, which must be periodically updated and made available to system participants (clause 8.7);

119.6 conduct network studies regarding the flow, fault level, stability and resonance of its distribution network in support of its plans (clause 8.8).

120 An interesting feature of the Distribution Operation Code, is the requirement that a distributor, such as the 1st respondent, even under abnormal operating conditions, is obligated to take precautionary measures to prevent network disturbances from spreading and to restore supply to consumers (direct customers and end-users) (clause 9.1).

121 Clause 9.3 of the Distribution Operation Code authorises the disruption of network sections in "the event of a prolonged disturbance resulting from unsuccessful corrective measures undertaken". However, this principle is clearly directed at actual systems disturbances, not financial disturbances caused by unlawful electricity use or the under-recovery of revenue over parts of a feeder line.

122 Even if a true emergency occurs in terms of which "load shedding" may occur, the shedding of load may only be initiated following set procedures prepared by the distributor (clause 9.5).

123 Clause 13.1 of the Distribution Operation Code further provides that each holder of a distribution licence "*shall have a maintenance philosophy against which their maintenance practices and programs are compiled and documented in accordance with NRS082. These documented maintenance programs must be*

auditable". Distributors are also required to keep accurate records of maintenance done for a period of at least 5 years.

124 All of this should be read with the duty placed on the holder of a distribution licence to create contingency plans in terms of which all risk-related outages on a distribution network must be conducted in order to ensure (1) the safety of personnel, (2) security and rating of equipment and most importantly, (3) continuity of supply (clause 18.2).

125 Clause 16 of the Distribution Operation Code is of importance to this application, as it sets the framework in terms of which supply to a customer's supply address may be terminated:

> *"16. Disconnection and Reconnection*
>
> *(1) The Distributor may disconnect supply to the customer's supply address if the customer fails to comply with the written notice of non-compliance issued by the Distributor or any arrangement entered into by the Distributor and the customer which the customer has failed to comply with including non-compliance with the Distributor applicable standards.*
>
> *(2) The Distributor shall have the right to interrupt or disconnect supply if a threat of injury or material damage is anticipated as a result of the malfunctioning of the electrical installation equipment on the Customer's premises or on the Distribution System.*
>
> *(3) The Distributor may disconnect immediately without notice the supply to the customer's supply address if:*
>
> *a. The supply of electricity to a customer is used anywhere else other than at the customer's premises as specified in the connection agreement.*

b. A customer takes at the customer's supply address electricity supplied to another customer.

c. A customer is tampering with or permits tampering with the meter and associated components.

d. A customer allows electricity supply to bypass the meter without the Distributor's consent.

(4) Customer (connected at MV and HV levels) shall give written notice to the Distributors of any intended voluntary disconnection.

(5) The Distributor shall reconnect supply to the customer on request by the customer or retailer on behalf of the customer subject to compliance with the relevant provisions of the Distribution Code and other Distributor applicable standards including the timing of reconnection and any reconnection charge imposed by the Distributor."

NRS048-9:2019

126 The 2nd respondent has also published a special subcode under its Quality Codes to regulate load reduction practices known as the *Quality Supply – Part 9 Code of Practice -Load reduction practices, system restoration practices and critical load and essential load requirements on the power system emergencies (NRS048-9:2019)* ("Load Reduction Code"). A copy of the Load Reduction Code is attached hereto as <u>annexure</u> **X18**.

127 The Load Reduction Code does not authorise or provide for implementing load reduction policies and measures described in this application.

128 Any policy that has not been duly authorised by the 2nd respondent and does not comply with section 21 of the ERA, must be informed by paragraph 5.7.1 of the *Quality Supply - Part 6: Measurement and reporting of medium-voltage network*

interruption performance (NRS048-6:2009) ("Network Performance Code"), that reads as follows:

> *"Customer voluntary and involuntary load reduction events are characterised by the curtailment, partial curtailment, or reduction of customer load magnitude, but no actual interruption of supply occurs."*

129 The applicants are unaware of any justification grounds as set out in section 21 (5) of the ERA, relied upon by the 1st respondent when implementing its extraordinary load reduction policy.

130 Similarly, the applicants are not aware of any exemptions or special permissions granted by the 2nd respondent to the 1st respondent which would allow it to:

130.1 differentiate between paying customers and end-users on a particular feeder line on the one hand, and paying customers and end-users on a neighbouring feeder line on the other hand;

130.2 authorise load reduction as a debtor control, collection or management mechanism;

130.3 authorise the application of load reduction outside of the scope of the current NRS048 codes.

131 The applicants can therefore come to no other conclusion, but there is no legal basis for the load reduction policies and conduct currently being implemented by the 1st respondent.

RULE 53 RECORD

132 In terms of rule 53 of the Uniform Rules, the 1st respondent is required to provide justification for its decisions and to despatch to the registrar of this Court, the record of all materials that the 1st respondent considered when deciding upon its load reduction policy. Because the 1st respondent is an organ of state and the public importance of this application, the 1st respondent is also under a specific duty to explain and provide its reasons for the decision before the applicants are required to file supplementary affidavits. It is not for the applicants to have to figure out what the basis and reasons for the 1st respondent's policy and conduct are in respect of load reduction.

133 For sake of clarity, the applicants seek record and reasons regarding the load reduction policy of the 1st respondent as well as the further action of the 1st respondent in applying load reduction regularly to the feeder lines stated in paragraphs 41 and 86 over the last two years.

134 The applicants are entitled to amend their notice of motion and supplement this founding affidavit once the rule 53 record has been filed.

REVIEW OF ACTION

135 All public power is reviewable under the Constitution. The principle of legality requires that the exercise of public power be both substantively and procedurally rational.

136 The 1st respondent must show that its policies and conduct impugned in this application meet the standard of legality on two grounds:

136.1 that it is rationally connected to a legitimate purpose (substantively rational);

136.2 that it has taken into account all of the relevant material necessary to make a rational decision (procedurally rational).

137 Furthermore, the 1st respondent's decision also amounts to administrative action by an organ of state which adversely affects the rights of persons and has a direct external legal effect.

138 The 1st respondent's decision to effectively utilise load reduction as a debt control mechanism is unconstitutional and unlawful, viewed against the context and purpose of ERA as well as the Distribution Licence conditions and standards set by the 2nd respondent in respect of the distribution of electricity to stand-alone customers and end-users that rely upon the 1st respondent for electricity.

139 The 1st respondent's decision is also reviewable in terms of the Promotion of Administrative Justice Act 3 of 2000 ("PAJA") on *inter alia* the following grounds:

139.1 the 1st respondent has not in terms of the ERA, and specifically section 21(2) thereof, received the approval of the 2nd respondent to apply load reduction as a debt management mechanism over high loss feeder lines, to the detriment of paying stand-alone customers and end-users (section 6 (2) (a) (i) and (ii) read with section 6 (2) (b) of PAJA);

139.2 the 1st respondent has not sought public participation, alternatively meaningful engagement with members of the public, and specifically its customers and end-users residing on or conducting business on targeted feeder lines before making its decision to apply load reduction to those feeder lines, and accordingly the process of making the decision is procedurally unfair (section 6 (2) (c) of PAJA);

139.3 the action of the 1st respondent is materially influenced by an error of law in respect of sections 21 (2) and 21 (5) of the ERA as read with the 2nd respondent's Distribution Licence, Grid Code, Service Code, Quality Code and Load Reduction Code (section 6 (2) (d) of PAJA);

139.4 the 1st respondent's action has not been authorised by sections 21 (2) and 21 (5) of the ERA as read with the 2nd respondent's Distribution Licence, Grid Code, Service Code, Quality Code and Load Reduction Code (section 6 (2) (e) (i) of PAJA).

139.5 in fact, section 21 (5) clearly prohibits the termination of the supply to paying customers (section 6 (2) (e) (i) and section 6 (f) (i) of PAJA);

139.6 the 1st respondent's action has been taken under the guise of load reduction but is, in fact, a strategy to limit energy waste and misuse on certain high loss feeder lines across the country. The action of the 1st respondent has been taken for an ulterior purpose and motive (section 6 (2) (e) (ii) of PAJA);

139.7 the 1st respondent failed to take into consideration:

139.7.1 its own failure to audit its high-loss feeder lines regularly and properly to curb and manage losses and misuse on the affected lines;

139.7.2 its own failure to take regular meter readings and conduct proper invoicing practices to collect revenue on high-loss feeder lines;

139.7.3 its own failure to upgrade and/or install smart meters for it to only target non-paying customers and end-users on high-loss feeder lines, without prejudicing paying customers and end-users on the same line;

(section 6 (2) (e) (iii) of PAJA);

139.8 the 1st respondent's action arbitrarily and capriciously differentiates, in contravention with section 21 (2) of the ERA, between paying customers on high-loss feeder lines and paying customers on surrounding feeder lines that are not subjected to the 1st respondent's unlawful load reduction practices (section 6 (2) (e) (vi) of PAJA);

139.9 the 1st respondent's action contravenes sections 21 (2) and 21 (5) of the ERA as read with the 2nd respondent's Distribution Licence, Grid Code, Service Code, Quality Code and Load Reduction Code, in as far as it:

139.9.1 unlawfully differentiates between paying customers regarding their access and conditions of services offered by the 1st respondent;

139.9.2 differentiates between paying customers without an objectively justifiable and identifiable difference approved by the 2nd respondent;

139.9.3 effects a reduction or termination in the supply of electricity to paying standalone customers and end-users

(section 6 (2) (f) (i) of PAJA);

139.10 the action itself is not rationally connected to the purpose of the empowering provisions of ERA as read with the 2nd respondent's Distribution Licence, Grid Code, Service Code, Quality Code and Load Reduction Code (section 6 (2) (f) (ii) (bb) of PAJA);

139.11 the action is unconstitutional and unlawful in as far as it penalises paying stand-alone customers and end-users on high-loss feeder lines for the failure of third parties who ostensibly illegally access and use electricity on those lines (section 6 (2) (i) of PAJA).

140 On the same grounds as set out in paragraph 139 above, the applicants submit that the 1st respondent's current load reduction policies and conduct:

140.1 has not been informed by legitimate reasons or considerations and is thus constitutionally deficient, arbitrary and capricious;

140.2 has been taken for an ulterior purpose without the necessary justification in law and a legitimate governmental purpose;

140.3 are based on reasons unrelated to the objects of load reduction as approved by the 2nd respondent;

140.4 is *ultra vires* section 21 of the ERA;

140.5 unlawfully differentiates between paying stand-alone customers and end-users that rely upon the 1st respondent to supply them with electricity;

140.6 is substantively unfair;

140.7 has been taken without any legitimate reasons grounded in law;

140.8 is unreasonable;

140.9 has failed to take into consideration less restrictive alternatives.

141 For all of the reasons stated above, the applicants submit that the 1st respondent's action should be reviewed and set aside, and declared unconstitutional, ultra vires, unlawful and invalid.

CONDONATION IN TERMS OF SECTION 9 OF PAJA

142 The applicants are alive to the fact that, because the relief sought in the notice of motion is *inter alia* for the review and setting aside of an administrative decision, and because it has become clear that more than 180 days have transpired since some of the applicants have become aware of the administrative action taken by the 1st respondent, the applicants seek condonation in terms of section 9 of PAJA.

143 One of the grounds for the review of the load reduction policy is the failure of the 1st respondent to adequately inform the applicants of the actual reasons behind load reduction on high-loss feeder lines. For instance, customers who saw the 1st respondent's load reduction notices on the Twitter page would not be aware of the actual motivation behind the load reduction policy being applied. In fact, it has been shown in the application above that the actual financial reason behind

the load reduction policy have been disguised as a system and equipment damage prevention exercise.

144 Owing to lack of transparency and proper communication by the 1st respondent, despite letters and a letter of demand, the applicants had to grapple for many months to pin down what the load reduction policy of the applicant actually entails.

145 The load reduction policy of the 1st respondent has never, as far as the applicants are aware, been formally published or gazetted. In addition, no actual policy that remotely resembles load reduction to the high-loss feeder lines as applied in its current form, could be found after a reasonable search on the respective websites of the 1st and 2nd respondent.

146 This application is of national importance as it affects a large section of the population. Affected persons do not have the option of choosing a new supplier of electricity. They are, not because of their own actions, reliant on the 1st respondent and the effects of its administrative decisions. The application is clearly in the interests of justice.

147 For these reasons, the applicants request the Honourable Court to grant condonation in terms of section 9 of PAJA, in so far as it might be required.

CONCLUSION:

148 The 1st respondent's load reduction policy stands to be reviewed and set aside on the grounds set forth in this affidavit as well as such further grounds which the applicants will make out in its supplementary affidavit in due course.

149 The applicants seek an appropriate cost order against the 1st respondent, and any such parties who oppose the application.

150 The applicants seek a proper, fitting, suitable and effective remedy in this matter.

DEPONENT

I HEREBY CERTIFY THAT THE DEPONENT HAS ACKNOWLEDGED:

a. he knows and understands the contents of this affidavit;

b. he has no objection to taking an oath;

c. he considers the oath to be binding on his conscience.

THUS signed and sworn before me, at Stellenbosch on this 21 **DECEMBER 2022**, the Regulations contained in Government Notice No. R1648 of 19 August 1977 (as amended) having been fully complied with.

COMMISSIONER OF OATHS
FULL NAMES: YOLANDE OVERTON
BUSINESS ADDRESS: c/o R44 & Webers Valley Rd, Stellenbosch
DESIGNATION: Owner 3@1

I certify that the DEPONENT has acknowledged that he/she knows and understands the contents of this affidavit, that he/she does not have any objection to taking the oath, and that he/she considers it to be binding on his/her conscience, and which was sworn to and signed before me and that the administering oath complied with the regulations contained in the Government Gazette No. R 1258 of 21 July 1972, as amended.

SIGNATURE ______
COMMISSIONER OF OATHS - Yolande Overton
Owner of 3@1 Stellenbosch (Ref: 9/1/8/2 - Stellenbosch)

Date: 21/12/22
c/o R44 & Webbers Valley Rd, Stellenbosch

SAKELIGA NPC
REG: 2012/043725/08

DELEGATION OF AUTHORITY

I the undersigned

PIETER JACOBUS LE ROUX

hereby delegate to **TOBIAS VIVIAN ALBERTS**, the following powers and authority:

1) the authority to authorise and/or to institute on behalf of Sakeliga, such further legal proceedings, which may include urgent proceedings, against the **ESKOM HOLDINGS SOC LTD *and such further parties as may be necessary***, which includes but is not limited to appeals and/or reviews of any matter related thereto, and/or the right to have Sakeliga appear, argue, act, support and/or oppose any matter before any state authority or judicial body in furtherance of this delegation.

2) the authority to represent Sakeliga in all matters referred to in paragraph 1) above, and to sign any document on behalf of and in the name of Sakeliga as its lawful representative.

3) the authority to incur costs on behalf of Sakeliga and to appoint, instruct and direct attorneys, experts and/or consultants to assist Sakeliga with any matters relating to paragraph 1) above;

Signed on 19 December 2022

P.J. Le Roux

PIETER JACOBUS LE ROUX – CEO

teenstrydigheid effektiewelik aan te spreek, en

3.3.3. Die aksies neem wat binne hul uitsluitlike diskresie nodig is om die oortreding, botsing en/of teenstrydigheid aan te spreek, wat insluit maar nie beperk is tot die voorstel van wysigings tot die Akte en die belê van 'n spesiale Ledevergadering ten einde daardie wysigings goed te keur.

4. DOELSTELLINGS EN MAGTE VAN DIE MAATSKAPPY

4.1. Ter nakoming van artikel 1 van bylaag 1 tot die Wet, verklaar die Maatskappy hiermee die volgende hoofdoelstellings:

4.1.1. Die bevordering van konstitusionele orde, vryemarkbeginsels en 'n kapitaalkragtige, regverdige, en volhoubare sake-omgewing in die Republiek;

4.1.2. Die skepping van 'n selfstandige sakegemeenskap in die Republiek;

4.1.3. Die behoud van eiendomsreg, holisties gesien, ooreenkomstig die Grondwet van die Republiek;

4.1.4. Om, sonder inperking, bydraes en skenkings te doen tot die Helpende Hand Beursfonds en/of die Solidariteit Helpende Hand NPC;

4.1.5. Om kollektief namens Lede, ondersteuners en die publiek met Owerhede te onderhandel en verhoudinge met Owerhede asook plaaslike, nasionale en internasionale instansies en persone te beding te einde die doelstellings van die Maatskappy te bevorder;

4.2. Die Maatskappy verklaar hiermee die volgende aanvullende doelstellings, maar sonder inperking van die algemene aard van die Maatskappy hoofdoelstellings:

4.2.1. Om as 'n openbare sakewaghond wat fokus op die regte en belange van sy Lede, ondersteuners en lede van die publiek in die algemeen, op te tree;

4.2.2. Om ondersoek in te stel oor gevalle waar die regte van Lede, ondersteuners asook die publiek oor die algemeen, geskend en/of ingeperk word, en om waar nodig ook op te tree ten einde daardie regte te beskerm of te bevorder.

4.3. Die volgende magte word ook, sonder inperking van die algemene magte van die Maatskappy soos uitgeoefen Direksie kragtens die Wet, aan die Maatskappy verleen:

4.3.1. Om deur selfregulering en privaat institusionele infrastruktuur 'n alternatiewe sake-omgewing te skep waarbinne ekonomiese aktiwiteit voortgesit kan word;

4.3.2. Om die Maatskappy se Lede, ondersteuners en lede van die publiek in die uitoefen van hul belange en regte, hetsy op plaaslike, nasionale of internasionale vlak, by te staan, te adviseer, te ondersteun en/of te verteenwoordig.

4.3.3. Om die publiek oor die algemeen by te staan met die bevordering van hul regte op 'n plaaslike, nasionale en internasionale vlak;

4.3.4. Om 'n vrye, onafhanklike en goedgunstige sake-omgewing in die Republiek te beskerm, stimuleer en waar nodig te skep;

4.3.5. Om regsgedinge in te stel, daartoe toe te tree, om sake te opponeer en/of te verdedig, om as *amicus curiae* in sake op te tree, deel te neem aan appèlle, hersienings, en om voor enige Owerheid te verskyn, submissies te maak, te argumenteer, op te tree, teen te staan en/of te ondersteun.

4.3.6. Om met die Owerhede, politieke partye, lede van die sakewêreld, die media asook enige ander lid van die publiek te kommunikeer, te onderhandel, in te debat te tree en om ook waar nodige daardie persone en/of instansies te voorsien met voorstelle, vertoë, submissies, verslae, argument en/of inligting.

4.3.7. Om navorsing ter bevordering van hierdie doelstellings te doen asook om inligting in te samel, statistiek op te bou, te verwerk en te publiseer;

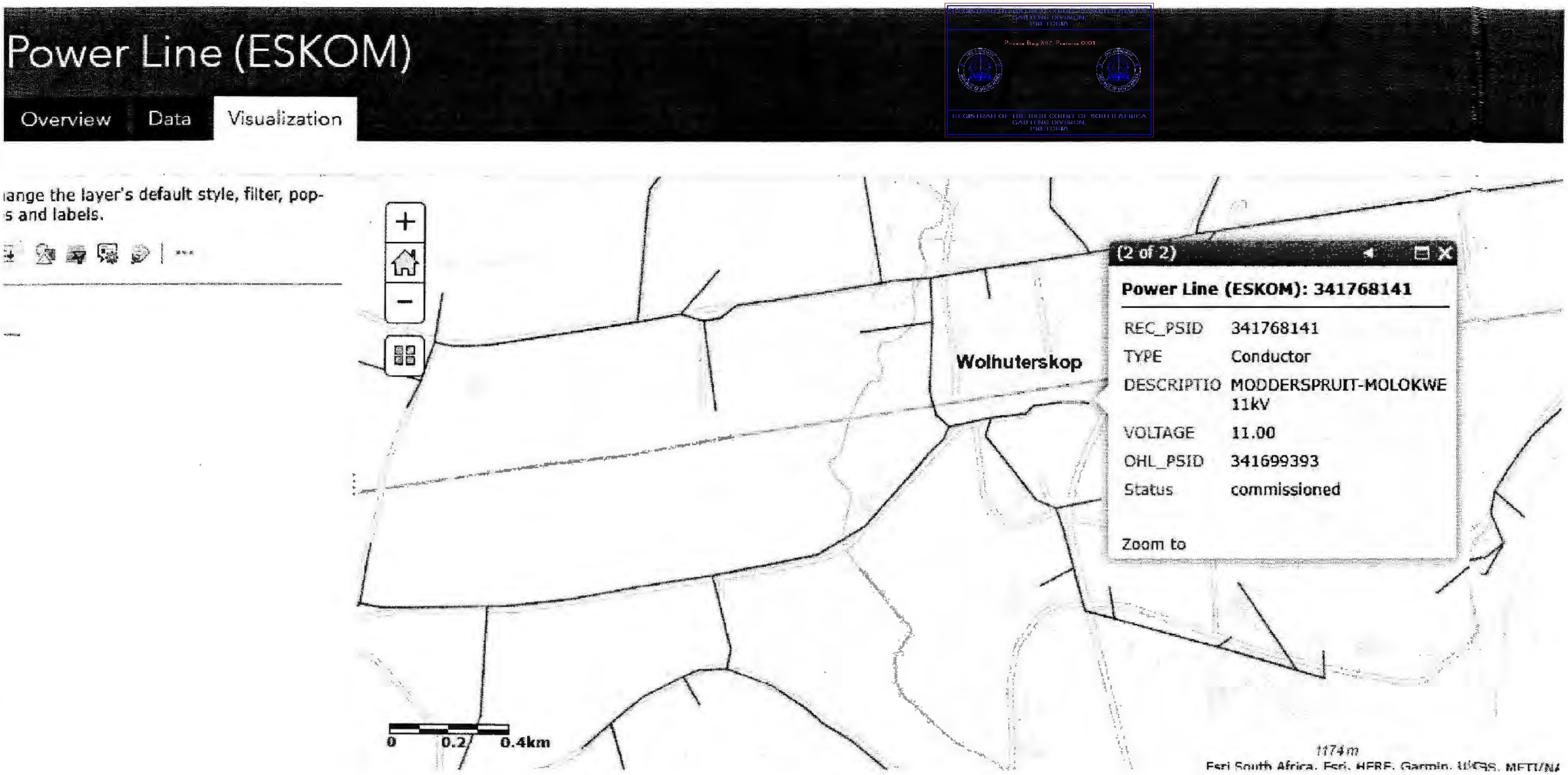
4.3.8. Om onafhanklike regsadvies oor enige saak wat enige doelstelling van hierdie Akte raak, te bekom en waar nodig om ook regsverteenwoordiging aan te stel om die Maatskappy te verteenwoordig in die bevordering van hierdie doelstellings.

4.3.9. Om met ander organisasies of persone met soortgelyke doelstellings te onderhandel, ooreenkomste te sluit, projekte te hardloop, sake te bevorder, befondsing te voorsien, befondsing te ontvang, ondersteuning te bied en/of te affilieer.

4.3.10. Om deel te neem in die bestuur, beheer of aktiwiteite van enige ander organisasie wat soortgelyke doelstellings as die van die Maatskappy het en om in hulle te belê, belange te bekom en/of om vennootskappe of samewerkingsooreenkomste met hulle aan te gaan.

4.3.11. Om enige persoon of organisasie te vergoed vir hul dienste gelewer aan of

22/12/2022-11:31:00 AM

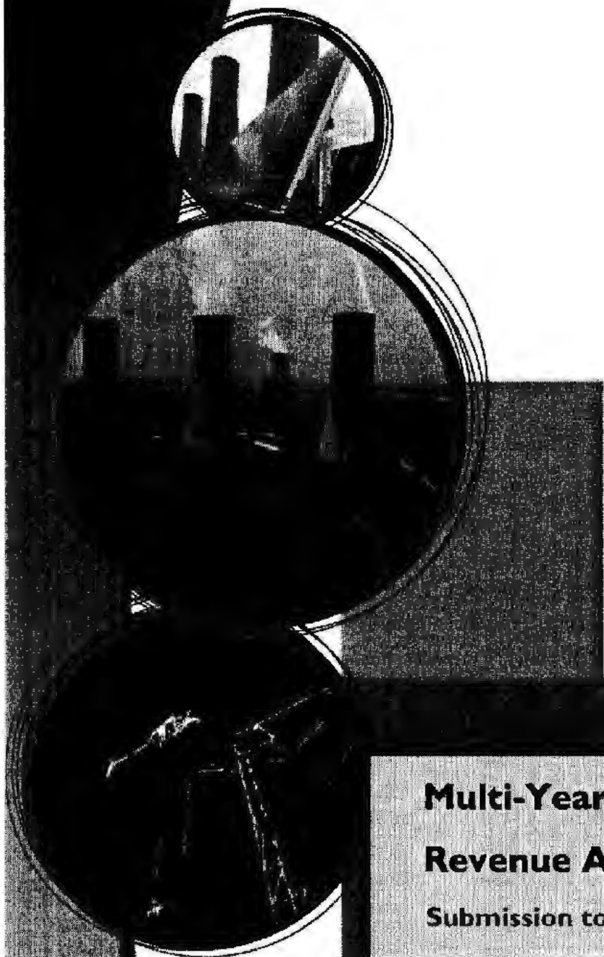


X3 0059

22/12/2022-11:31:00 AM

X4 0060

Eskom



REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA
Private Bag X67, Pretoria 0001
REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA

Distribution Licensee (Dx)

Multi-Year Price Determination (MYPD) 5
Revenue Application for FY2023 – FY2025

Submission to NERSA

June 2021

Contents

LIST OF TABLES

LIST OF FIGURES

1 Executive Summary

1.1 Introduction

This document details the Distribution Licensee revenue application for the FY2023 to FY2025 setting out key challenges and revenue requirements. This application for the Distribution License of Eskom Holdings Ltd (herein after referred to as the Licensee) is to be read in conjunction with the submissions of the other Eskom licensees.

The Licensee application supports the Eskom mission to provide sustainable electricity solutions to promote economic growth and social prosperity for South Africans. This is achieved through operating the distribution network to supply electricity to customers in its area of supply as specified within the Distribution licence. This supports the right of entry to third parties such as Independent Power Producers (IPPs) to the Distribution network for the distribution of power.

The Licensee application for the MYPD5 control period is prepared as per the prescribed MYPD methodology. The table below summarises the efficient revenue being applied for in the MYPD5 period. NERSA has already determined that in addition to the MYPD5 revenue determination, previous RCA determinations of R2 955m will be recovered in FY2023.

TABLE 1: DISTRIBUTION FY2023 – FY2025 REVENUE REQUIREMENT (R'M)

Allowable Revenue (R'm)	AR	Formula	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Regulated Asset Base (RAB)	RAB		134 849	139 596	142 534	145 107	146 059
WACC %	ROA	x	-1.99%	0.69%	0.87%	1.65%	3.04%
Returns			(2 685)	966	1 244	2 387	4 433
Primary energy	PE	+	13	13	14	15	15
International purchases	PE	+	-	-	-	-	-
IPPs	PE	+	-	-	-	-	-
Environmental levy	L&T	+	-	-	-	-	-
Carbon tax	L&T	+	-	-	-	-	-
Arrear debt	E	+	5 666	6 511	7 110	7 802	8 541
Operating costs	E	+	23 966	25 090	26 044	27 256	28 844
Research and Development	R&D	+	-	-	-	-	-
Depreciation	D	+	7 397	7 539	7 426	7 548	7 735
MYPD5 Allowable revenue			**34 357**	**40 119**	**41 839**	**45 007**	**49 568**
Approved RCA's for liquidation	RCA		2 955	-	-	-	-
MYPD5 Allowable revenue including RCAs	R'm		**37 312**	**40 119**	**41 839**	**45 007**	**49 568**

Note: Research and Development revenue requirement is included in operating costs

The Licensee will respond to a changing market conditions by:

- Stimulating local demand by engaging customers to maintain and grow existing sales.
- Grow the market by attracting new customers and incentivise large customers to invest in the country.

The Licensee intends to optimally manage all costs. This is planned to be achieved through:

- Prioritising capital investments to build assets that support network performance in order to deliver reliable network performance.
- Ensuring adequate maintenance spend in support of regulatory compliance.
- Ensuring accurate and timeous billing of customers for sustainable revenue streams.
- Optimising manpower cost while maintaining the critical and scare skills required for operations.

The salient factors that underpin the requested Distribution licensee revenue requirement are sales volumes, return on assets, maintenance, employment benefit cost, impairment and other cost.

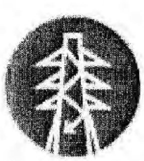
1.2 Sales volumes

Eskom's sales have declined over the past years, with the outlook remaining relatively depressed in the years ahead. Since 2006, sales have declined by an estimated average of 0.5% per year. A significant decline is attributed to large power users as a result of high ore extraction costs and volatile commodity markets, particularly in the ferrochrome, steel, gold and platinum industries. During the MYPD5 period the decrease in sales is anticipated primarily from exports and standard tariffs. Eskom's projected compounded average growth rate (CAGR) is -0.5% for the MYPD5 period while the average annual growth rate (AAGR) of 0.043%. The forecast sales volumes are detailed in the table below.

TABLE 2: SALES FORECAST VOLUMES (GWH)

Sales Volume (GWh)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Standard customers	180 868	168 529	172 656	171 549	171 440	170 370	170 141	169 476
NPA	10 118	9 755	9 722	10 282	10 311	10 282	10 282	10 282
Total LOCAL sales	**190 986**	**178 284**	**182 379**	**181 831**	**181 751**	**180 652**	**180 424**	**179 758**
International (SAE)	15 095	12 890	12 054	11 748	10 876	10 815	10 815	10 815
Total Eskom sales	**206 081**	**191 174**	**194 433**	**193 579**	**192 627**	**191 467**	**191 238**	**190 573**

1.3 Return on Assets



The Electricity Regulation Act (ERA) and the Electricity Pricing Policy allows for the recovery of efficient costs and a fair return on revalued asset valuations. In accordance with the MYPD methodology, the Distribution Licensee is allowed to earn a return on the installed Regulatory Asset Base (RAB) as well as on relevant capital works that are under construction.

The MYPD5 RAB values as are based on an independent asset valuation study as well as the planned capital expenditure. These capital investments are required to strengthen and expand the grid to connect new loads, generation sources and to replace assets which have reached the end of their technical life.

The RAB value increases over the MYPD5 period as new assets are brought into commercial operation and planned projects investments are incurred. Distribution capital investment requirements for FY2023 – FY2025 are included in the table below.

TABLE 3: ACTUAL AND PLANNED CAPITAL INVESTMENTS (R'M)

Capital expenditure (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Direct Customers	1 003	931	1 099	1 282	1 235	1 384	1 539	1 601
Strengthening	962	947	1 667	1 857	2 236	2 193	2 569	2 747
Refurbishment	457	451	990	1 424	1 208	1 868	1 311	1 400
Land & Rights	9	15	53	39	41	59	124	134
IPP Connections	55	61	71	430	730	1 030	1 215	1 015
Asset Purchases	157	230	298	564	678	492	126	128
BESS project	-	-	4 281	3 247	4 524	2 074	1 139	-
Eskom funded	**2 643**	**2 635**	**8 459**	**8 843**	**10 652**	**9 100**	**8 023**	**7 025**
DMRE Funded	2 432	2 691	2 339	3 013	3 165	3 323	3 489	3 663
Total capex	**5 075**	**5 326**	**10 798**	**11 856**	**13 817**	**12 423**	**11 512**	**10 688**

1.4 Operating Expenditure

Operating expenditure includes all costs involved with the day-to-day running of the business. Distribution's operating expenditure includes employee costs, maintenance and other expenses. The compound average growth rate (CAGR) for the period FY2023 – FY2025 for operating costs is 3.8%, which is below expected inflation.

The CAGR for the period FY2023 – FY2025 for employee expenses is 3.5%, which is below projected inflation. In alignment with cost reduction objectives, the Distribution headcount will be contained over the planning period as outlined in the table below.

TABLE 4: DISTRIBUTION EMPLOYEE EXPENSES (R'M) AND HEADCOUNT

Employees expenses	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Employee expenses (R'm)	11 414	11 560	11 862	12 032	12 545	13 158	13 827	14 699
Head count	17 453	17 594	17 604	17 520	17 422	17 314	17 714	17 714

The CAGR for the period FY2022 to FY2025 for maintenance and other operating costs, is 5.1% and 5.6% respectively.

1.5 Depreciation

Depreciation allows the Licensee to incrementally recover the principal of the capital invested in its assets over their lifetime. The asset valuation is aligned with the MYPD Methodology, which requires the use of an asset valuation methodology that accurately reflects replacement value using the MEAV technique. The depreciation reflected in the table below was calculated based on the asset valuation study conclusions as well as considering new asset investments planned for transfer to commercial operation.

TABLE 5: REGULATORY ASSET BASE AND DEPRECIATION (R'M)

Regulatory Asset Base and depreciation (R'm)	Decision FY2021	Decision FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Regulatory Asset Base	90 853	89 917	134 849	139 596	142 534	145 107	146 059
Depreciation	7 617	8 335	7 397	7 539	7 426	7 548	7 735

1.6 Arrear debt - Impairment costs

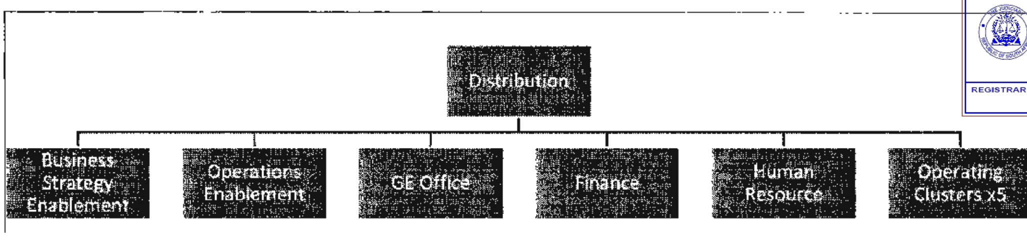
While the licensee records good payment from large industrial, commercial and major metropolitan customers, however there are areas of major concern regarding residential and municipal debt. Municipal overdue debt has increased significantly in the past few years and remains a concern.

In this application Eskom has limited the impairment to 2% of revenue despite the fact that our current actuals are closer to 4%. The 2% impairment implies a payment level of 98% of all billed revenue including interest. The 2% impairment will cater for credit losses incurred as a result of liquidated business; as well as non-payment by certain customer groups.

2 Distribution Licensee context

This section describes the role and responsibilities of the Distribution Licensee. The Licensee, distributes and supply electricity to customers in its supply areas by operating the network, as specified in the Distribution License granted by the National Energy Regulator of South Africa (NERSA). Distribution Licensee operating structure is reflected on the Figure below.

FIGURE 1: REPRESENTATION OF THE DISTRIBUTION LICNSEE ORGANISATION



The Licensee's mandate is to enable economic growth by harnessing employee expertise to provide reliable energy and related services to our customers by building, operating, and maintaining assets in a financially sustainable manner. The operating clusters are a result of an amalgamation of certain provincial operating units. Key to a sustainable Distribution business will be to focus on the following strategies:

- Sustain sales
- Intensify revenue collection efforts
- Reduce energy losses
- Improve network performance
- Enhance customer experience

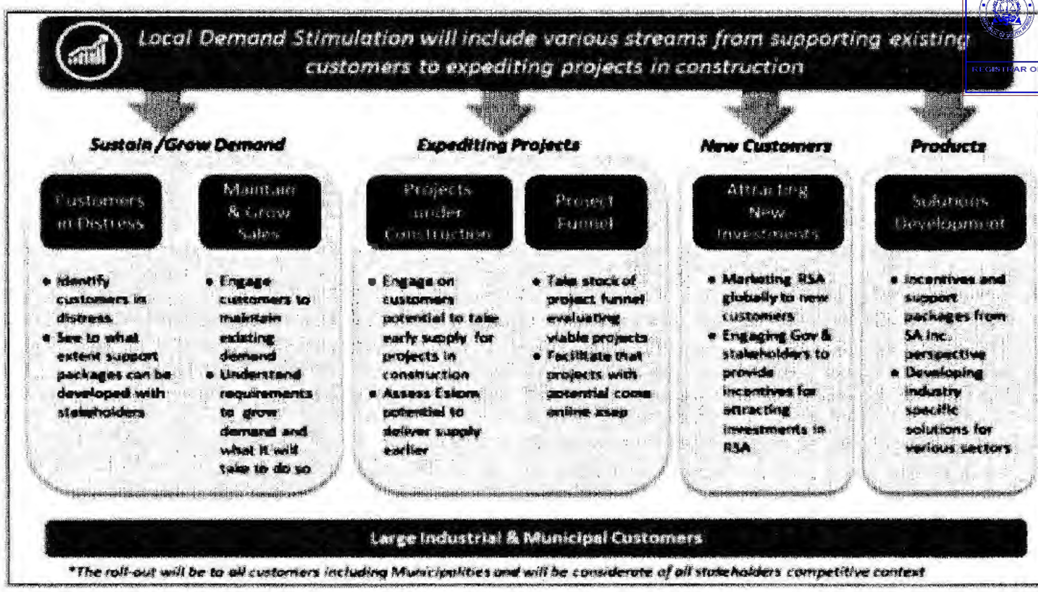
2.1 Sales growth initiatives

Eskom sales volumes have been on the decline due to constrained economic conditions, systems constraints, perceived high prices and customer energy usage optimization and migration. The global economic impact from the Pandemic has exacerbated the downward trend and recovery is expected over many years to come, albeit it being slow. Internal IDM initiatives has also accelerated energy efficiency among customers. Municipal and other sectors anticipated to take slightly longer to recover on account that SA economy was already in a recession prior to the onset of the COVID pandemic.

Eskom will continue to grow sales by stimulating demand for local and export sales. The growth strategy will be achieved by, *"Retaining sales, growing sales and revenues by responding to customer needs, speeding up connections and collections, whilst consistently delighting customers."*

Eskom has developed a demand stimulation framework with four key elements that are sustaining and growing demand, expediting projects, attracting new customers and implementing innovative products.

FIGURE 2: DEMAND STIMULATION FRAMEWORK



Research and information from individual customer engagements highlighted the need for more flexible and incentivized electricity pricing and product offerings. Product development has consequently anchored itself along four areas that are incentivizing incremental sales, unlocking new connections, expert advice to facilitate additional use of electricity and solutions development for new markets and technologies to sustain and increase future sales.

To unlock barriers to grid connection, Eskom successfully piloted the funding of upfront connection charges to large power users with flexible repayment periods available to the customers. This option is now available to customers that declined quotations due to affordability.

To fully benefit from the demand stimulation framework, establishing a country platform with the involvement of all key role players to sustain local industrial and mining operations and all sectors of the economy is required. With an integrated and focused country approach

uA-there is the opportunity to encourage local investment from new and existing customers making the most of the South African growth potential in the medium to longer term.

2.2 Customers served

The Licensee in the fulfilment of its mandate provides energy to 6.7m customers and focuses is on sales growth (sell), revenue collection (collect) and customer satisfaction (experience).

In the past seven years, an additional 1.6m new customers were added to the network. The key driver for growth in customer numbers was is in the prepaid segment from the electrification program in support of the universal access. Once these customers are connected they form a part of the Eskom customer base to be serviced. The number of Eskom customers is shown in the table below.

TABLE 6: NUMBER OF ESKOM CUSTOMERS

Customer Category	Actual FY2017	Actual FY2018	Actual FY2019	Actual FY2020	Projection FY2021	Growth to date
Redistributors	802	800	800	805	804	-1
Residential	5 838 754	6 120 122	6 358 523	6 577 905	6 720 150	142 245
Commercial	50 956	51 848	52 556	52 909	52 880	-29
Industrial	2 706	2 703	2 705	2 684	2 649	-35
Mining	1 012	993	981	961	945	-16
Agriculture	81 806	81 638	81 303	80 451	79 115	-1 336
Rail	510	501	493	475	475	0
Local Customers	**5 976 546**	**6 258 605**	**6 497 361**	**6 716 190**	**6 857 018**	**140 828**

At the end of the FY2021, municipalities, industrial and mining customers accounted for 84% of the total sales volumes. Residential customers supplied by Eskom make up 98% of the number of Eskom customers but only consumes 6% of the local sales volumes.

2.3 Tariffs

Eskom sales revenues are recovered through the Distribution Licensee.

Customers purchase electricity sales through standard tariffs, local and international negotiated pricing agreements (NPAs) and international utility tariffs. Standard tariffs provide pricing options to meet different customers' electricity consumption patterns and service needs.

There are different standard tariffs based on supply size, complexity, geographic location, municipal and non-municipal supplies as well as generator tariffs. There are three main standard tariff categories that are the same for municipal and non-municipal customers, that is, urban large, rural and residential. Standard tariffs include inter-tariff subsidies to rural and residential tariffs to support customer affordability.

The objectives for the tariffs per the Eskom's "Strategic direction and tariff design principles for Eskom's tariffs" are as follows:

- Improved cost-reflective tariff structures (within the allowed revenue) i.e. fixed versus variable charges are representative of the cost structure.
- Partner for mutual benefit with our customers for sharing of volume risk.
- Ensure reasonable compensation for the use of networks by generators and loads.
- Incentivize customers to stay connected to the grid.
- Increase sales and ensure adequate recovery of costs
- Enable better management of demand and supply.

In pursuit of the tariff objectives, Eskom submitted the Retail Tariff plan (RTP) to NERSA in 2020 for approval. Upon NERSA approval, the standard tariffs will be adjusted in the year of implementation to reflect the allowable price level through the annual increase adjustment as required by the NERSA ERTSA process.

2.4 Energy losses management

Eskom Distribution monitors energy losses continuously and has embedded within its operations various interventions aimed at addressing the energy losses. These interventions are from a technical, commercial, and social perspective. Some of these interventions are:

- Reconciliation of the energy delivered and energy sold (i.e. energy balancing) at the reticulation feeder level in order to prioritize high loss feeders for normalization
- Disconnection of illegal connections, meter tampers and imposition of penalties (tamper substantiate with fines)
- Estimation and recovery of revenue for historic unaccounted energy where tampered, faulty or missing metering installations are encountered
- Revision of Supply Group Codes on prepaid meters to prevent the use of illegal prepaid vouchers
- Implementation of technologies in the form of smart/split meters with steel enclosures to prevent access to the meter
- Customer education, social mobilization and partnership campaigns to drive behavior change
- Investigations and subsequent prosecution of criminals/syndicates perpetrating electricity theft through the sale of illegal prepaid vouchers and providing illegal electrification and meter tampering services

2.5 Electrical supply networks

To meet customer needs the Licensee builds, operates and maintains the Eskom medium and low-voltage electricity supply networks (distribution and reticulation networks). This is to ensure reliable, secure and environmentally sustainable supply of electricity which meets customer expectations, supports government's universal access agenda and the Eskom growth strategy.

Geographically, the distribution network spans a landscape of approximately 49 107 km of distribution lines, 301 916 km of reticulation lines, and more than 7 734 km of underground cables in South Africa, this represents the largest power-line system in Africa. Distribution operating structure is represented in cluster of 5 operating units that are divided into 27 operating zones with execution of work through 306 Customer Network Centres (CNCs).

The Licensee aspirations for the immediate and near future are:

- **Operate a sustainable Distribution network that delivers on customer expectations**
  Distribution will aim to build and maintain its ageing network by maintaining the current network performance levels and limiting energy losses. This is sustained through disciplined execution.
- **Migrate towards compliance with the regulatory framework governing network performance**
  The business continues to manage its regulatory obligations whilst balancing investment choices with customer's needs.
- **Zero Harm to employees, Contractors and Environment**
  The Distribution Group aims to make significant step changes through Zero Harm initiatives coupled with supplier and public education programs, to improve safety performance.
- **Create an agile and innovative workforce**
  Further improve employee productivity by reviewing the efficiency and effectiveness of Eskom's business model, and ensuring a motivated workforce. Emphasis will be placed on retaining core skills together with the management of skills and talent.
- **Proactively partner towards a sustainable distribution industry**
  Actively partner with stakeholders to evolve the wider Electricity Distribution Industry in South Africa. This is to ensure provision of accessible and sustainable electricity.
- **Electrification**
  Electrification remains a priority with thousands of households to be connected during the next three years and plans to expedite government's Universal Access Program

(UAP). Eskom acts on behalf of the government in executing the electrification program that is fully funded from the DMRE.

Distribution's current network performance in the past few years has improved and stabilised in terms of the duration and frequency of customer interruptions. In order to sustain the current network performance, Distribution Group aims to prudently invest capital and maintain the plant maintenance regime.

2.6 Integrated demand management (IDM)

In terms of Section 14 of the MYPD methodology, Eskom is required to implement integrated demand management (IDM). The IDM role in Eskom is a vital mechanism to manage the electricity supply and demand balance using a multi-pronged energy management approach. In this MYPD5 application, the IDM allowable costs are included in the Distribution Licensee.

3 Sales volumes

For the MYPD5 revenue application, one of the key assumptions is the latest available forecasted sales volumes. In accordance with the NERSA MYPD methodology, a revision of the forecasted sales volume to reflect the prevailing situation must be presented for consideration to NERSA. This is especially pertinent to take into account the impact of the pandemic and the recovery of the South African economy.

Eskom makes every effort to at least maintain its levels of sales and to increase sales, if possible. However, as is demonstrated below, the sales volume is very much an outcome of the economy of the country. However much Eskom may have wished the level of sales to improve, or at least remain at the same level during the pandemic, it was not possible. Eskom is making every effort to address its operational environment to improve its availability within the constraints that Eskom has to operate within. Thus, it is submitted that an improvement in the economic conditions in the country is a requirement for a likely improvement in the level of Eskom sales. Sales volumes cannot be improved in isolation.

Eskom is presently in the process of undertaking a review of the sales forecast. The outcome will be shared with NERSA before it makes the MYPD5 decision thereby incorporating the latest updates. Eskom has experienced the forecasting of its sales to be very dynamic and every effort will be made to provide the latest sales projections.

The forecasted sales volumes as provided below, refer to the FY2023 through to FY2025 for all customer categories that are on standard tariffs, local negotiated pricing agreements (NPA) and international sales (exports). During the MYPD5 period, the forecasted sales volume decline will be 0.5% including the leap year and 0.3% excluding the leap year. In this sales volume forecast, the decrease in sales is anticipated primarily from exports and standard tariffs. Eskom's projected compounded average growth rate (CAGR) is -0.3% for the MYPD5 period while the average annual growth rate (AAGR) over the MYPD5 period is -0.5%.

The table below shows the Eskom Sales projected and forecasted sales from FY2021 to FY2027 split between Standard customers, the NPA and International sales.

TABLE 7: TOTAL ESKOM SALES FROM FY2021 TO FY2027

Sales Volume (GWh)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Standard customers	180 868	168 529	172 656	171 549	171 440	170 370	170 141	169 476
		-6.8%	2.4%	-0.6%	-0.1%	-0.6%	-0.1%	-0.4%
NPA	10 118	9 755	9 722	10 282	10 311	10 282	10 282	10 282
		-3.6%	-0.3%	5.8%	0.3%	-0.3%	0.0%	0.0%
Total LOCAL sales	**190 986**	**178 284**	**182 379**	**181 831**	**181 751**	**180 652**	**180 424**	**179 758**
		-6.7%	2.3%	-0.3%	0.0%	-0.6%	-0.1%	-0.4%
International (SAE)	15 095	12 890	12 054	11 748	10 876	10 815	10 815	10 815
		-14.6%	-6.5%	-2.5%	-7.4%	-0.6%	0.0%	0.0%
Total Eskom sales (Including internal)	**206 081**	**191 174**	**194 433**	**193 579**	**192 627**	**191 467**	**191 238**	**190 573**
		-7.2%	1.7%	-0.4%	-0.5%	-0.6%	-0.1%	-0.3%

Eskom's sales growth has trended downwards over the past three years, with the outlook remaining relatively depressed in the years ahead. Since 2006, sales have declined by an estimated average of 0.5% per year. The decline can be generally attributed to large power users as a result of low competitiveness, high ore extraction costs and volatile commodity markets – particularly in the ferrochrome, steel, gold and platinum industries.

It is important to emphasise that the SA economy had shown signs of significant distress prior to the onset of the pandemic and its associated lockdowns at the end of March 2020. Although South Africa is still viewed as an emerging market, several factors have contributed to the decline in underlying economic growth of the country. These include, but are not limited to, finite natural resources, low investor confidence, infrastructure bottlenecks, labour unrest, load shedding, rising local debt and unemployment.

According to Econometrix year-end Outlook for 2020, the impact of lockdown resulted in the steepest downturn in global economic activity since the Great Depression of the early 1930s. In South Africa, lockdown restrictions have had far reaching consequences and contributed to the substantial downward momentum of an already compromised economy. According to a recent Quarterly Labour Force Survey Quarter 2: 2020 results, released by Statistics South Africa on 29 September 2020, the South African economy shed 2,2m jobs in the second quarter of 2020. In a further report by StatsSA's titled: "Steep slump in GDP as COVID-19 takes its toll on the economy" it is stated that: "Manufacturing output shrank by 74.9%.

Furthermore, plagued by work stoppages and lower demand for steel, factories specialising in metals and machinery were severely affected. As can be expected the ban on alcohol sales had a significant impact on the food and beverage division of manufacturing". This has a downstream effect on the various associated packaging industries.

During lockdown, air travel came to an almost complete halt, contributing to the fall in economic activity in the transport and communication industries. There was also less activity by rail and road freight operators due to restrictions on the production, the movement of various goods locally and port closures.

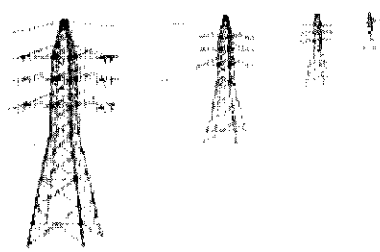
The closure of tourist accommodation, hospitality and leisure complexes were further notable drags on economic activity. Reduced activity in these sectors has a direct impact on the Commercial and Municipal categories in which the associated customers are embedded. This is echoed by a report from the Department of Tourism revealing the extent of tourist decline.

Wholesalers and motor vehicle traders also reported significant declines, as car rental agencies consumers delayed purchases. This has negatively affected the smelting and fuel industries, due to a rapid decline in demand.

Finance and personal services, these two industries that have shown a great deal of resilience over the last decade, did not escape the maelstrom. The finance industry, which includes banking, insurance services, real estate and business services, fell by 28.9%. Personal services recorded its first quarter of negative growth since 2009. Businesses, such as gyms and hairdressers, closed their doors and hospitals halted elective operations. The cancelation of sporting and recreation events also dragged the industry lower."

The above impact of the Covid-19 pandemic on Eskom's electricity sales was immediate, with the largest impact materialising during April and May 2020. As at 30 September 2020, the sales impact has been estimated at approximately 8.24 TWh. A recent United Nations Development Programme (UNDP) study has revealed that the local economy will take up to five years to recover.

Given the numerous factors above, electricity sales growth is expected to be declining over the next few years. However, Eskom's aims to grow sales over the medium term supported by innovative products, solutions and tariffs in collaboration with customers to address their needs and aspirations.



3.1 Sales volume forecasting assumptions

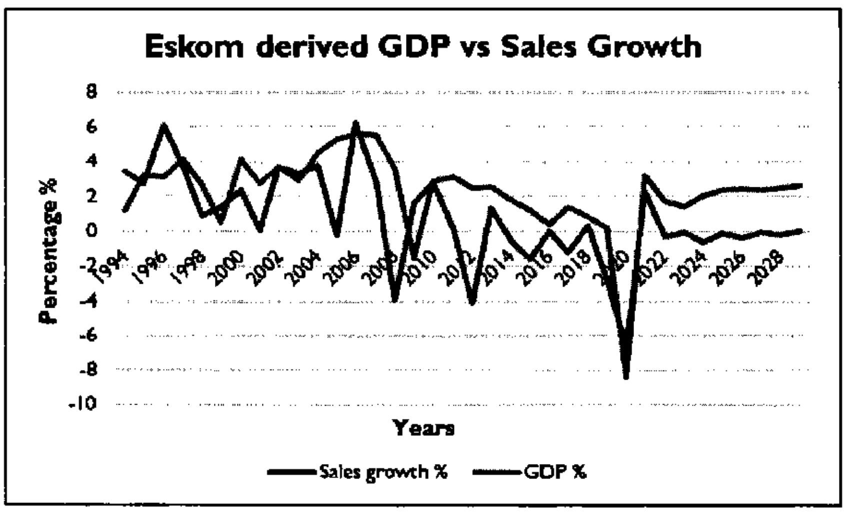
The sales volume forecast is based on various assumptions reflecting the different types of customers' electricity needs and influences on diverse customer consumption profiles. There are some similar assumptions used for all customers but with varying impacts.

Key assumptions include the gross domestic product (GDP) growth, commodity market performance and prices, demand response savings, weather conditions, customer projects, industrial action and impact of the leap year.

3.1.1 Gross Domestic Product (GDP)

Historical trends indicate that electricity consumption grows at a slower rate than the economy. In the sales volume forecast, the gap between sales growth and GDP is widening due to less energy intensive sales during the forecast years and the economy migrating towards a greater service oriented economy. In addition, several mines and large industrial customers are down scaling or closing down completely, in line with the factors mentioned above. It is therefore assumed, that the margin between GDP growth and electricity growth will continue to widen into the future. The figure below illustrates the anticipated gap between GDP and sales growth as explained above.

FIGURE 3: ACTUAL AND PROJECTED GDP VS SALES GROWTH RATES



3.1.2 Commodity prices

A recent slump in commodity prices had led to subdued electricity consumption among energy intensive industries.

Ferrous metal commodity prices were further compromised as a result of the pandemic. It is anticipated that the recovery of commodity prices will be slow and steady during the MYPD5 period. As customers with smelting capacity become more pressurised, these customers will migrate towards more efficient furnace utilization, which does not bode well for electricity sales. This trend has been assumed in the sales forecast for the entire MYPD5 period.

Platinum mines have been hit by static low commodity prices, labour action, as well as the Pandemic inspired global recession. However, growth in the sector is driven by new projects and expansions at existing mines. Despite some projects having been delayed due to the Pandemic, moderate growth is still expected in the Platinum sector over the MYPD5 period.

Gold prices reached record highs in 2020 as the metal remains a safe haven for investors. The price is expected to remain in favourable territory at least until a proven vaccine for COVID 19 becomes widely available. Gold mines remain under pressure to curb rising labour and extraction cost, with some mines reaching their end of life.

TABLE 8: COMMODITY PRICES (SOURCE: WORLD BANK COMMODITY OUTLOOK)

World Bank Commodities Price Forecast (nominal US dollars) — Released: October 22, 2020

Commodity	Unit	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030
								Forecasts						
Metals and Minerals														
Aluminum	$/mt	1 867	1 665	1 604	1 968	2 108	1 794	1 660	1 680	1 731	1 784	1 838	1 894	2 200
Copper	$/mt	6 863	5 510	4 868	6 170	6 530	6 010	6 050	6 300	6 374	6 449	6 525	6 602	7 000
Iron ore	$/dmt	97.0	55.9	58.4	71.8	69.8	93.8	107.0	105.0	103.2	101.5	99.7	98.0	90.0
Lead	$/mt	2 095	1 788	1 867	2 315	2 240	1 997	1 820	1 850	1 885	1 911	1 937	1 963	2 100
Nickel	$/mt	16 893	11 863	9 595	10 410	13 114	13 914	13 500	13 800	14 213	14 638	15 076	15 530	18 000
Tin	$/mt	21 899	16 067	17 934	20 061	20 145	18 661	16 900	17 100	17 673	18 264	18 876	19 508	23 000
Zinc	$/mt	2 161	1 932	2 090	2 891	2 922	2 550	2 200	2 300	2 321	2 343	2 365	2 387	2 500
Precious Metals														
Gold	$/toz	1 266	1 161	1 249	1 258	1 269	1 392	1 775	1 740	1 696	1 650	1 618	1 580	1 400
Silver	$/toz	19.1	15.7	17.1	17.1	15.7	16.2	21.0	18.1	18.1	18.1	18.1	18.1	18.0
Platinum	$/toz	1 384	1 053	987	948	880	864	875	870	900	943	982	1 022	1 250

3.1.3 Furnace load reduction in winter

It is assumed that a substantial amount of furnace load will not be utilised during winter due to the high winter energy prices. As a result of the seasonal tariff the majority of smelters usually perform maintenance on their furnaces during the winter months. Depending on trading conditions, furnace utilisation is assumed at around 90% in the summer months.

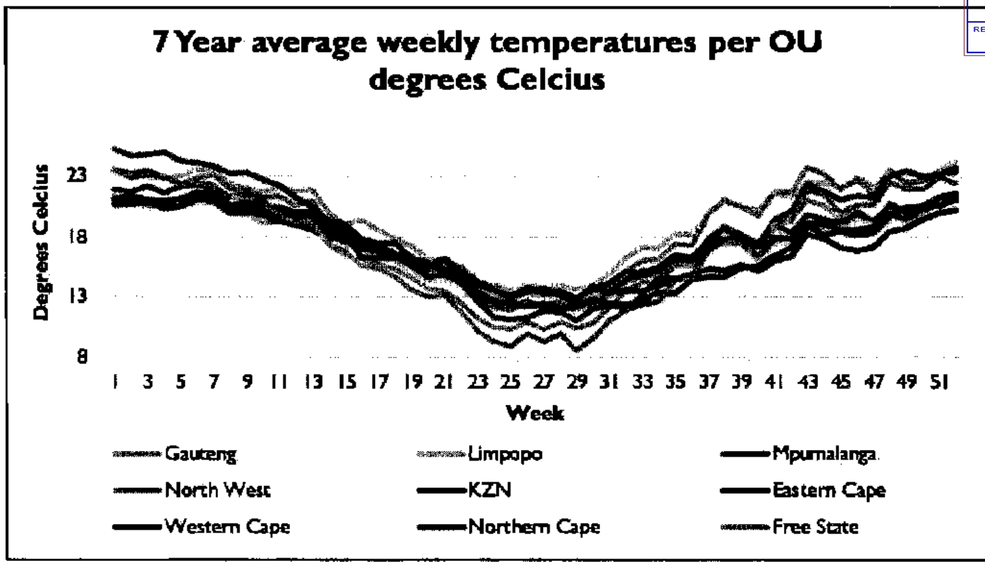
3.1.4 Energy efficiency demand side management (EEDSM)

The impact of EEDSM initiatives is embedded in the forecasted sales volumes and it is therefore captured in the underlying historic sales volume base used in the trend analysis. The sales volume forecast assumption for EEDSM is that the historic EEDSM savings will continue during the application period. No new EEDSM initiatives has been taken into consideration for future years.

3.1.5 Weather conditions

Residential and Agricultural sales are weather sensitive by nature. As customary, average weather conditions have been applied as a key input parameter to predict the sales of all the weather sensitive customers. These average weather profiles per region is shown in the figure below.

FIGURE 4: 2014-2020 YEARLY AVERAGE TEMPERATURES



(SOURCE: VITAL WEATHER)

3.1.6 Leap year impact

Every fourth year, February month has 29 days and this is recognised as a leap year. Consequently, there are additional sales in February 2020, due to the extra day. The leap year impact has also been taken into account for 2024.

3.1.7 New customer projects (loads)

Only projects that have a high probability of start-up and have budget quotations accepted by customers are included in the sales forecast.

3.1.8 Co-generation (Co-gen)

The sales forecast also incorporates the co-generation capacity of large customers, which have the capability to generate and wheel energy between each their respective sister plants.

It should be noted that their respective co-generation usage is dependent on plant availability and performance.

On the contrary, there are also co-generation customers that are envisaged to sell electricity to the Eskom system operator. These have been excluded from the sales volume forecast, as they are regarded as independent power producers (IPPs).

3.2 Forecasted sales volumes by customer category

The figure below shows the percentage split per forecasted sales category. The Distributors' (Municipal) sales volume of 46% reflects Eskom's sales to all municipalities and Metro's. In many municipal areas, the majority of sales are consumed by residential and commercial consumers. The Industrial sector contributes 23% of Eskom Sales, while Mining constitutes a further 15%. The remaining sectors contribute to the residual 16% of Eskom sales. The customer categories used to derive the forecasted sales volumes are based on sectors as shown in the table below.

FIGURE 5: SALES PER CATEGORY AS AT Q3 FY2021

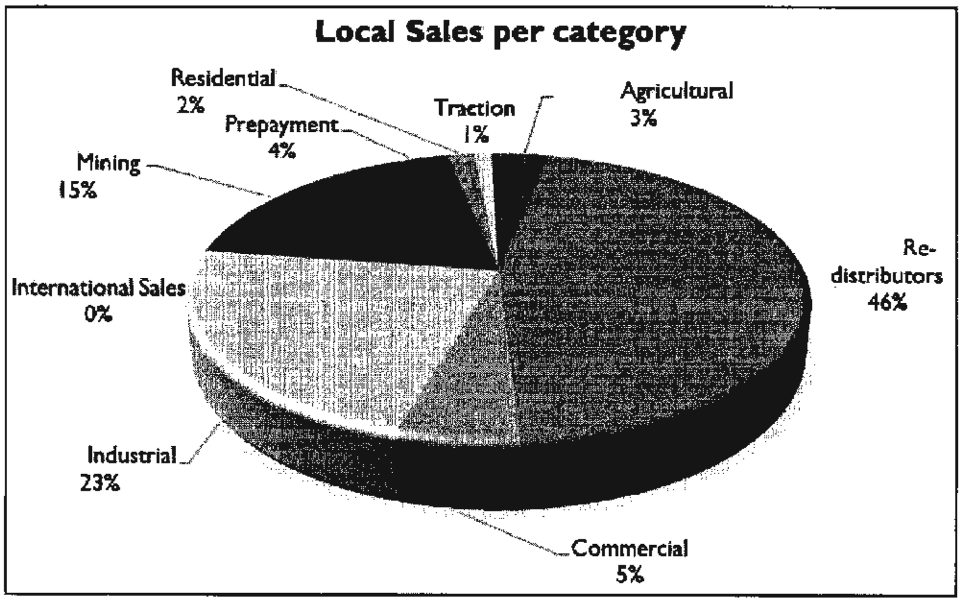


TABLE 9: MYPD5 FORECASTED SALES PER SECTOR

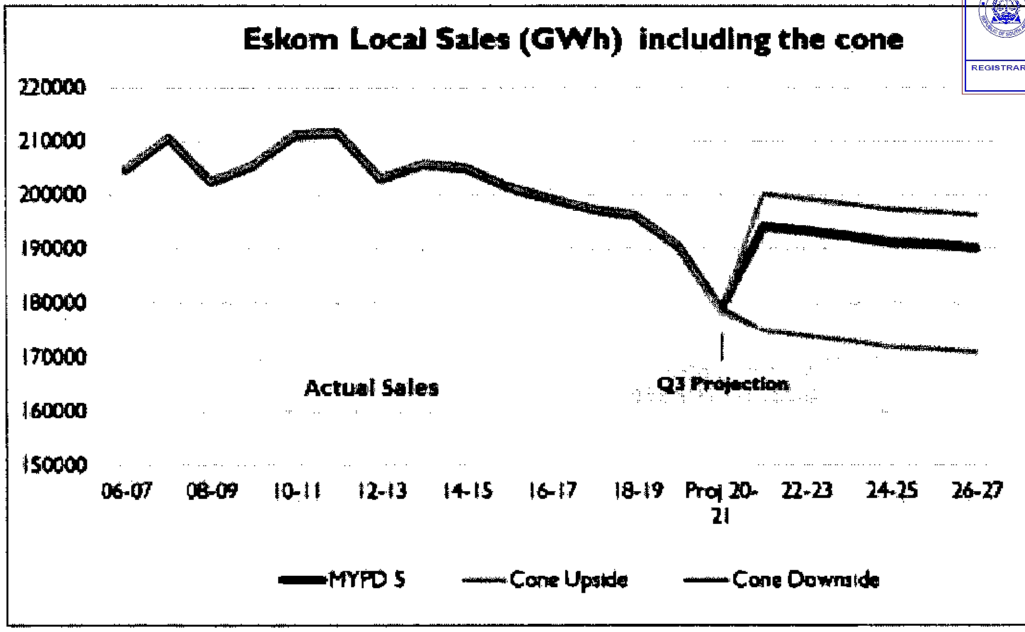
Sales Volume (GWh)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Distributors	85 898	82 231	83 455	82 875	82 463	81 750	81 364	80 962
Industrial	45 610	40 351	42 067	42 047	42 341	42 154	42 272	42 129
Mining	28 703	26 689	27 502	27 593	27 557	27 407	27 307	27 120
Gold Mining	9 708	8 836	8 696	8 631	8 436	8 250	8 081	7 852
Platinum Mining	11 537	10 513	11 038	11 175	11 276	11 293	11 339	11 377
Other Mining	7 458	7 339	7 768	7 787	7 845	7 863	7 886	7 891
Traction	2 600	1 963	2 158	2 162	2 178	2 184	2 280	2 292
Residential incl Public light	3 418	3 379	3 360	3 340	3 329	3 303	3 285	3 269
Commercial	10 486	9 707	9 959	9 965	10 005	9 988	10 006	10 029
Agricultural	5 770	5 617	5 646	5 647	5 668	5 654	5 659	5 665
Prepayment	7 875	7 584	7 555	7 526	7 535	7 539	7 578	7 620
International A	94	87	94	94	94	94	95	95
Internal Sales	447	592	511	510	510	508	507	507
IPP	85	85	71	71	71	71	71	71
Other								
Local sales	190 986	178 284	182 379	181 831	181 751	180 652	180 424	179 758
International (SAE)	15 095	12 890	12 054	11 748	10 876	10 815	10 815	10 815
Total Eskom Sales	206 081	191 174	194 433	193 579	192 627	191 467	191 238	190 573

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA
Private Bag X67, Pretoria 0001
REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA

3.3 Uncertainty of the sales volume forecast

The demand for electricity is highly uncertain at the best of times. The post Covid-19 sales forecast anticipates elements of a slow recovery in the global economy and mostly subdued commodity prices, while local growth is expected to trail behind that of other emerging economies. Eskom sales is also expected to be negatively impacted by the gradual transition to alternative energy sources. The figure below depicts the sales forecast indicating the level of possible gains and losses as identified in the tables to follow.

FIGURE 6: TOTAL LOCAL SALES SHOWING THE CONE OF UNCERTAINTY



The tables below illustrates and quantifies the various upside and downside factors associated to the above sales forecast over the MYPD period. The factors are justifiable, given the volatile and unpredictable nature of elements largely beyond Eskom's control. The risks are also graded by probability and assigned a status of high, medium or low.

TABLE 10: POSSIBLE DECREASE IN ENERGY CONSUMPTION

Sales in GWh								
Downside Factor	Possible Decrease explanation	Probability	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
IPP Impact	Alternative IPP energy used by Munics	High	(1 042)	(1 060)	(1 443)	(1 451)	(1 458)	(1 477)
Ferrochrome Sector	Weaker global demand/lower furnace utilisation	Med-High	(460)	(460)	(565)	(543)	(543)	(460)
Ferrosilicon Sector	Decline in orders	Med-High	(47)	(47)	(48)	(47)	(47)	(47)
Ferromanganese Sector	Lower commodity prices / strong Rand	Med-High	(104)	(155)	(158)	(155)	(155)	(155)
Steel Sector (Incl. Stainless)	Weaker commodity prices / strong Rand	Med-High	(155)	(145)	(155)	(166)	(181)	(182)
Gold Sector	Earlier shaft closures / lower Gold price	Med-High	(102)	(52)	(52)	(52)	(52)	(52)
Platinum Sector	Project delays / downscaling	Med-High	(420)	(502)	(563)	(573)	(601)	(623)
Traction Sector	Sluggish economy & vandalism	Med-High	(56)	(60)	(70)	(75)	(84)	(93)
Temperature & Rainfall	Warmer than average / higher rainfall	Med-High	(650)	(650)	(650)	(650)	(650)	(650)
Eskom Supply Constraints	Load Shedding / Curtailment / Reductions	Med-High	(1 600)	(1 568)	(1 537)	(1 506)	(1 476)	(1 446)
Increased Co-gen	Higher co-gen levels (Sasol, Kelvin + Other)	Med-High	(550)	(550)	(550)	(550)	(550)	(550)
Industrial Action	Labour action & community protests	Med-High	(600)	(600)	(600)	(600)	(600)	(600)
Economic Growth	Lower than expected growth post Covid-19	Med-High	(1 122)	(598)	(224)	-	-	-
Covid-19 Pandemic	Shutdowns from re-emergence of virus	Med-High	(2 243)	(748)	(374)	-	-	-
Aluminium Sector	Decline of revised NPA Framework	Low-Med	(10 282)	(10 282)	(10 311)	(10 282)	(10 282)	(10 282)
Total Downside Impact			**(19 434)**	**(17 475)**	**(17 299)**	**(16 650)**	**(16 679)**	**(16 617)**

The largest risk presents in the Aluminium sector at a possible loss of 10.2 TWh. It is reported that an Aluminium smelter that was on a commodity linked pricing deal (NPA), which has expired on 31 July 2020 would be rendered unsustainable if it was to be subjected to standard Eskom tariffs.

The Covid-19 pandemic is a further notable risk of 2.2 TWh, given the unknown trajectory of the virus as well as the efficacy of possible vaccines. The impact of IPP sales to Municipalities is another key factor which has the capability to reduce sales by 1 TWh. Further risks include that of load shedding (1.6 TWh), lower than anticipated economic growth (1.1 TWh) and warmer than average winter temperatures (0.6 TWh). Since customers are exposed to a multitude of external factors, smaller risks are also inherent at sector level and contribute the remaining of the above risk quantity.

TABLE 11: POSSIBLE INCREASE IN ENERGY CONSUMPTION

			Sales in GWh					
Upside Factor	**Possible Decrease explanation**	**Probability**	**Projection FY2022**	**Application FY2023**	**Application FY2024**	**Application FY2025**	**Post Application FY2026**	**Post Application FY2027**
Ferrochrome Sector	Improved trading conditions/Re-opening of Mogale Alloys	Low-Med	813	813	760	771	771	813
Ferrosilicon Sector	Improved commodity prices / weak Rand	Low-Med	114	114	113	114	114	114
Ferromanganese Sector	Higher commodity prices/Re-opening of South32 Meyerton	Low-Med	343	280	276	280	280	280
Steel Sector (incl. Stainless)	Higher steel demand/re-opening of Saldanha Steel	Low-Med	1 184	1 197	1 183	1 170	1 152	1 150
Gold Sector	Higher than average Gold price / weaker Rand	Low-Med	147	78	51	46	48	43
Platinum Sector	Low probability expansions / weak Rand	Low-Med	165	167	169	169	170	170
Traction Sector	Infrastructure repair & higher economy	Low-Med	162	160	152	149	142	136
Temperature & Rainfall	Colder than average / lower rainfall	Med-High	1 040	1 040	1 040	1 040	1 040	1 040
Load Shedding / Curtailment	Lower supply constraints	Med-High	150	190	240	290	340	390
Short-Term Incentives	Approved short term pricing incentives(Smelters)	Med-High	300	300	300	300	300	300
Economic Growth	Faster than expected growth post Covid-20	Low-Med	897	479	179	-	-	-
Lower Co-gen	Lower levels of Co-gen	Med-High	495	495	495	495	495	495
Aluminium Sector	Full Capacity with new NPA	Low	-	-	-	-	-	-
Total Upside Impact			**5 810**	**5 312**	**4 959**	**4 824**	**4 851**	**4 931**

The figure in the table above highlights the upside or positive movement of sales in relation to the MYPD5 forecast. This refers to a potential sales increase that could arise, should certain conditions materialise.

A key factor in this regard is that of colder than average winter temperatures. This implies that additional sales of 1 TWh could transpire, should colder winter temperatures emerge over the applicable years.

A further favourable factor lies with the large industrial smelters. As previously stated, several large smelters have closed and downscaled over the past few years. There remains a total opportunity of up to 2.4 TWh, should the relevant market conditions improve in the short term.

Higher than expected economic growth is expected to yield 0.8 TWh additional in the first year, while lower levels of customer co-generation could see 0.5 TWh additional.

3.4 Sales forecasting approach

There are various different influences on customers' current and future electricity consumption determined by individual customers' need for electricity and substitutes to taking supply from Eskom. To practically capture this complex dynamic, the Eskom forecasting encapsulates differing sales assumptions by customer types that are the high sales and lower-sales end users. For high-sales volume customers, the sales forecasting assumptions comprises individual customer planning inputs. For the lower consumption customers, the sales forecast is informed by historical trends, weather and relevant economic indicators.

Consequently, volume changes in the high-sales customer category requires the application of an individual bottom-up approach, so as to consider specific sales drivers that include individual business plans, responses to price elasticity of demand (if any), commodity prices, and the consideration of external economic factors.

The forecasting of international sales adopts the individual approach given the country specific drivers and the fact that the sales are exported.

Municipalities purchase in bulk from Eskom, distributing to industrial and commercial sectors with a greater part of supply to residential end users. Eskom bulk sales to municipalities differ from one municipality (or metro) to the next, as each municipality's purchase profile shaped by their individual customer-mix. Eskom therefore uses a combination of forecasting methodologies combining an individual consultation with the municipality, in line with the respective local government development plans, as Municipalities there are various aspects that impact their respective electricity consumption profiles.

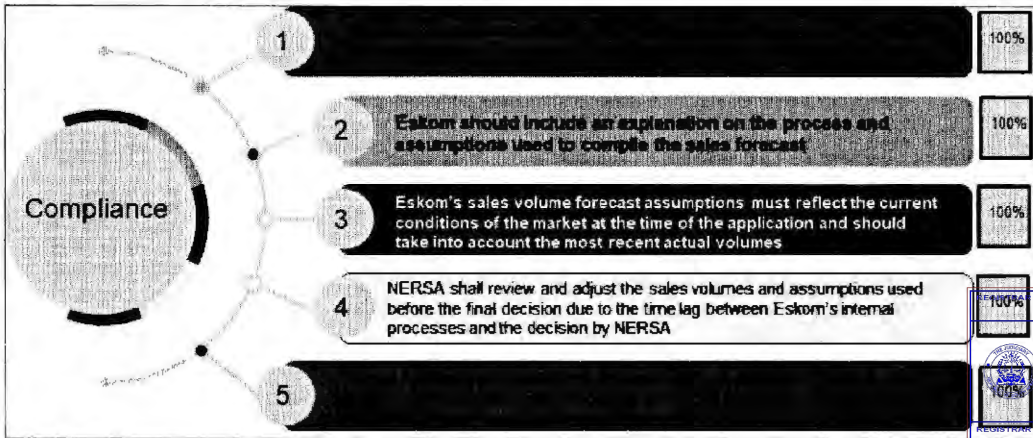
For the residential and commercial sectors, historical trends, weather and economic indicators are the primary indicators that inform the sales forecast.

3.5 Sales forecasting process

A five-step process, as depicted in the figure below, is followed to forecast Eskom electricity sales. This process includes the compilation of a six-year monthly detailed forecast with the last four years of the period at an annual level using trends per sector. As the diagram depicts the Sales forecast is a bottom up derived forecast.

Each of the nine Eskom provincial operating units concentrate on their top customers in detail while the other customer sectors is forecasted at summary level to derive a 6 year projection per month with a further 4 years of annual numbers. Detailed analysis and rigorous validation processes follow to ensure consensus that the derived forecast is the most likely scenario given the current information available.

FIGURE 7: AREAS OF COMPLIANCE IN PROVIDING THE MYPD FORECASTD SALES



Each Eskom Distribution operating unit (OU) tend to the customers that account for 80% of that OU's revenue individually in great detail. Engaging the customer executives and obtaining applicable information from the customers while balancing this view with sectoral trends, the expected economic climate and any other relevant information. It is clarified at this stage, the proposed price increase that NERSA will determine is not known.

4 Energy Losses

Eskom Distribution Energy loss is defined as the difference between energy purchased (measured at the Transmission main substations and at Independent Power Producers plants) and energy sold to all Distribution customers (measured or estimated). This includes both technical energy losses (also known as copper and iron losses) and non-technical energy losses. It excludes non-payment or bad debt.

4.1 Energy losses benchmark

The proposed distribution losses targets in this forecast are well within the regulator's (NERSA) benchmark of 10% as stipulated in the regulators cost to supply framework Section3.2.1.1 a) (i). The cost of supply framework states that utilities should manage distribution losses within the tolerable range of 5 – 12%.

4.2 Energy losses forecast

The energy losses volume and percentage are derived from the purchases (from Transmission, IPPs, International Imports and distribution owned generators) and sales to customers are shown in the equation below, as the difference between purchases (input) and the sales (output):

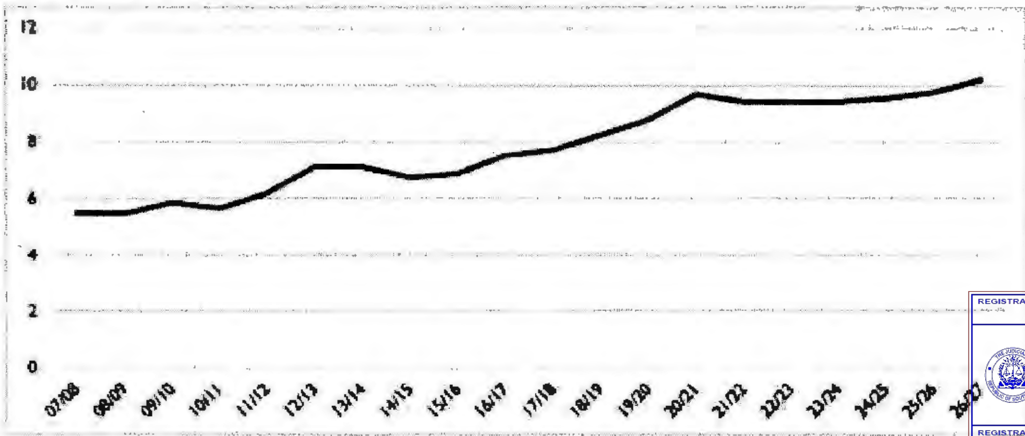
- Losses [GWh] = Purchases [GWh] – Sales [GWh]

The % percentage losses is also expressed as a ratio of losses volume to the purchases volume:

- $\% \, Losses = \frac{Losses\,[GWh]}{Purchases\,[GWh]}$

The losses forecast is based on a trend analysis of the past performance. The actual percentage energy losses recorded for the FY 2008 to FY2021 and the forecast for FY2022 to FY2027 is reflected on figure below.

FIGURE 8: ENERGY LOSSES TREND



The proposed forecast is informed by the historical performance of the past period on which data analysis was performed. Data analysis of the historical performance was performed and the sales forecast for the application period was performed. This resulted in the losses volume and percentage forecast as given in the table below.

TABLE 12: PROPOSED ENERGY LOSSES TARGETS

Distribution Losses	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
GWh	18 436	19 190	19 046	18 971	18 919	19 113	19 554	20 414
%	8.8%	9.7%	9.5%	9.4%	9.4%	9.6%	9.8%	10.2%

The table above depicts the losses figures, both in volume and percentage that Distribution is applying for.

4.3 Forecast assumptions

There are various factors drawn from the different customer categories forecast are assumed to continue to influence the losses forecast in the following way.

- The negative forecasted growth of sales to high voltage customers, which are redistributors, industrial and mining, will result in higher percentage of losses, and not so much to the volumes as these customers have low loss-factors. The historical furnace load reduction in winter is expected to continue and reduce base of high voltage sales and purchases, thus increasing the losses percentage.
- Residential customers due to our electrification program, are expected to grow. The customers are connected in low voltage as such, contributing to an increase in volume losses.

- The increasing trend is also influenced by the factors discussed in Section 4.4. A number of initiatives have been implemented to reduce the losses.

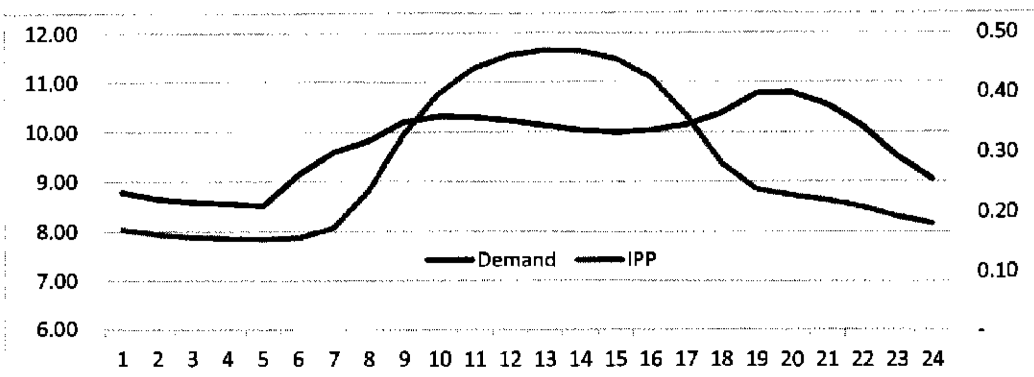
4.4 Factors impacting the losses forecasts

Distribution monitors energy losses continuously and has embedded within its operations various interventions aimed at addressing the challenge. While various losses reduction interventions have been implemented, the business has realized varying levels of success across different customer sectors.

The increase in total distribution energy losses is attributable to the following:

- Preliminary analysis suggests that there is an increase in the non-technical component of losses (theft) due to prevailing economic conditions. Theft is not limited only to the residential customer sector, but across different customer sectors.
- The ageing nature of distribution networks, which are often constrained and overloaded, results in an increase in the technical component of energy losses.
- Increase in IPP operations provides additional technical losses: Independent Power Producers (IPP) are predominantly renewables in nature. Renewable IPP's locations are restricted by the availability of the natural resource be it solar, wind or hydro. This will mostly not be as per the load requirement.

FIGURE 9: TYPICAL DAILY PROFILE OF RENEWABLE IPP AGAINST DISTRIBUTION DEMAND



The profiles of renewable IPPs are not matching the load profile (see figure above). The IPPs, which are mostly renewable, are not to be optimally positioned, for Distribution load as the IPP are established at the primary source solar or wind. The IPP energy is available during time periods when the local demand is lower than the supply, with energy being evacuated back to transmission grid to be consumed elsewhere. During this process, additional technical losses are incurred in the Distribution network.

4.5 Energy losses management

Eskom Distribution monitors energy losses continuously and has embedded within its operations various interventions aimed at addressing the energy losses. These interventions aim to address losses from a technical, commercial, and social perspective. Some of these interventions are:

- Reconciliation of the energy delivered and energy sold (i.e. energy balancing) at the reticulation feeder level in order to prioritize high loss feeders for normalization
- Auditing and repairing of faulty customer meter installations
- Disconnection of illegal connections, meter tampers and imposition of penalties (tamper substantiate with fines)
- Improvement of process and data anomalies correction
- Estimation and recovery of revenue for historic unaccounted energy where tampered, faulty or missing metering installations are encountered
- Revision of Supply Group Codes on prepaid meters to prevent the use of illegal prepaid vouchers
- Implementation of technologies in the form of smart/split meters with steel enclosures to prevent access to the meter
- Customer education, social mobilization and partnership campaigns to drive behavior change
- Investigations and subsequent prosecution of criminals/syndicates perpetrating electricity theft through the sale of illegal prepaid vouchers and providing illegal electrification and meter tampering services

Eskom is to continue with the various losses reduction interventions.

4.6 Conclusion on Distribution energy losses

The proposed losses percentage (9.4%, 9.4% and 9.6%) are within the NERSA losses benchmark of 5 -12%. The energy losses interventions implemented have assisted in containing energy losses growth and with the increasing number of IPPs connected to Distribution network it is anticipated that the technical losses component from a forecast perspective to increase.

5 Regulated Asset Base, Return and Depreciation

The Regulatory Asset Base (RAB) is defined as assets of the regulated business that is used or usable in the production of the regulatory services. The MYPD methodology specifies that the RAB of the regulated business operations must only include assets necessary for the provision of regulated services based on the net depreciated value (residual value) of allowable fixed assets necessary to allow the utility reasonable return to be financially viable and sustainable while preventing unreasonable price volatility and excessive sustainability.

Regulatory depreciation and return on the RAB provides the regulatory mechanisms under which capital investment costs are recovered on a cost reflective basis over the course of its regulatory economic life. Hence capital expenditure is not a separate cost item in the revenue regulatory formula.

In this revenue application, Eskom is required to apply for the following:

- Depreciation on the commissioned assets, in accordance with the method prescribed by the MYPD methodology. Depreciation is calculated on revalued assets as at 31 March 2020, assets commissioned since 31 March 2020 and asset purchases.
- Return on assets is calculated on all assets including work under construction and working capital, at a rate determined by NERSA.

The relevant aspects of the allowed revenue, in terms of the MYPD methodology considered here are highlighted:

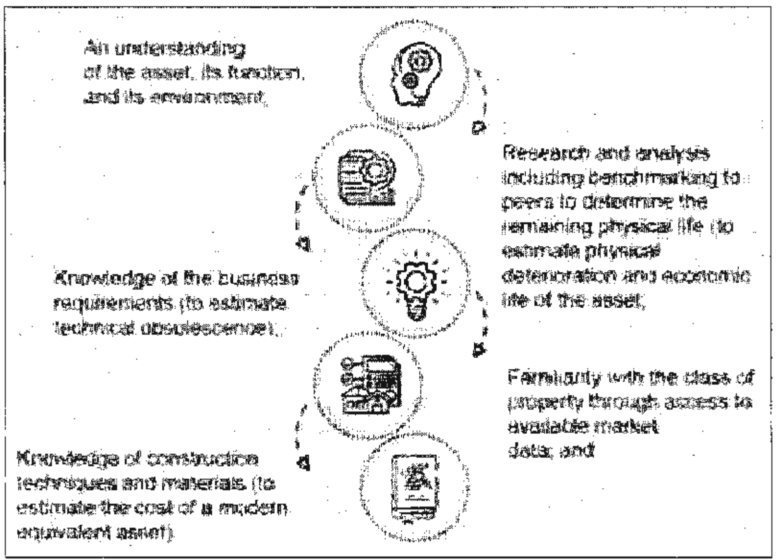
$$AR=(RAB \times WACC)+E+PE+D+R\&D+IDM \pm SQI+L\&T \pm RCA$$

The ERA and the Electricity Pricing Policy (EPP) require the recovery of efficient costs and earning a fair return on capital. The EPP and the MYPD methodology require that assets are valued at its Modern Equivalent Asset Value (MEAV). In accordance with the MYPD methodology, Eskom has undertaken a revaluation of all completed assets used in the generation, transmission and distribution of energy as at 31 March 2020. It should be noted that the process followed requires an independent assessment of the value of the RAB. Eskom's actual capital expenditure is not considered when this RAB valuation is undertaken. It is viable benchmarks, for the depreciated replacement costs that are considered in arriving at the valuation of RAB as at 31 March 2020.

The RAB valuation was undertaken by an independent entity that has international experience in the realm of asset valuation for large infrastructure companies. As required by the MYPD methodology, the determination of the regulatory asset base value is based on the costs to replace these assets (i.e. Modern Equivalent Assets Valuation (MEAV)) and adjusted for the remaining life and any relevant forms of obsolescence. This valuation has been undertaken in accordance with the guidelines and requirements of the International Valuation Standards. The basis of the valuation was the Eskom fixed asset registers and comparisons were made with market data for actual construction cost of similar assets. This valuation exercise included site visits where samples of the physical assets were performed. The site visits had to be minimised due to the restrictions of the Covid-19 pandemic.

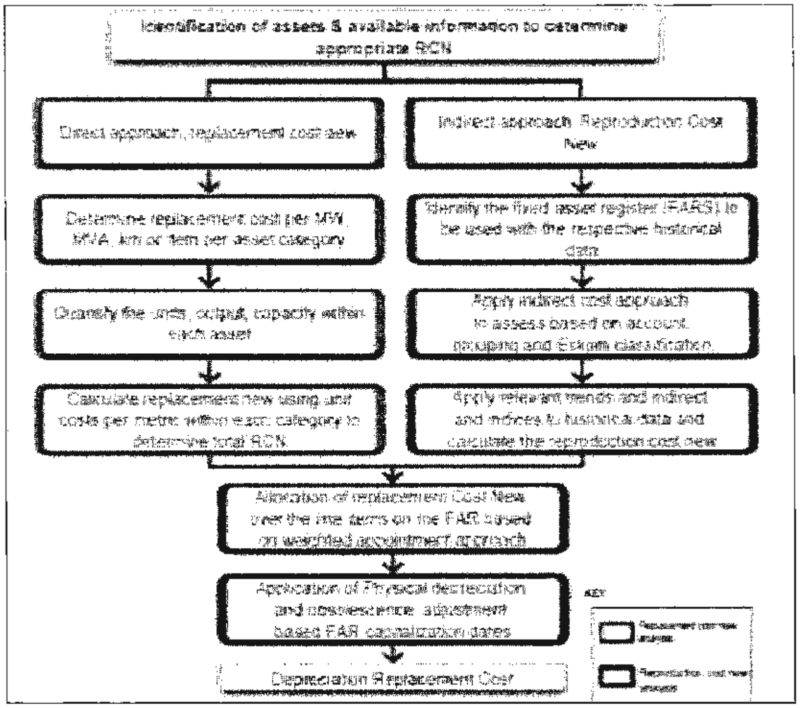
In determining the depreciated replacement cost, the independent consultants ensured that the following key elements were undertaken.

FIGURE 10: VALUATION KEY STEPS



The International Valuation Standards Charter defines a Modern Equivalent Asset as "An asset which provides similar function and equivalent utility to the asset being valued, but which is of a current design and constructed or made using current materials and techniques." The MEAV approach is synonymous with the Cost Approach or Depreciated Replacement Cost approach. The DRC was determined through the application of the cost approach methodology, which is a recognised approach for the valuation of specialist assets which are not regularly traded. The cost approach methodology includes the identification of the estimated new replacement cost of assets, which is then adjusted to reflect physical, and functional obsolescence. The cost approach is summarised in the figure below.

FIGURE 11: VALUATION METHODOLOGY



The Eskom assets have been valued based on a Depreciated Replacement Cost (DRC) method. The DRC method is a form of cost approach that is defined as:

"*The current cost of replacing an asset with its modern equivalent asset less deductions for physical deterioration and all relevant forms of obsolescence and optimisation.*"

The DRC method is based on the economic theory of substitution and it involves comparing the assets being valued with another. However, DRC is normally used in situations where there is no directly comparable alternative. The comparison, has to be made with a hypothetical substitute, also described as the modern equivalent asset (MEA).

The underlying theory is that the potential buyer in the exchange would not pay any more to acquire the asset being valued than the cost of acquiring an equivalent new one. The technique involves assessing all the costs of providing a modern equivalent asset using pricing at the valuation date.

In order to assess the price that the potential buyer would bid for the actual subject asset, valuation depreciation adjustments have to be made to the MEA to reflect the differences between it and the subject assets.

These differences can reflect obsolescence factors such as the physical condition, the remaining economic life, the comparative running costs and the comparative efficiency and functionality of the actual subject assets.

The asset values in the Regulatory Asset Base are therefore not shown at the new cost to replace them but at their depreciated replacement cost. For example, if it costs R1bn to replace an asset at the end of March 2020 which has two years remaining life out of a total useful life of 25 years, the depreciated replacement cost at the end of March 2020 would be R80 m (i.e. R1bn x 2/25). This valuation forms the basis of the RAB application as shown in the table below.

TABLE 13: REGULATORY ASSET BASE (RAB) SUMMARY

Regulatory Asset Base (R'm)	Decision FY2021	Decision FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Depreciated Replacement Costs (DRC)	46 579	39 611	100 187	93 208	86 527	80 149	74 035
Assets Transferred to Commercial Operations	20 751	25 538	18 477	22 218	27 553	40 482	45 111
Work Under Construction (WUC)	3 930	2 573	7 882	13 295	15 397	8 599	8 562
Net Working Capital	18 285	20 839	21 454	23 971	26 146	29 184	31 785
Assets Purchases	1 308	1 357	975	1 148	1 248	1 099	982
Assets funded upfront by customers			(14 127)	(14 244)	(14 338)	(14 406)	(14 415)
Closing RAB	**90 853**	**89 917**	**134 849**	**139 596**	**142 534**	**145 107**	**146 059**

5.1 Regulatory Asset base components:

In accordance with the MYPD methodology, the regulatory asset base is comprised of the following:

- Depreciated replacement cost assets: these are assets as per the March 2020 asset valuation. The valuation includes assets already in use in the distribution of electricity as at 31 March 2020. All other assets in construction are not included in the valuation but rather in the WUC.
- Assets transferred to commercial operations: This refers to distribution assets transferred into Commercial Operation subsequent to the 2020 asset valuation. Once commissioned, these assets are then depreciated by dividing the cost of the asset over the number of years that the asset is to be used for i.e. the useful life of the asset.
- Work under construction (WUC): In accordance with the MYPD methodology, for assets that constitute the 'creation of additional capacity', the capital project expenditures or WUC values (excluding IDC) incurred prior to the assets being placed in Commercial Operation (CO) are included in the RAB and earn a rate of return.
- Net working capital: This includes trade and other receivables, inventory and future fuel less trade and other payables.

- Asset purchases: all movable items that are purchased and ready to be used are included in this category e.g. Equipment and vehicles, production equipment etc.

5.2 Depreciated replacement costs

The extract of the DRC from the valuation report is shown in the Table below. The valuation report excludes interest during construction (IDC) due to the overnight cost being used to determine the MEAV. Overnight cost is defined as the cost of a construction project if no interest is incurred during construction as if the project was completed overnight.

TABLE 14: EXTRACT FROM INDEPENDENT VALUATION REPORT

Distribution (Dx)	Cap Cost (ZAR Millions)	NBV (ZAR Millions)	NBV in Scope (ZAR Millions)	Final RCN (ZAR Millions)	Physical Depreciation (ZAR Millions)	DRC (ZAR Millions)
Telecommunications (6000)	313	12	12	1.074	(1.032)	42
Distribution Plant (21000)	93.715	55.768	55.768	321.886	(199.072)	122.814
Distribution Electrification Assets (21000)	8.487	663	663	29.150	(24.040)	5.109
Government Funded Electrification Assets (21000)	28.366	19.435	19.435	97.429	(30.035)	67.394
Land	284	284	-	-	-	N/A
Buildings	2.662	2.210	-	-	-	N/A
Sub total	**133.847**	**78.372**	**75.876**	**449.538**	**(254.179)**	**195.359**

The Capital Cost (Cap Cost), Net Book Value (NBV), and Net Book Value in Scope (NBV in Scope) was in accordance with the Eskom's fixed asset registers (FARs). The Modern Equivalent Asset Value (MEAV) was determined using the Overnight Cost methodology and assigned the costs on a "like for like" basis based on the nature of the subject assets to arrive at the Final Replacement Cost New (RCN). The Final RCN was adjusted for physical depreciation as per the age profile of the assets. The Final RCN less Physical Depreciation was then adjusted for Technical Obsolescence based on the performance of the assets in comparison to a defined performance standard, to arrive at the Depreciated Replacement Cost. The Depreciated Replacement Cost being "the current cost of replacing an asset with its modern equivalent asset less deductions for physical deterioration and all relevant forms of obsolescence and optimisation.

5.3 Work under construction (WUC)

In terms of the MYPD methodology the criteria for inclusion of WUC into the RAB is for those assets that are for the creation of additional generation, transmission and distribution capacity and are defined as follows:

- **Expansion** – this is capital expenditure to create additional capacity to meet the future anticipated energy demand forecast.

- **Upgrade** – this is capital expenditure incurred to ensure that the current and future energy demand forecast is met.
- **Replacement** – this is capital expenditure to replace assets that have reached the end of their useful life in order to continue meeting the current demand.
- **Environmental legislative requirements** – this is capital expenditure incurred to ensure that the licensing condition is maintained thereby continuing to meet the current energy demand forecast.

A WUC in essence refers to the capital expenditure being undertaken and meets the criteria referred to above for inclusion in the RAB. In terms of the MYPD methodology, the WUC balance is required to earn a return on assets but is not depreciated until assets are transferred to Commercial Operation (CO). Only upon commercial operation (CO) do these assets incur depreciation costs.

The transfers to CO from WUC are grouped into the categories of substations and lines. For Distribution, these new assets are depreciated on a normal useful life of 30 years for substations and 40 years for lines.

5.4 Depreciation

The depreciation is the cost of usage over the life of the asset. This is generally a proxy for the recovery of the capital portion of the debt incurred. As is required by the MYPD methodology, the annual depreciation allowance is determined by dividing the cost of the asset by the estimated useful life of that asset. The table below reflects the revenue related to depreciation for the MYPD5 period.

TABLE 15: DEPRECIATION

Depreciation (R'm)	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Depreciated Replacement Costs (DRC)	7 278	6 980	6 680	6 378	6 114
Assets Transferred to Commercial Operations	600	1 039	1 251	1 766	2 305
Assets Purchases	244	287	312	275	245
Assets funded upfront by customers	(724)	(767)	(817)	(871)	(930)
Total	**7 397**	**7 539**	**7 426**	**7 548**	**7 735**

Depreciation on assets as per the FY2020 valuation is computed by dividing the depreciated value of the assets over the remaining life of the respective assets as reflected at the end of March 2020. All subsequent transfers to commercial operation post 31 March 2020 are depreciated over the normal useful life.

5.5 Assets excluded from RAB

Depreciation as shown in the table above includes assets that are funded via upfront capital contributions. In terms of the MYPD methodology these assets do not earn a return on assets and their depreciation is not included in the revenue requirement. The total assets and the depreciation have therefore been reduced by the values as shown in the table below to exclude such assets.

TABLE 16: ASSETS FUNDED VIA UPFRONT CONTRIBUTIONS

Regulatory asset base (R'm)	Decision FY2021	Decision FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Opening balance	(32 375)	(29 292)	(14 108)	(14 127)	(14 244)	(14 338)	(14 406)
Inflation	-	-	-	-	-	-	[illegible]
Transfers to Commercial Operations (CO)	(643)	(704)	(743)	(883)	(910)	(939)	(939)
Depreciation	3 726	3 990	724	767	817	871	930
Closing RAB	**(29 292)**	**(26 006)**	**(14 127)**	**(14 244)**	**(14 338)**	**(14 406)**	**(14 415)**

The objective of tracking these assets as a separate asset class (as shown in the table above) is to ensure transparency; therefore both the RAB and the depreciation are reduced accordingly.

In distribution, self-build assets of R 10 404m and DMRE funded electrification assets of R69 322m are excluded from the DRC as at 31 March 2020. Self-build assets are defined as assets built by 3rd parties and then handed over to Eskom to operate and maintain.

5.6 Return on assets

The WACC, as determined by NERSA for the MYPD period is used as a comparison for the cost reflective return on assets. It is likely that this value has increased since then. However, it allows for a conservative estimate, as Eskom migrates towards the cost reflective level.

The return on assets are being phased to allow for the smoothing of the tariff as shown in the table below. This is the phasing that Eskom has to make to allow the average price of electricity to migrate towards cost reflective tariffs. In the absence of such a phasing, the price increase being requested will be significantly higher. This migration is accompanied by risks which need to be managed. It is unfortunate, that further burden is required to be applied on the fiscus. In essence the subsidy provided to all consumers is continued to be provided for a longer period.

TABLE 17: RETURN ON ASSETS

Return on Assets	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Closing RAB (R'm)	134 849	139 596	142 534	145 107	146 059
Real pre-tax WACC %	7.1%	7.1%	7.1%	7.1%	7.1%
Cost Reflective RoA (R'm)	9 574	9 911	10 120	10 303	10 370
RoA Applied for RoA %	-1.99%	0.69%	0.87%	1.65%	3.04%
RoA Applied for (R'm)	(2 685)	966	1 244	2 387	4 433

nA.

6 Revenue Related Information – Operating Costs

The Licensee's operations spans across South Africa to service all customers ensuring that the networks are available for continued electricity supply and revenue streams. The Licensee operates out of 5 operating clusters consisting of 27 operating zones to manage 306 customer network centres (CNCs).

The Licensee's operating cost (OPEX) components in this application consist of employee benefits, maintenance, other costs and impairments. The table below reflects the Licensee operating costs.

TABLE 18: DISTRIBUTION OPERATING AND MAINTENANCE COSTS (R'M)

Operating expenditure (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Employee benefit costs	11 414	11 560	11 862	12 032	12 545	13 158	13 827	14 699
Maintenance	3 399	3 728	4 940	5 184	5 418	5 731	6 045	6 347
Other operating expenses	3 821	3 747	4 757	5 056	5 363	5 596	5 631	5 923
Corporate Overheads	2 637	2 956	2 475	2 448	2 564	2 382	2 561	2 683
Other Income	(592)	(427)	(478)	(509)	(530)	(534)	(536)	(536)
Total operating expenditure	**20 679**	**21 564**	**23 556**	**24 211**	**25 360**	**26 333**	**27 528**	**29 116**
Corporate Overheads: portion excluded from revenue requirement		(57)	(266)	(245)	(270)	(289)	(272)	(272)
Total operating expenditure	**20 679**	**21 621**	**23 290**	**23 966**	**25 090**	**26 044**	**27 256**	**28 844**

6.1 Employee expenses

Distribution employees are engaged in service to the customer, operating and maintaining the electrical network and associated infrastructure thereby ensuring compliance to the license conditions whilst providing sustainable supply of electricity to all South Africans. The table below provides a summary of employee expenses and headcount.

TABLE 19: DISTRIBUTION EMPLOYEE HEADCOUNT

Employees expenses and Headcount	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Employee expenses (R'm)	11 414	11 560	11 862	12 032	12 545	13 158	13 827	14 699
Head count	17 453	17 594	17 604	17 520	17 422	17 314	17 714	17 714

Eskom has consistently benchmarked the salaries and related benefits of all levels of employees to ensure alignment to the market. The Licensee has an employee complement of 17 594, with 7% of employees at managerial level and 93% of employees within operations. Employee benefits costs are influenced by three main factors: Staff numbers; Employee benefits increases and Level of remuneration.

The employee numbers in this application includes a planned employee reduction which is primarily based on natural attrition and the implementation of efficiency improvement initiatives to provide a transitional path without disrupting effective service and operations to customers.

The CAGR for the period FY2022 to FY2025 for employee expenses (manpower costs) is 3.5%, which is below inflation. In alignment with cost reduction objectives, Licensee employee numbers will be contained over the application period.

6.2 Maintenance

Eskom Distribution's maintenance regime includes both preventative and corrective maintenance. Preventative maintenance refers to planned maintenance activities on assets whilst corrective maintenance refers to unplanned or fault activity. The table below summarises the breakdown of Distributions' maintenance costs.

TABLE 20: DISTRIBUTION MAINTENANCE COSTS (R'M)

Total Maintenance Cost (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
High Voltage Networks	168	185	258	285	313	347	382	419
Medium Voltage Networks	306	336	469	518	569	630	695	762
Low Voltage Networks	390	428	598	661	725	804	886	971
Substations	275	302	422	467	512	567	626	685
Vegetation Maintenance	161	176	246	272	299	331	365	400
Wood Pole Maintenance	229	252	352	389	427	473	521	571
Total Planned Maintenance	**1 530**	**1 678**	**2 347**	**2 592**	**2 844**	**3 152**	**3 476**	**3 808**
Unplanned (Corrective) Maintenance	1 869	2 050	2 594	2 592	2 574	2 579	2 569	2 539
Total Maintenance	**3 399**	**3 728**	**4 940**	**5 184**	**5 418**	**5 731**	**6 045**	**6 347**

The objective of maintenance is to ensure that:

- Asset condition is managed over the asset life cycle.
- Regulatory and Statutory requirements are adhered to (Safety, Health and Environment).
- The technical performance KPIs focusing on interruptions and restoration time are in accordance with the agreed performance levels between Eskom and Regulator.

The key drivers for the maintenance expenditure include the following:

- **Environmental and safety consideration :** To ensure safe operation of the network with a minimum impact to the environment
- **Asset Base:** Geographically, the distribution network spans a landscape of approximately 49 107 km of distribution lines, 301 916 km of reticulation lines, and more than 7 734 km of underground cables in South Africa, this represents the largest power-line system in Africa. Based on history the asset base grows by approximately 4% per

annum. This will increase the maintenance requirements in both the preventative and corrective (fault) environments.

- **Network performance:** Networks need to perform in line with design requirements supporting compliance to technical performance KPIs.
- **Quality of service to the customer:** Apart from supply availability, quality of supply parameters (voltage regulation, voltage dips, voltage unbalance etc.) must comply with National Regulator requirements.
- **Sustainability of network infra-structure:** The network infra-structure is aging and with limited capital investment leading to sub-optimal performance of network.

6.2.1 Planned (preventative) maintenance

Distribution maintains the network infra-structure (lines, substations, transformers etc.) as specified in the maintenance standards. The key planned maintenance activities for the different asset classes include:

- Network inspections and defect clearing; Substation inspections and defect clearing; on load tap changer maintenance; breaker and isolator maintenance; power transformer and neutral earthing compensator oil sampling and analysis; substation earthing inspection, testing and remedial work; substation infra-red scanning and remedial work; battery bank and charger testing and maintenance; protection relay testing and maintenance; tele-control testing and maintenance; metering testing and maintenance; ring main unit maintenance; voltage regulator maintenance; and wood pole testing and replacement.

The above activities prescribed in the maintenance standards is to ensure that the asset performs in line with its design intent. This includes frequency of interruptions and functional performance e.g. voltage regulation on on-load tap changers.

Wood pole inspection and replacement of power line wooden poles ensure safety of public and security of supply. Wood pole maintenance is a scheduled maintenance program based on a set cycle (currently 10 years) to effectively manage the inspection and replacement of defective High Voltage, Medium Voltage and Low Voltage wooden poles.

In ensuring the safe mechanical and electrical operation of its power lines, Distribution maintains vegetation on the power line servitudes to meet its environmental obligations. All vegetation posing a risk to the lines or prevents access must be managed without interfering in the natural attributes of the environment in compliance with environmental and safety requirements.

6.2.2 Unplanned (corrective) maintenance

Unplanned maintenance includes identifying, isolating, and repairing faults so that the failed equipment can be repaired/replaced and the system restored to an operational condition within the tolerances or limits established for in-service operations.

The theft of equipment e.g. conductor, pole mount transformers, poles etc. is on the increase specifically in electrification areas. Apart from the negative impact on technical performance, resources are being directed away from preventative maintenance activities to address faults relating to vandalism and theft.

6.3 Other operating costs

Other operating expenses include insurance, fleet and travel costs, security services, telecommunications, safety equipment and general office expenses. Other operating expenses are essential for the Licensee's operations; these costs are contained to within the CPI inflation parameters, to the extent possible. Other operating costs are defined in the table below.

TABLE 21: DISTRIBUTION OTHER OPERATING EXPENSES (R'M)

Other cost operating costs (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Insurance	1 175	1 440	1 528	1 611	1 685	1 774	1 856	1 949
Security cost	502	506	527	550	576	609	658	690
Information technology costs	430	447	457	476	492	517	543	570
Fleet cost	307	155	24	52	68	66	88	92
Facilities cost	423	450	575	635	698	766	810	857
Telecomms	176	165	146	147	147	148	150	157
Materials/Stores expenses	77	53	62	48	50	61	94	99
Contractor expenses	79	(146)	179	130	244	258	237	346
Customer related:								
Vending Commission	448	410	501	537	587	637	674	707
Customer billing related expenses	92	91	127	132	134	135	138	146
Legal Fees & Debt Collection	14	36	32	33	35	37	39	41
Wheeling cost	44	37	56	58	60	63	65	68
Bank Related Costs	19	20	21	22	24	25	26	27
Reconfigure Prepayment meters			84	164	70	81	93	-
IDM cost	26	66	384	433	420	339	64	68
Business related expenses	9	17	54	28	73	80	96	106
Total other cost	**3 821**	**3 747**	**4 757**	**5 056**	**5 363**	**5 596**	**5 631**	**5 923**

The increases in the "Other operating" costs over the MYPD5 control period are generally linked to inflation and fixed in nature. Where possible the Licensee has implemented cost saving measures whilst improving operating efficiencies. The main contributors to the "Other operating" costs are the following:

6.3.1 Insurance

The business must ensure that there is adequate insurance cover is in place to manage its increasing asset base and exposure against insurable incidents such as natural occurrence, theft, vandalism and public liability claims. The market prices for the premium are hugely driven by replacement cost of assets and past claims history. Insurance covers risk beyond the maximum tolerance levels for the business.

6.3.2 Security cost

Many of the Distribution sites are designated national key points which in terms of legislation require these assets and people to be safe guarded. There has been an increase in theft and vandalism of equipment which warrants the need to safe guard assets for continuity of operations. Security related activities are to safe guard assets, property and employees.

6.3.3 Information technology costs

Information management systems are key to the current and future business operations to support improvement in efficiency, productivity and decision making. The vastness and complexity of network infra-structure requires a number of integrated management systems for network management, outages, dispatching and customer interface and interaction. The information systems enable optimal and efficient network operating, optimal customer billing and revenue collection. The changing customer needs necessitate investment in digital platforms which require continued maintenance to support delivery of the desired customer experience and service delivery.

6.3.4 Fleet and Travel cost

The Distribution network infrastructure footprint is across South Africa mainly in deep rural areas. Employees are required to extensively travel to service all customers. This involves operating, maintaining and repairing networks to comply with regulatory and service standards. Key to the cost is employee recoveries of kilometers travelled for business related activities and associated subsistence allowances. The employees are reimbursed at the SARS travel rates and the Eskom policy aligned to National Treasury Directive on cost containment.

6.3.5 Facility cost

The geographical customer spread across the country, accessibility, convenience to the customer and the business value proposition to meet customer expectations required the establishment and maintenance of customer network centres, hubs and local offices in close proximity to the customer locations. These properties are either owned or leased and the business carries all associated servicing costs. The driver of the facility cost relate to rentals, water and lights, rates and taxes and maintenance.

6.3.6 Telecommunications

Telecommunication is core in enabling protection systems of the distribution infra-structure. The network control centers communicate with all the distribution equipment through the telecommunication network to have real time visibility of high voltage field equipment to remotely operate in response to network incidents. The telecommunication networks are used for data transfer from network control center to equipment and from equipment to other equipment for purpose of operational decision making. Over and above the network requirements this infrastructure also enables communication between the call center, resource management center and field staff to address customer and network faults.

6.3.7 Vending commission

The prepaid customer base is served through a network of vending agents located in close proximity through various platforms for ease of access for the customer. Vending commissions are costs paid to the agents that sell electricity on behalf of Eskom.

6.3.8 Customer billing and meter reading expenses

Billed customer meters are read in intervals through meter reading agents to ensure accurate and timeous billing for energy consumed. The meter reading agents are compensated for the actual number of customer meters read at a predetermined rate. The business also incurs costs for the generation of the customer bill and the distribution thereof.

6.3.9 Reconfiguration of prepayment meters

STS is a secure standard (protocol) used to create encrypted tokens by the Online Vending System (OVS) and is issued by the vending outlets from different suppliers. Each Supply Group Code (SGC) is linked to a key revision number (KRN).The current key revision number is 1 since 1993 (base date) and all vending keys have a life span of 30 years.

The Token Identifier is a 24 bit field, contained in STS compliant tokens, that identifies the date and time of the token generation. It is used to determine if a token has already been used in a payment meter. The Token-ID represents the minutes elapsed since the base date of 1st January 1993.

All STS prepayment meters will be affected by Token ID roll over on 24/11/2024. Any tokens generated after this date and utilizing the 24 bit Token-ID will be rejected by the meters as being "old tokens" as the Token-ID value embedded in the token will have reset back to 0.

To address this, all the meters will have to be changed to a new key revision number and a new base date. This means reconfiguring every meter either ourselves or getting our customers to do it.

Failure to implement this project will disrupt electricity service delivery, leading to irate, unhappy customers, which in turn may trigger temptations for meter tampering, illegal connections or illegal electricity purchases. All these will cause revenue loss and also exacerbate non-technical energy losses and social unrest.

TABLE 22: METERS TO BE CODED (MILLION)

Item (reflected in millions)	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Total
Number of meters to be coded	0	2.2	3.2	1.1	6.5

6.4 Other income

In servicing the customer and maintaining the network the business recognises the following categories of other income.

TABLE 23: OTHER INCOME (R'M)

Other income (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Insurance proceeds/recovery	(444)	(283)	(316)	(317)	(324)	(318)	(314)	(314)
Operating lease income	(7)	(11)	(9)	(9)	(9)	(7)	(7)	(7)
Sundry income	(141)	(133)	(153)	(183)	(197)	(209)	(215)	(215)
Total other income	**(592)**	**(427)**	**(478)**	**(509)**	**(530)**	**(534)**	**(536)**	**(536)**

The main contributors to the "Other income" are the following:

- **Insurance proceeds/recovery:** This relates to proceeds received from insurance, for claims submitted for all insurable incidents as covered in the insurance policy.
- **Operating lease income:** This relates to proceeds received from Operating leases.
- **Sundry Income:** Income for the management of the Electrification program from the Department Mineral Resources and Energy and various other sundry income.

7 Arrear Debt - Gross Impairments

Most retail industries face the challenge of non-payment as part of their efforts in collecting the billed revenue from their customers.

In the current economic climate; customers will experience a continued difficult environment as a result of business closures; increased unemployment & other factors resulting them in not paying their accounts; leaving Eskom with the credit risk. Very few retail businesses are immune against such credit default. This is evident from the financial reports and statements issued by retailers including banks that their impairment provisions are significantly increasing given the macroeconomic challenges presented by COVID-19; rating agency downgrades; high unemployment and very low economic growth. Eskom is no exception; and despite the rigorous credit management processes we employ; credit risk will remain part of our operational cost.

7.1 Percentage impairment applied for

Eskom has limit its impairment application to 2% of revenue; despite its current actuals being higher than 4%; and despite the fact of an increase in risk due to the tougher economic conditions on the customer. This limitation of 2% will result in more than R4.7bn of projected impairment costs not being included in our submission in order not to burden the customer with Eskom's debt collection challenges especially in the Municipality sector.

A 2% impairment equates to a collection level / payment level of 98% of all billed revenue.

In the previous decade; payment levels of 99% were achieved by Eskom; hence a 0.5% impairment application was applied for. However, with the struggling SA economy; increase in debt levels of the average South African consumer; and municipalities struggling to be financially sustainable; a 0.5% impairment (99.5% payment level) can't be considered as a realistic application for prudent costs.

In instances where Eskom is prohibited from executing its credit management processes in full (for example: political pressure; litigation preventing Eskom from applying for recovery of outstanding debt in accordance with the Promotion of Administrative Justice Act (PAJA), etc.), this results in additional arrear debt. From a prudency point of view, this indicates that certain factors are beyond Eskom's control.

The 2% debt impairment level of revenue application assumes significant improvements in the Distribution debt trajectory compared to the current performance; despite the higher risk profile of the average consumer and the deteriorating financial state of some municipalities.

7.2 Debtors & gross impairment

Eskom is managing the payments from small power users (SPU), large power users (LPU) and Top Customer sector reasonably well, with payment levels greater than 99% for most of the financial years.

Only a small portion of Eskom's customer base is contributing to the increase in the overdue debt. During the last few years the overdue debt increased significantly for mainly municipalities and Soweto debtors.

7.2.1 Municipalities

The municipal overdue debt has increased significantly from R13 570m (FY2018) to R35 524m (FY2021). This equates to annual growth in overdue debt of between R7bn – R8bn per annum.

Eskom continues to execute its municipal debt management strategy to ensure maximum collections from non-paying municipalities. In the recent past, Eskom has had to resort to the Courts to enforce contractual credit control measures. However, arising out of a judgement handed down by the Supreme Court of Appeal, our collection process has been revised to utilise the provisions of the Intergovernmental Relations Framework Act. This has been found to significantly impact the time to enforce the contractual commitments made by Municipalities. Eskom understands that NERSA has approved a process to address the Municipalities not meeting their license conditions in this regard.

It is acknowledged by various stakeholders that the key reason for non-payment is due to the systemic failures within municipalities. To address the systemic issues within municipalities pertaining to electricity distribution that are leading to the non-payment, Eskom is advocating an Active Partnering solution whereby Eskom supports municipalities with distribution, reticulation and revenue collection services. We are promoting and pursuing the partnership model to ensure that we create a sustainable Distribution industry and securing the current accounts. The full benefits of this programme will be only be realized over the next 5 - 10 years. It is assumed that all the efforts to recover the municipal debt will result in a decrease in the annual growth rate of the municipal capital portion of the overdue debt, therefore the decrease in the projected gross impairment for municipalities.

7.2.2 Soweto

The turnaround of the culture of non-payment in areas like Soweto are being managed societally as well as technically. Eskom is deploying a technical solution to convert the conventional meters to prepaid meters. Some success has been realized by Eskom experiencing improved prepaid sales as customers are converted to prepaid meters. The full rollout of the solution is anticipated to be concluded by 2023. These conversions therefore reduce further debt growth as conventional sales and impairment will decrease.

Current challenges Eskom is facing includes:

- Resistance by consumers to convert from conventional meters to pre-paid split metering due to the historic culture of non-payment.
- Increase in prepaid customers buying from "Ghost" Credit Dispensing Units.
- Backyard dwellers exacerbating the non-payment culture. Home owners are collecting rent and not paying for services.
- Periodic protest action. Recent protests are from areas where split metering is not installed.

Some of the key turnaround actions being implemented in Soweto and similar township include:

- Converting of all SPU customers to split / smart meters with vandal proof kiosks, as well as electrification of informal settlements.
- Enforce credit management on remaining conventional customers including audits and disconnect bypassed meters, remove illegal connections by collaborating with security services, Public order policing (POPS) and the Johannesburg Metropolitan Police Department (JMPD).
- Intensify communication to encourage a culture of payment and therefore increase the payment level.
- Aggressively roll-out Free Basic Electricity for qualifying residents, in line with the Metro / Municipal criteria.
- Load reduction to protect Eskom employees and equipment
  Change the Supply Group Code and monitor customer buying patterns, and identify zero buying customers through audits.

7.2.3 Top Customers

Top Customers have an excellent payment record, the payment levels were close to 100% for FY2020. However, due to the adverse market conditions, the risk of non-payment by key customers do exist and can have a significant impact on the impairment if just one of the big customers default. Small impairment values have been provided for Top Customers over the MYPD5 period to cater for such risk. A non-payment level of 0.5% to 0.7% per annum has been allowed as part of the Top Customer impairment calculation; which still result in projected payment levels in excess of 99.5% on average over the MYPD5 period.

7.3 Impairment calculation methodology

Eskom is applying the IFRS 15 / IFRS 9 international accounting standards to calculate its impairment. At the core of the IFRS 9 requirement is the need to measure credit impairments in an objective and unbiased manner, using information regarding past events, current conditions and economic forecasts. As per IFRS 15, where the collectability criterion is not met, a "cash basis" approach is followed for the relevant customers with regards to impairment. For the MYPD5 application, the revenue & impairment are shown at gross level (before any accounting adjustments), which is in line with the regulatory accounting principles.

7.4 Gross impairment and customer payment levels

Eskom has limited its impairment application to only 2% of revenue; despite projecting a much higher impairment %. The tables below shows the gross impairment and payment levels per customer segment respectively.

TABLE 24: GROSS IMPAIRMENT (R'M)

Gross Impairment (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027	3 Year MYPD5 Application
Soweto	(1)	298	283	122	-	-	-	-	
Munics	7 912	6 940	7 947	7 251	6 905	6 785	6 701	7 371	
Top Customers	64	70	173	182	202	231	252	277	
Other LPU & SPU	252	253	655	686	761	871	949	1 044	
Impairment cost based on projected overdue debt	**8 228**	**7 561**	**9 058**	**8 241**	**7 868**	**7 887**	**7 902**	**8 693**	**23 996**
Limited to 2% of revenue				(2 575)	(1 356)	(777)	(101)	(151)	(4 708)
Impairment costs applied for	**8 228**	**7 561**	**9 058**	**5 666**	**6 511**	**7 110**	**7 802**	**8 541**	**19 288**

TABLE 25: SUMMARY OF PAYMENT LEVELS PER CUSTOMER SEGMENT

Payment Level per Sector (%)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Munics	92.0%	93.0%	93.1%	94.2%	95.0%	95.6%	96.0%	96.0%
Soweto excl Interest	20.7%	19.3%	22.7%	24.8%				
Top Customers	100.4%	100.1%	99.8%	99.8%	99.8%	99.8%	99.8%	99.8%
Other SPU & LPU	99.9%	99.3%	98.6%	98.7%	98.7%	98.6%	98.6%	98.6%
Total	**96.2%**	**96.4%**	**96.3%**	**96.9%**	**97.3%**	**97.6%**	**97.8%**	**97.8%**

The projected FY2022 payment level of 96.3% is projected to increase to 97.8% in FY2027.

Overdue debt for municipalities is the biggest component of the projected overdue debt increase. The overdue debt is projected to reduce over the MYPD5 application period through improved payment levels and debt reduction strategies which Eskom is embarking on. The summary of the overdue debt is shown in the table below.

TABLE 26: SUMMARY OF OVERDUE DEBT

Overdue Debt (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Top Customers	350	325	414	529	666	826	1 013	1 240
Other Large Power Users (LPU)	359	387	626	877	1 130	1 312	1 563	1 860
Other Small Power Users (SPU)	1 369	1 451	1 636	1 890	2 184	2 368	2 758	3 212
Municipalities	28 042	35 524	43 924	51 924	59 524	66 744	73 964	81 864
Soweto (including interest) *	12 711	8 172	4 323	4 532	4 611	4 702	4 805	4 922
Total	**42 832**	**45 859**	**50 923**	**59 753**	**68 115**	**75 952**	**84 103**	**93 098**

Non-payment of the Munic current accounts excluding interest is currently more than R6bn per annum. Our projection for the application years assume significant improvements in the payment of the current accounts, improving the current R6bn annual non-payment to only R3bn by FY2025, assuming that the major defaulting municipalities significantly improve their current account payments to Eskom; and that our active partnering strategy is yielding the desired results. The table below presents the municipal overdue debt annual growth.

TABLE 27: MUNICIPAL OVERDUE DEBT ANNUAL GROWTH (CAPITAL AND INTEREST SPLIT)

Overdue Debt - Municipalities (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
New Interest raised	3 010	1 310	1 820	2 610	3 370	4 090	4 790	5 250
New Capital debt	5 144	6 172	6 580	5 390	4 230	3 130	2 430	2 650
Total annual overdue debt growth	**8 154**	**7 482**	**8 400**	**8 000**	**7 600**	**7 220**	**7 220**	**7 900**
Total	**28 042**	**35 524**	**43 924**	**51 924**	**59 524**	**66 744**	**73 964**	**81 864**

7.4.1 Additional strategies to mitigate against increase in Impairments

In order to limit the growth of bad debt (impairment) to the Eskom cost base, the company has adopted an approach to limit debt growth whilst enabling electricity sales that includes:

- **Continuous review and enhancement of credit management policies processes:** Eskom's debt and credit management policies, processes and strategies are reviewed on a regular basis to ensure the robust application of our credit controls in order to minimize the impact of escalating debt.
- **Prepaid sales:** Out of Eskom's customer base of 6.7m (March 2021), there are 6.5m prepaid customers (95%). The strategy is to continue to offer new customers the prepaid option and convert existing postpaid customers to prepayment. High risk customers have been identified in all provinces and are converted to prepayment. The conversion process is in progress. A number of large power accounts are also on a payment in

advance option, to reduce the debt risk to Eskom. Prepayment for large power supplies are being investigated and will be supported through smart metering.

- **Deposits / security:** Ensuring an increase in deposits and securities to mitigate future risk by customers identified as potential high risk defaulters. The process to ensure adequate account security across all customer segments will be managed over time to balance this requirement and the unintended consequence of an increase in overdue debt.
- **Innovation:** Eskom has successfully piloted revenue collection for two municipalities. This included the replacement of meters in the municipality, maintenance as well as billing large power customers. The results indicated a reduction in overall municipal losses and an increased cash flow to fund business operations within the municipality. Different operating models are being investigated to ensure viability and sustainability in the future electricity industry.

The service delivery proposals make provision for different working arrangements with municipalities as agreed in the service delivery framework. In extreme cases it may even be requested that Eskom takes over the electricity service delivery within financially distressed municipalities.

The consultative activities have included and will continue to include:

- Engagements with the respective municipal Executives.
- Inter-Governmental Provincial meetings with all the relevant stakeholders.
- Regular National Governmental meetings including Active Partnering.

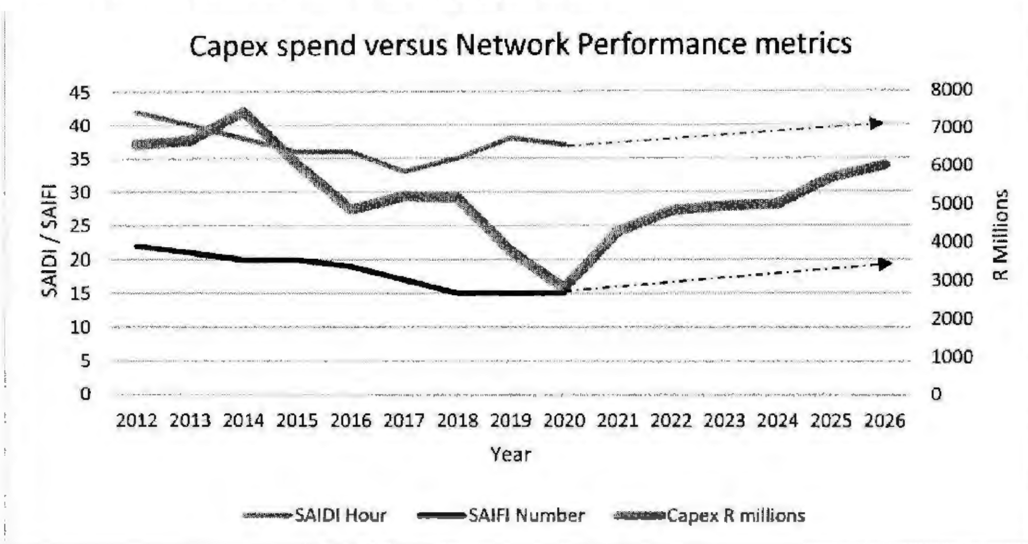
8 Revenue Related Information - Capital Expenditure

Capital investments support the continued productive life of assets and the technical conditions necessary to maintain continued electricity supply to secure revenue streams and improve customer experience.

The application for capital expenditure is required to strengthen and refurbish the Distribution network, to meet future growth requirements, manage the transition of an evolving distribution landscape with increased Distributed Energy Resource integration, whilst allowing the network to maintain current performance standards.

A key priority is to ensure a reliable and sustainable power supply; the Licensee will balance the need for resolving constrained networks whilst providing the supporting infrastructure for maintenance and operating activities. Historically, the Distribution network performance gains are reflective of the investment choices made in the capital projects.

FIGURE 12: HISTORICAL NETWORK PERFORMANCE



The Distribution network capital expenditure is deployed in activities that are based on extensive planning in alignment with the required network performance. A 10-year network development plan informs the capital investment program which supports the forecasted economic load and distributed generation growth nodes.

The capital investment program enables the establishment of the required capacity to meet the future electricity demand and capacity, whilst maintaining acceptable levels of network performance and reliability, and operability. The capital expenditure is also reflective of the capacity of the Licensee to execute the capital program in line with its historical performance.

In compliance to the Grid Code, a network development plan is formulated for the immediate 3-5 year period. The MYPD5 submission and the requested Capital allocation are informed by the 3-5 year development plan. Notable redress is required for capital expenditure in the strengthening, IPP related infrastructure and refurbishment categories. The table below indicates the planned expenditure in the various categories for the MYPD5 period. It is important to note that:

- An acceleration of the Bid Rounds for the IRP program is expected. As neither the location, capacity nor number of IPP's have as yet been announced for these future rounds, the Capex requirements are indicative at this stage to cater for these requirements. The finalization of the projects for the Bid 4 rounds are largely covered in the 2021 / 2022 submissions.
- The Cash Upfront top-up projects relate to customer projects that are not on the plan and their Cash Upfront is less than the total project costs. This is the budget for the top-up portion. Which is the difference between the total project cost and cash upfront paid by the customer.
- The DMRE have approved the Capex allocation up to 2024. The submission thereafter has been escalated on the basis of a 5% inflationary increase per annum.

TABLE 28: CAPEX EXPENDITURE REQUIREMENTS (R'M)

Capital expenditure (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Direct Customers	1 003	931	1 099	1 282	1 235	1 384	1 539	1 601
Strengthening	962	947	1 667	1 857	2 236	2 193	2 569	2 747
Refurbishment	457	451	990	1 424	1 208	1 868	1 311	1 400
Land & Rights	9	15	53	39	41	59	124	134
IPP Connections	55	61	71	430	730	1 030	1 215	1 015
Asset Purchases	157	230	298	564	678	492	126	128
BESS project	-	-	4 281	3 247	4 524	2 074	1 139	-
Eskom funded	**2 643**	**2 635**	**8 459**	**8 843**	**10 652**	**9 100**	**8 023**	**7 025**
DMRE Funded	2 432	2 691	2 339	3 013	3 165	3 323	3 489	3 663
Total capex	**5 075**	**5 326**	**10 798**	**11 856**	**13 817**	**12 423**	**11 512**	**10 688**

8.1 Distribution networks investment drivers

The following factors are the key drivers for the CAPEX expenditure:

- Enabling capacity as a precursor for growth in the economy and support to government led initiatives, including the IRP 2019 plan, up until 2025.
- Further progressing towards meeting regulatory and statutory requirements as stipulated by NERSA

- Ensuring commitment to a Distribution landscape that is focussed on the evolution of new requirements, Universal Access, Distributed Energy Resource Integration and technology advances (including disruptive technologies such as battery storage), whilst maintaining current network performance and reliability measures.
- The historical capital investment backlog is extensive and although continued investment is provided in this area, - given the deterioration in the network's aging profile and regression in the performance of the aged distribution networks, the requested investment may not fully suffice.
- Capital for strengthening and refurbishing existing Distribution networks and for new IPP and SSEG projects.
- Capital to support the evolution of the Distribution landscape to cater for a bi-directional flow of electricity, the required management of associated disruptive technologies, whilst meeting the needs of prosumers and generators, in addition to the normal load-based customer requirements.

8.2 Capital expenditure per category

8.2.1 Direct customer connections

Direct customers are end-users that are supplied by Eskom. The customers in this category exclude prepayment customers that are electrified as part of the DMRE Electrification program. These customers require investment in network infrastructure funded by the requested CAPEX. Customer projects are driven by the economic growth within the country and the projected applications made by customers. Key drivers for this category are the following:

- New customer connections in the small to medium category
- Customer willingness to pay for the required incremental load.
- Constrained networks in some parts of South Africa; constrained networks dilute the potential to connect new customers to the network that can support Eskom sales growth.
- The Licensee will continue to connect new customers to the grid within the agreed time parameters where capacity is available on the grid. The grid is continuously strengthened, based on the most recent network development plans. The ensuing needs from the Development Plans are prioritized, and projects are then executed based on the capacity and the availability of budgetary funding.

8.2.2 Network Strengthening

Network strengthening can be defined as the expansion and or upgrading of plant to increase capacity or improve the quality of supply for a defined network or area. The strengthening program expenditure is geared towards providing the shared network infrastructure for customers and generators as required by the Distribution Network Code. Correspondingly, the projects within this program provide supporting network infrastructure for electrification programmes and Government led initiatives such as the National Development Plan, the Integrated Resource Plan of 2019 and the Strategic Infrastructure Build projects. The program further ensures that network constraints are averted, as these could affect future load growth in these areas.

The funding is required in the short term due to a historically low strengthening spend. The number of constrained MV feeder networks in the Distribution business remains high, and 797 of the 8 557 MV feeders remain voltage constrained, whilst 447 networks are currently exceeding their thermal capacity. The expenditure requirements will address some of the historical issues; avert potential risk in accommodating existing customer requirements and regulatory standards. The figure below details the extent of MV networks that are currently voltage constrained (Note that the networks highlighted in red are currently voltage constrained).

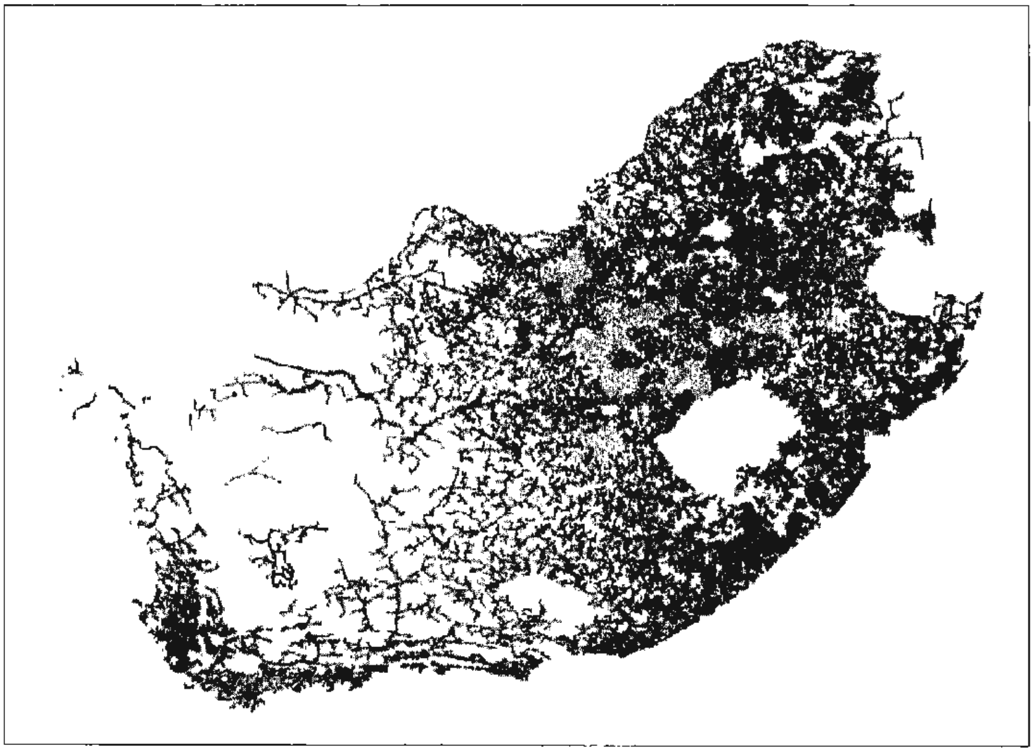
FIGURE 13: VOLTAGE CONSTRAINED MV FEEDERS IN 2019

The reliability program, as a sub-set of the strengthening program, supports compliance to the Regulatory standards, Network Code compliance and a maintenance of current network performance levels. The program is geared towards providing acceptable performance, and improved power quality within the different levels of the network infrastructure. Further improvement interventions plan to enable the reliability of networks by:

- Reducing the number of faults by addressing constrained networks, and applying more robust substation and line designs
- Limiting impacts of outages by reducing the number of customers per feeder, through splitting or adding more feeders, and implementing fuses at transformers.
- Limiting the duration of outages by automating and installing substation RTU and fault path indicators.
- Continuously improving the network visibility for operational purposes

Should the strengthening and reliability projects materialize the following illustrative network outlook could materialise. The figure below illustrates the potential impact of the number of constrained feeders that could increase dramatically if the associated investment does not materialise.

FIGURE 14: ILLUSTRATIVE EXAMPLE OF POTENTIAL IMPACT OF AN INCREASE IN CONTRAINED MV FEEDERS



The impact of an increase of constrained feeders in the country will have an impact of limiting the electrification program, reduce the potential of increased revenue as limited numbers of new customers will be able to be connected to the networks. Additionally the network performance will deteriorate, safety related incidents increase, whilst impacting the cost of unserved energy to the country.

The Licensee will include the following technology advancements into its strengthening program to enhance the reliability of its networks:

- The introduction of Distribution Automation platforms for selected networks to improve the monitoring, maintenance and operability of the Power System, taking into account the bi-directional flow of energy emanating from Distributed Generators.
- The introduction of Non-Wire alternative solutions, such as Battery Energy Storage and other hybrid solutions, to assist with the evolution of network and customer requirements.
- The introduction of a Meter Data Management System (MDMS) as part of the integration of the Smart Metering capability for the business. Eskom is experiencing an increase in overdue debt across all market sectors, non-technical energy losses (illegal connections) and an imbalance of supply and demand (overloading of the system). This system will enable the business in addressing non-payment, meter tampering, load management, online monitoring of customer usage patterns and online purchasing of electricity. It anticipates that the projected expenditure will ensure business agility and readiness in tackling illegal theft, and sustaining the financial position through effective revenue collection.
- The installation of cameras, drones and monitoring capability due to a high level of theft of equipment and an increase in number incidents impacting the safety of staff. This investment will improve the safety and security of personnel and secure equipment at remote locations.

8.2.3 Refurbishment

The primary objective of refurbishment is to extend the life of assets and the maintenance of expected performance levels. Failure to refurbish assets timeously will have a negative impact on the maintenance and operations of the network and associated equipment, with respect to increased maintenance, increased fault activity, increased maintenance resource requirements (labour, materials, fleet, budgets etc.) and deteriorating technical performance metrics. Refurbishment requirements are derived from the asset base and its associated condition. Asset obsolescence and maintainability also form an input into the refurbishment plan.

"Refurbishment is a special case of maintenance and it refers to the replacement of equipment in compliance with current technical practice, safety standards and the desired operating performance. In this case, the existing plant life is realised or even extended. Whilst maintenance focuses on supply

service enhancement, refurbishment focuses on the replacement of components of particular equipment or the entire equipment. Maintenance and refurbishment do not result into new income stream but ensures that the original stream is secured or improved." (Davidson, 2005, p.340)[1].

The refurbishment program deals with assets at the end of their life cycle that are replaced with new assets, to ensure that the networks continue to perform at accepted levels, whilst maintaining a supply to the current customer base, served by these assets. As stipulated by NERSA, a minimum level of performance is required on the Distribution Networks, which is based on the National Regulatory Standards (NRS).

A substantive amount is required for refurbishment of networks due to historical low spend within the refurbishment environments. The refurbishment plan aligns to a balanced approach between the existing performance of the networks, and the requirement to refurbish old and poorly performing networks.

For this application period, the strategies for refurbishment projects will consider the following elements:

- Condition of the network classified in terms of: Age, Maintainability/obsolescence and Safety performance of the asset
- Reducing high failure rates and safety concerns
- Normalisation of assets to new standards
- Mitigating the risks associated with any unsafe networks or equipment

8.2.4 Independent power producers (IPPs) and small scale embedded generators (SSEG)

The capital expenditure associated with Independent power producers (IPP's), is informed by the Integrated Resource Plan 2019 (published by DMRE in October 2019). It calls for an increase in generation capacity using a mix of resources, including Renewables. The actual implementation of the IRP is through ongoing Ministerial Determinations, as determined by the REIPPP process and by provisions made for Emergency Procurement programs, such

[1] Utility asset management in the electrical power distribution sector; Innocent E. Davidson.; 2005 IEEE Power Engineering Society Inaugural Conference and Exposition in Africa

as the RMIPPPP. The table below indicates the expectations emanating from the IRP 2019 program.

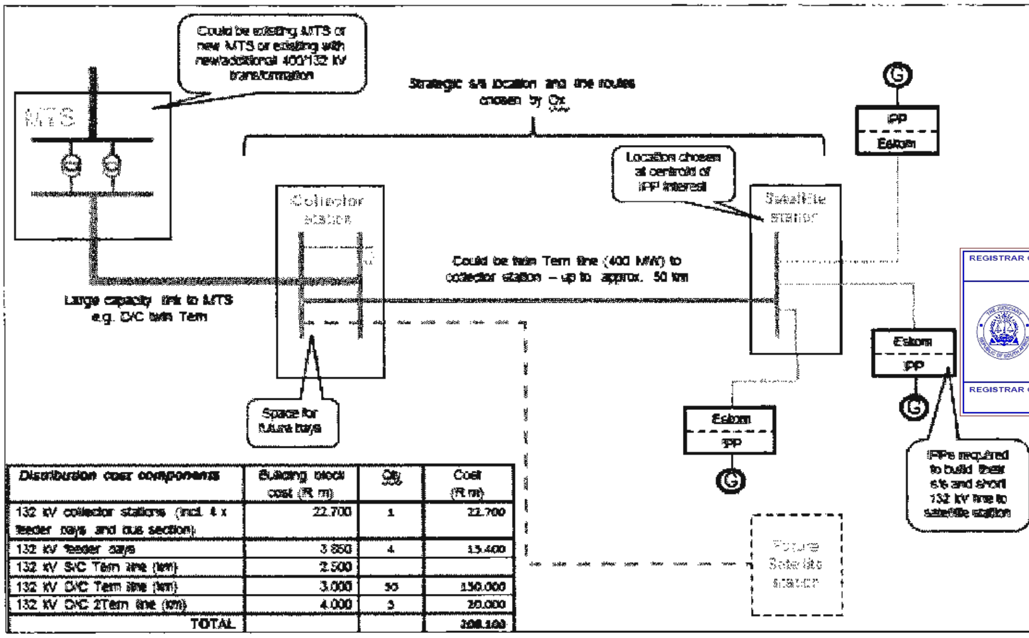
TABLE 29: IRP 2019 PROGRAM REQUIREMENTS PER SOURCE CATEGORY (PG.44)

	Coal	Coal (Decommissioning)	Nuclear	Hydro	Storage	PV	Wind	CSP	Gas & Diesel	Other (Distributed Generation, CoGen, Biomass, Landfill)
Current Base	37 149		1 860	2 100	2 912	1 474	1 980	300	3 830	499
2019	2 155						244	300		Allocation to the extent of the short term capacity and energy gap.
2020	1 433					114	300			
2021	1 433					300	818			
2022	711				513	400 / 1000	1600			
2023	750					1000	1600			500
2024			1860				1600		1000	500
2025						1000	1600			500
2026							1600			500
2027	750						1 600		2000	500
2028						1000	1 600			500
2029					1575	1000	1 600			500
2030				2 500		1 000	1 600			500
TOTAL INSTALLED CAPACITY by 2030 (MW)	33364		1860	4600	5000	8288	17742	600	6380	
% Total Installed Capacity (% of MW)	43		2.36	5.84	6.35	10.52	22.53	0.76	8.1	
% Annual Energy Contribution (% of MWh)	58.8		4.5	8.4	1.2*	6.3	17.8	0.6	1.3	

Installed Capacity
Committed / Already Contracted Capacity
Capacity Decommissioned
New Additional Capacity
Extension of Koeberg Plant Design Life
Includes Distributed Generation Capacity for own use

The Eskom Capital allocation for IPP's, provides for the shared network infrastructure that is to be created to allow for the evacuation of power from the IPPs on the DMRE program. To cater for the expectations of the IRP 2019 program, a series of Collector Stations will have to be constructed in anticipation of the IPP connections to the Distribution networks, and for the evacuation of the power into the grid. The figure below portrays a typical layout of the Collector Station.

FIGURE 15: COLLECTOR STATION REQUIREMENTS FOR THE EVACUATION OF IPP GENERATED POWER WITHIN AN MTS AREA



Distribution cost components	Building block cost (R m)	Qty	Cost (R m)
132 kV collector stations (incl. 4 x feeder bays and bus section)	22.700	1	22.700
132 kV feeder bays	3.850	4	15.400
132 kV S/C Tern line (km)	2.500		
132 kV D/C Tern line (km)	3.000	50	150.000
132 kV D/C 2Tern line (km)	4.000	5	20.000
TOTAL			208.100

The IPP is responsible for its own network establishment cost up to the point of connection. The required funding is for the related upstream strengthening projects, which are borne by the Distributor in line with the Grid Code requirements. The initial establishment cost will also have to be funded by the Distributor, to enable the aggregation of connections at the Collector Stations. The apportioned cost up to the point of connection will be for the account of the IPP, however shared network infrastructure investments will be borne by the Distributor.

8.2.5 Battery Energy Storage System (BESS)

The following elements were considered when the final list of sites were consolidated in line the project objectives for the Battery Storage Project:

- Proximity of the site to renewable energy sources (World Bank emphasis)
- Resolution of network constraint capability by using BESS
- Charging capacity available on the network in question for the BESS
- Suitable land availability to ensure project is able to be completed within timelines as agreed with the World Bank
- Planning proposals were primarily shaped by the philosophy that the Primary Use Case for the BESS installation was for Peak Shaving support (energy support service) for the System Operator during System Peak periods and for the provision of ancillary services when the system would require frequency and voltage support.

The project is to be completed in two phases, and the first phase of the project is envisaged for completion early in 2022. The balance will be commissioned in the ensuing years. Phase one of the project consists of 6 sites, and a combined 197.5 MW of BESS, with a capacity of 827 MWh is to be connected. The second phase consists of five sites, and 145.5 MW of BESS, with a capacity of 622 MWh will be connected. In addition, 60 MW of Solar PV is to be connected as part of the project. The total Capital requirements will be determined when the Design proposals are finalised and a clearer indication of BESS efficiencies, impact of ambient temperature, charging capabilities, technology types and capacity requirements, are made available.

The premise for the current Planning Proposal aligns with the overall BESS project capex requirement of R15,3bn for the project (Phases 1 and 2 respectively), dependent on the technology used for the projects.

Whilst the overall cost is yet to be determined, the justification of the projects are based on the fact that the BESS units will provide ancillary and energy support services to the system, and provide local load shaving opportunities for constrained networks, whilst providing an investment deferral option to the respective Operating Units at the same time.

In addition, the installation of BESS will provide ancillary support in terms of enhanced frequency control of the network, reactive power support and improved quality of supply performance in close proximity to existing Distributed Generation Renewable Energy plants

8.2.6 Asset purchases

The expenditure required for asset purchases includes the acquisition and replacement of workshop, production and office equipment of a capital nature. This expenditure is required to expand, operate and maintenance new and existing distribution networks. These assets include amongst others test equipment, toolboxes, live-line equipment, ladders and specialized tools for line construction.

Live-line equipment is used for maintenance of networks, while ensuring an uninterrupted supply to customers. In order to minimize customer interruptions the prior acquisition of mobile substations, strategic transformers and critical spares are required. These strategic assets are essential whilst work is carried out on the network for maintenance or in the case of failures of sub-station equipment e.g. transformers. These mobile substations and critical spares are placed in strategic location across the country for quick supply restoration essential to sustain uninterrupted supply to customers.

The extensive vehicle fleet used by the Distribution Business to operate and maintain its assets, and to service the customer requirements, has to be maintained at an acceptable level. Allowance is thus made for the replacement of vehicles that have served their useful life, and where the vehicles are no longer in a roadworthy condition to meet these requirements.

8.2.7 Electrification

Eskom continues to increase electrification connections in support of Government's objective of universal access to electricity. Funding is provided by the DMRE to meet these stated objectives for the remaining customers to be electrified. It is intended that universal access is achieved by 2025 and Eskom is currently electrifying approximately 200 000 customers per annum in line with the gazetted program, and in association with the Municipal Electrification objectives around the country.

8.2.8 Operating technology (OT) requirements

The Licensee operating systems support the daily operations and management of the Distributors Plant and Equipment. Obsolescence and limited support for outdated technology require upgrades or new systems. This intends to facilitate a changing business landscape as it increasingly gravitates towards a smart and interconnected grid.

The following operating technologies will require changes during the MYPD5 control period:

- The replacement of the distribution management system (DMS) and Supervisory Control and Data Acquisition (SCADA) with an advanced DMS due to obsolescence. This system of software and hardware allows the Licensee to control processes, operate, and to monitor and gather real time information of the electricity network for normal operations, outage scheduling and in cases of faults and emergencies. It will also allow for the integration of Energy Management systems, as required for the integration and management of technology disruptors, such as Battery Energy Storage integration requirements.
- The SmallWorld repository upgrade to the SmallWorld Enterprise Office (SWEO) system will ensure that the repository of all equipment and its associated attributes are spatially maintained (via a geo-based location). The system includes planning functionalities, and links to all performance and maintenance requirements for reporting on various performance indicators e.g. SAIDI and SAIFI.
- The implementation of a Data Analytic tool, supported by an Enterprise Historian to acquire and store real time analysis data, as required for the transition into the Fourth Industrial Revolution.

- The implementation of the Meter Management Data System (MDMS) for the management of the smart meters in the field as part of the program to manage and collect revenue, outage management and smart grid implementation.
- Due to obsolescence of customer engagement channel systems and software, there is a need to invest in the required technology to support the realization of the channel optimization project aims. This will ensure the transition to the customer required digital services.
- The acquisition of the required Operational Technology requirements for the establishment of a Distribution System Operator and Energy Trader.

9 Integrated demand management

In terms of Section 14 of the MYPD methodology, Eskom Integrated Demand Management (IDM) is required to implement Energy Efficiency and Demand Side Management (EEDSM) programmes.

The role of IDM is to influence the electricity demand profile of its customer base for the benefit of Distribution business, the entire Eskom value chain and the country as whole.

Over the past 11 years, whilst Eskom experienced a supply shortfall, IDM focused mainly on energy usage reduction and load management. It is anticipated that the country will continue experiencing a shortfall in generation capacity in the short to medium term.

In particular, EEDSM measures will also support the Distribution System Operations (DSO) by providing flexible services (dispatchable supply and demand) to maintain adequate operating reserve levels reducing evening peak demand in the industrial, commercial and residential sectors to manage grid stability and congestion on the local and national networks. Furthermore, EEDSM measures continue to be used to optimise capital expenditure on constrained networks by deferring network upgrades through localised demand-side management programmes where feasible.

Past experience has proven the valuable contribution EEDSM programmes can make to stabilising the electricity system. The demand / supply situation is cyclical and maintaining the EEDSM capacity is essential. More so, having EEDSM capacity that uses the principle of efficient energy when required by business as a means to support both excess and constrained supply situations will be a considerable asset to the industry and the economy.

9.1 EEDSM – Load management delivery channels

Eskom IDM is responsible for developing solutions and managing the delivery of energy and demand savings through a variety of programmes in the commercial, industrial, residential, and agricultural sectors

Irrespective of whether or not Eskom is in a period of excess or constrained supply, the system demand profile has a significant impact on the future supply requirements and the sources and cost of generation. The system load profile is becoming more "peaky", resulting in high production cost during peak periods and low power station utilisation during the night.

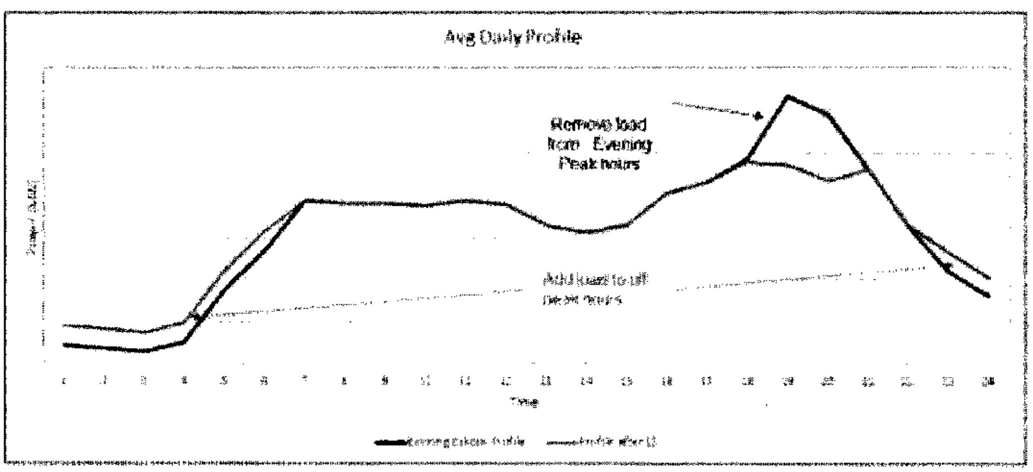
Through the Eskom Distribution Additional Capacity Programme, a number of stream initiatives have been developed. The Customer Load Management (CLM) being one of the streams was designed on EEDSM hardwired principles, to assist the grid with additional capacity. The approved sub-streams under the CLM stream are namely, Load Shifting Programme, Industrial Commercial Energy Efficiency Programme and Residential Existing Ripple Programme. The following are the key delivery channels for IDM EEDSM programmes:

9.1.1 Load Shifting Programme

The objective of the programme is to implement load shifting from evening peak periods to off peak periods, aligned to the Mega-flex TOU periods). Alleviating pressure on the power system through shifting of load by large customers has been identified as a key initiative by ESKOM in balancing the supply versus demand challenge. The benefits of implementing Load Shifting programme projects are as follows:

- Load Shifting projects change the time of day during which electricity is consumed without reducing sales volumes.
- Load Shifting projects have been seen to be rapidly implementable and cost effective compared to OCGT utilisation.
- The short-term national demand-supply situation is cyclical and maintaining capacity for future periods of supply shortage is essential.
- A flatter system load profile will reduce future generation costs and will benefit ESKOM in alleviating pressure on the power system.

FIGURE 16: LOAD SHIFTING IMPACT



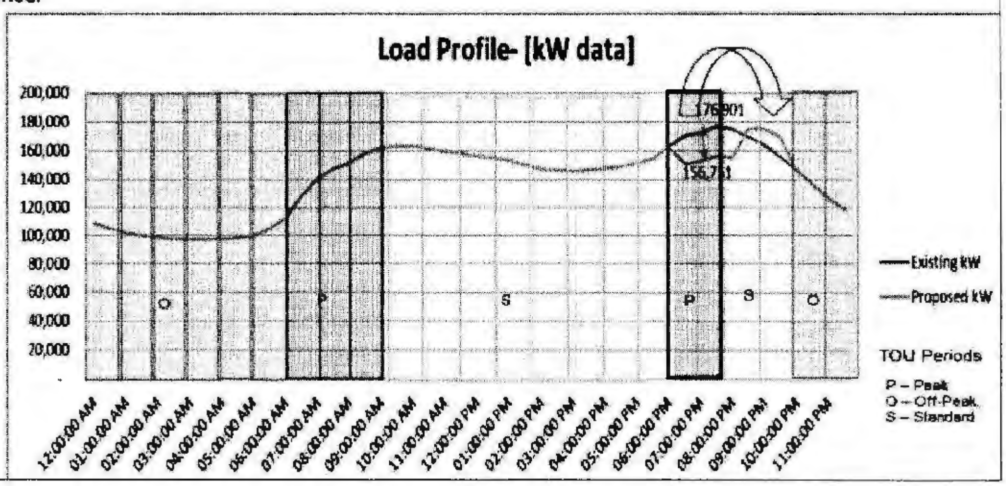
The figure above depicts management of customers load profiles such that the evening peak load is shifted to off-peak periods hence reducing OCGT utilisation in the evening peak periods.

9.1.2 Residential Existing Ripple Programme

Eskom Distribution plans to use Residential Load Management smart technologies, as part of the smart grid strategy, to shift residential peak demand to off-peak through management of residential hot water cylinders/geysers in various households within its area of supply as well as throughout South Africa in collaboration with municipalities. The smart technology will allow introduction of flexibility and central dispatchability as all the smart control systems could be aggregated for use by the Distribution System Operations as one of the levers to manage demand during constrained periods. By introducing flexibility in optimising the system load profile and supporting an optimal future generation mix, EEDSM remains a key financial and operational driver. The figure below shows a typical residential profile showing a shift of 20 MW peak demand to off peak using geyser control system

FIGURE 17: A TYPICAL RESIDENTIAL PROFILE LOAD SHIFTING (GEYSER CONTROL SYSTEM)

The aim is to control the evening demand by shifting the geyser load from Peak to Standard Time of use (TOU) period:



9.1.3 Industrial and Commercial Energy Efficiency Programme

The energy efficiency programme entails hardwired solutions that will reduce the energy consumption through the implementation of energy efficient technologies (efficient lighting, VSDs, HVAC systems, Process Optimization etc.) to produce the same output requirements.

EEDSM is used in the planning, implementation, and monitoring of distribution network utility activities, designed to influence customer use of electricity in ways that will produce desired changes in the load shape, which includes load shifting, energy conservation and strategic energy efficient load growth.

The programme designs are based on performance verification over a contracted sustainability term. IDM therefore provides financial incentives incrementally for savings realised during the sustainability phase. Not only do customers benefit from the incentive, but Eskom in the short-term reduces generation cost and in the long term delays generation expansion, thus providing a win-win solution and benefits downstream within the electricity value chain

9.2 Targeted communications programme

Eskom has initiated three campaigns to assist in stabilizing the system and reducing load. Eskom Distribution will introduce additional campaigns to support Energy Efficiency and load management technologies to the different market segments.

This programme is part of the 'Eskom Distribution Additional Capacity Programme', which assists the System Operator when the grid is tight, by reducing the demand for electricity. It involves behavioral measures in order to influence the demand. The savings are measured during the Eskom defined standard and peak periods in accordance with the approach to operating costs; a symmetrical treatment of variances is included.

The campaigns are to provide marketing/communications support to demand management solutions technologies by putting in place Load Management Marketing Mix Elements to encourage consumers to reduce demand, keeping in mind the load management key principles. The campaigns must consider the following "BIG IDEA" and rational in formulating Marketing campaigns i.e. Be Greener, Planet Issue, (Find enduring term that looks at the cyclical behavior of energy demand). The campaign must run for several years until such time that Load Management is no longer required i.e. system is stabilized and consumers are repeat buyers of technologies promoted.

The following targeted communications solutions are included:

- **Residential** – "Use electricity smartly" campaign: Create a national mass media campaign to rally the country to assist to limit or avoid load shedding, with specific focus areas:
  - 9am – 5pm period (beat the peak) – Residential mass media broadcasting campaign focusing on higher LSMs (LSM 8 -10).
  - Channels: Multi-channels (radio, digital and social media) radio focusing on evening drive-time (4pm – 6:30pm) demand reduction by switching-off and implementing saving tips, especially during constrained periods, while social media will share the campaign messaging during the day.

The estimated voluntarily demand reduction size is 15 MW / annum over the MYPD5 period. Proposed social media positioning: (#PleaseUseOnlyWhatYouNeed)

- **Business – "Use electricity smartly" campaign:** Create a national mass media campaign to rally the country to assist to limit or avoid load shedding, with specific focus areas:
  - Business hours (7am – 3pm) period
  - Channels: Business mass media broadcasting campaign (radio, digital and social media) focusing on morning drive time and through the day to manage the heating and cooling load (heating ventilation and air-conditioning HVAC load) in all sectors, during constrained periods.
  - Position Energy Advisors as energy experts who assist businesses with load optimization and energy efficient advice.

The estimated voluntarily demand reduction size is 35 MW per annum over the MYPD5 period.

- **Load management technologies support campaigns:** Put in place specific awareness campaigns for the industrial / agricultural / commercial markets. Campaigns focused at improving energy efficiency and load management in the Industrial, Agricultural & Commercial markets.
  - Channels used to educate specific segments of the market include: Appropriate print media, Appropriate Events/shows, Social media, SMS and Internet

9.3 Measurement and verification

Measurement and verification is the independent third party measurement, verification and tracking of demand and energy savings realised by the implementation of EEDSM projects by project developers. Eskom contracted a number of measurement and verification teams to independently measure, verify and report the verified savings. This improves the credibility and acceptability of the reporting to the various stakeholders. As and when needed, additional independent teams may be contracted.

Planning and budgeting for the measurement and verification function is largely dependent on the work volume received from EEDSM programme. These activities and expenses on EEDSM projects or programmes are recovered from the IDM budget, and are therefore included in this plan.

9.4 IDM key focus areas and approach

A number of key focus areas that drive integrity and quality of the various programmes underpins IDM.

Key Focus Areas	IDM Approach
Robust project management approach	IDM has built up an extensive project and contract management capacity. Where, due to variations in workload, additional capacity may be required, external resources will be contracted. For large projects, multi-functional project teams will be created, following robust project management methodologies.
Project governance and approval	Eskom governance processes will be complied with.
Ensuring that estimated savings do realise as anticipated	Measurement and Verification (M&V) is responsible for independent third party measurement, verification and tracking of demand and energy savings.
Pro-actively address potential fraud	All IDM programmes are subject to the Eskom audit requirements.
Safety	Eskom will specify compliance to safety, health and environmental requirements and standards.

9.5 Technical and cost calculations

9.5.1 Energy and Demand savings

The estimated demand savings in the IDM plan are based on a combination of a projection of estimated savings of the various individual projects and large-scale initiatives, and the technical potential of savings that can be achieved per sector.

Maximum demand is measured at the maximum point of the load profile and is generally measured in Megawatts (MW). It is also the maximum electricity consumed at a given point in time. EEDSM programmes targets and reports peak demand and energy savings. This is based on the average demand measured during Eskom evening peak periods (6pm to 8pm summer and 5pm to 7pm winter), refers to the full year and is measured in MW.

IDM aims to implement measurable and sustainable demand and energy-reduction interventions by introducing energy efficiency and load-reduction technologies and behaviours into customers" electricity purchasing patterns. If adequately funded, Eskom's current IDM initiatives can rapidly contribute to closing the foreseen energy gap. This is important, because the risk of load shedding and the requirements to reduce energy consumption are crucial to ensuring security of supply.

9.5.2 Cost benchmarks

The cost benchmarks are programme specific and are expressed as a maximum monetary value or expenditure cap up to which Eskom IDM will fund a project. Additional project costs falling above this benchmark are to be funded by the customer. Given the levels of the rebates, the customer business cases are generally very lucrative with short payback periods that incentivise their investments. When calculating the value of the benchmark consideration is made regarding the incentive level that would yield sufficient uptake, of the offer, by the market, the cost of implementation and consideration to cost avoidance. In addition, IDM is driven by the objectives of Supplier Development and Localisation. Cost benchmarks are also adapted to ensure sufficient uptake from these sectors. The benchmarks are used to determine the project cost and are usually specified in R'm per MW.

9.5.3 Project costs

The annual cost estimates are based on the actual historically incurred project costs from invoicing schedules and are spread equally over the duration of implementation of a project. In general, costs are calculated based on the expected peak demand savings (MW) to be delivered during a financial year, as well as associated cost to deliver the demand savings. The Load management and Residential Load Management Programmes are Performance Contracting models and will have an impact on the budgeting process, in that project funding will be payable over a three year sustainability period after implementation. It is assumed that all costs are incurred in the same year as the realised savings.

9.6 IDM MYPD5 application costs

The IDM MYPD5 application includes the EEDSM programme and the Targeted Communications programme. The total estimated cost over the MYPD5 period is R1.192bn. The IDM MYPD5 cost breakdown is provided in the table below.

TABLE 30: IDM MYPD5 APPLICATION COST

IDM Cost (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
EEDSM - Load Management Programmes	-	-	253	288	264	172	51	55
Measurement and Verification (M&V)	-	1	10	17	20	23	9	9
Marketing - EEDSM Programme Support	26	65	5	6	7	9	4	4
Targeted Comunications Programme	0	0	116	122	129	134	-	-
Total IDM	**26**	**66**	**384**	**433**	**420**	**339**	**64**	**68**

The Targeted Communications Programme cost is R385m over the MYPD5 period. The cost breakdown over the MYPD5 period is provided in the table below.

9wA

TABLE 31: TARGET COMMUNICATIONS PROGRAMME COST

Targeted Communications Programme Cost (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
Residential: Use Electricity Smartly	-	-	32	34	36	37	-	-
Business: Use Electricity Smartly	-	-	74	77	82	84	-	-
Load Management Support	-	-	10	11	12	13	-	-
Total	-	-	**116**	**122**	**129**	**134**	-	-

The EEDSM programme cost is R724m at a benchmark cost of R2.5m/MW to achieve 290 MW peak demand savings over the MYPD5 period. The tables below provide EEDSM Programme demand savings and cost breakdown respectively.

TABLE 32: EESDSM PROGRAMME – DEMAND SAVINGS (MW)

EEDSM Programme Demand Savings (MW)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
EEDSM - Load Management Programmes	-	-	101	115	106	69	25	27

TABLE 33: EEDSM PROGRAMME COSTS

EEDSM Programme Cost (R'm)	Actual FY2020	Projection FY2021	Projection FY2022	Application FY2023	Application FY2024	Application FY2025	Post Application FY2026	Post Application FY2027
EEDSM - Load Management Programmes	-	-	253	288	264	172	51	55

10 Revenue Recovery

Eskom allowable revenues are recovered through the Distribution Licensee by way of Standard tariffs and non-standard tariffs, that is, Negotiated Pricing Agreements (NPAs) and international utility tariffs. This is after the pass-through of the MYPD allowable revenues to the Distribution Licensee, see table below.

In this MYPD5 application, the existing NPAs (local and international) and international utilities revenues are escalated as per their respective contracts that were implemented with NERSA prevue. Consequently, the increase to the Standard tariffs is to recover the balance of the NERSA allowed revenues after subtracting the revenues from NPAs and international utilities.

TABLE 34: MYPD5 REVENUE RECOVERY

Revenue recovery R'm	Application FY2023	Application FY2024	Application FY2025
Non standard tariff customers	17 167	16 979	17 897
Standard tariff (including RCA's)	276 263	317 696	347 299
Total Allowable Revenue	**293 430**	**334 676**	**365 195**

10.1 Revenue recovery through tariff increases

The NERSA allowable revenue decisions will be implemented prior to the commencement of each Eskom financial year of the MYPD5 control period. The implementation will be through the applicable NERSA methodology and decisions including the NERSA RCA decision(s) and court outcomes, NERSA ERTSA decisions and other tariff and pricing decisions (such as updates to tariff structures. The annual tariff adjustment implementation will be effective 1 April for non-municipal customers and from 1 July for municipal customers in compliance to the Municipal Finance Management Act (MFMA).

The annual MYPD allowable revenue decision is aligned to the Eskom financial year, that is, 12 months from 1 April to 31 March of the following year. The Municipal Finance Management Act (MFMA) requires that electricity price increases to municipalities are only effective on 1 July, subject to Eskom (as the electricity supplier) tabling the adjusted rates in Parliament on or before 15 March in the implementation year. The Eskom directly supplied customers' (non-municipal) tariffs are therefore, effective 1 April and the municipal tariff increase is on 1 July.

NERSA's ERTSA methodology governs the calculation of the tariff increases to be applied to the different tariff charges, and this includes a separation of municipal and non-municipal tariffs to ensure that:

- Over the 12 months of the Eskom financial year, the municipal and non-municipal tariffs annual average increases are the same.

Because for the first 3 months of the Eskom financial year, the prior year's municipal tariffs are effective, the municipal price increase for the last 9 months ensures that for the 12 months of the Eskom financial year, the average municipal increase results in the same average increase with non-municipal tariffs as above.. Consequently, the 1 July Eskom municipal tariff increase applied to the tariff charges may be different from the non-municipal increase, that is, could be higher or lower depending on the prior year's 1 July municipal increase.

The tariff increases applied to the NPAs and the international utility agreements are specified in their supply agreement contracts. In the MYPD5 application, the NPA and international utilities revenues are escalated to reflect these contracts contribution to the requested Eskom allowable revenues for the respective years of the MYPD5 control period.

10.2 Pass-through of allowable revenues to the Distribution Licensee

The MYPD methodology facilitates the recognition of the Generation (Gx) and Transmission (Tx) costs in the Distribution Licensee through the pass-through rule. This enables the recovery of the Eskom allowable revenues from Standard tariffs and non-standard tariffs (NPAs and international utilities' tariffs).

The total Generation allowable revenues including the costs from Transmission for use of Tx networks, ancillary and Tx losses are passed-through to the Distribution Licensee.

The Transmission allowable revenues less those included in the Generation pass-through are passed through to Distribution. This sharing in the Transmission allowable revenues is in compliance with the Grid Code that requires Transmission to allocate its allowable revenues to generators (Generation Licensee) and to loads (Distribution Licensee).

In order to separate the Standard tariff allowable revenues from non-standard tariff customers (NPAs and international utility tariffs) the sales revenues for international sales and local NPAs are subtracted from total allowable revenues passed through to the Distribution Licensee, see table below.

TABLE 35: PASS-THROUGH TO DISTRIBUTION

Allowable Revenue (R'm)	Application FY2023	Application FY2024	Application FY2025
Generation (Gx)	246 339	281 322	309 476
Transmission (Tx)	9 779	13 234	13 880
Distribution (Dx)	37 312	40 119	41 839
Eskom total	**293 430**	**334 676**	**365 195**
	Pass-through to Distribution Licensee (R'm)		
	FY2023	FY2024	FY2025
Eskom Total	**293 430**	**334 676**	**365 195**
Generation (including costs from Tx)	247 222	283 247	311 291
Transmission	8 897	11 310	12 065
Distribution Licensee allowable revenues	37 312	40 119	41 839
Dx Licensee after pass-through	**293 430**	**334 676**	**365 195**
Non-standard tariff customers	17 167	16 979	17 897
Standard tariffs	276 263	317 696	347 299

10.3 Indicative annual standard tariff increases at an Eskom total level

The indicative annual standard tariff increases based on the requested MYPD5 allowable revenues and this application's forecasted sales are as shown in the table below.

TABLE 36: INDICATIVE ANNUAL STANDARD TARIFF INCREASES AT AN ESKOM LEVEL

Standard tariff price impact (R'm)	Unit	Decision FY2022	Application FY2023	Application FY2024	Application FY2025
Standard tariff revenues	R'm	245 710	276 263	317 696	347 299
Standard tariff sales volumes	GWh	183 856	171 549	171 440	170 370
Standard tariff average price	c/kWh	133.64	161.04	185.31	203.85
Standard tariff annual average increase	**%**	**15.06%**	**20.50%**	**15.07%**	**10.00%**

In accordance with the NERSA MYPD methodology, NERSA may revise this application's forecasted sales volumes to reflect the prevailing situation prior to an MYPD5 decision. In this regard, the tariff increases would be adjusted accordingly as they are subject to the NERSA decision forecasted sales and allowed revenues for each year of the MYPD5 control period.

10.4 Determination of standard tariff category increases

The annual tariff increase is implemented to recover the MYPD decision allowed revenues. Annual standard tariff increases are by tariff category that is municipal and non-municipal. The increase Affordability subsidy charge reflects the change in this subsidy charge value.

The NERSA ERTSA methodology is applied to determine tariff category increases as follows:

- The annual average standard tariff increase (based on the Eskom financial year), as per Rule 5 of the ERTSA methodology is used further to determine the individual municipal and non-municipal annual revenues to equal annual average tariff increases.
- The 1 July municipal (Local authority) tariff increase is calculated as per Rule 6 of the ERTSA methodology that requires the recovery of the change in the 12-month municipal revenues through a 1 July tariff increase.
- The non-municipal (Non-local authority) average increase is the annual average Standard tariff increase as per rule 5.8 of the ERTSA methodology.
- The Affordability subsidy charge increase follows on Rule 7.1 and Rule 7.2 of the ERTSA methodology that provides for the Energy Regulator as part an MYPD decision to allow cross-subsidies for implementation as a part of the annual average Standard tariff increase.
- The Affordability subsidy charge caters for the recovery of the historic lower increases to the Homelight 20A tariff and it therefore recovers the cumulative difference of lower tariff increases to the Homelight 20A tariff since 2013/14.

The ERTSA standard tariff category increases do not result in structural changes and implementation of new tariffs as per the current (at the time of this MYPD5 application) ERTSA methodology rule 3.2.

During the MYPD5 Eskom will make applications for tariff structural changes after the allowable revenue decision. Upon the NERSA approval of the updated tariff structures, Eskom will adjust the updated tariff rates using the ERTSA methodology to reflect the implementation year's price levels.

10.5 Indicative MYPD5 standard tariff increases

The indicative increases to the standard tariffs in this MYPD5 application only include the consideration of this application's applied for allowable revenues and forecasted sales.

The indicative 2022/23, 2023/24 and 2024/25 tariff increases by standard tariff categories are set out in the table below.

The 28 February 2013 MYPD3 decision provides that the affordability subsidy charge is recovered from key industrial and urban non-municipal customers (that is, not from municipal tariffs). Consequently, the large industrial and urban (non-municipal tariffs paying the affordability subsidy) will on average experience a -0.18% to the 1 April 2022 20.50% increase due to 15.66% increase to the affordability subsidy; an additional 0.02% from 1 April 2023 and an additional 0.18% from 1 April 2024.

TABLE 37: STANDARD TARIFF CATEGORY INCREASES

Standard tariffs and categories	Application FY2023	Application FY2024	Application FY2025
Standard tariff annual increase	20.50%	15.07%	10.00%
Municipalities			
Municipal tariffs - effective 1 July	21.00%	13.30%	8.90%
Eskom direct customers (non-municipal tariffs)			
Businessrate, Public lighting, Homepower, Homelight 60A, Homelight 20A, Landrate and Landlight	20.50%	15.07%	10.00%
Megaflex, Miniflex, Nightsave Urban, WEPS, Transflex, Megaflex Gen			
• Affordability susbidy charge (where applicable)	15.66%	15.45%	14.74%
• Other tariff charges	20.50%	15.07%	10.00%
*Effective increase including affordability subsidy	20.32%	15.09%	10.18%
Ruraflex, Nightsave rural, Ruraflex Gen	20.50%	15.07%	10.00%
Homelight 20A			
• IBT Block 1: >0 to 350kWh	20.50%	15.07%	10.00%
• IBT Block 2: >350kWh	20.50%	15.07%	10.00%

Note: The above is based on the current tariff structures. Following a tariff structure, the increases may differ e.g. if the structure of the affordability charges change then the increase will also change.

10.6 Environmental levy and Carbon tax (Levy) recovery

A c/kWh rate is used to recover the costs of the applied for recovery of the environmental levy and carbon tax costs from all customers. For standard tariffs, the recovery of the levies' costs is embedded in the energy tariff rates. For the local NPA and international sales an explicit levy c/kWh charge is raised.

11 Conclusion

The Licensee application supports the Eskom mission to provide sustainable electricity solutions to promote economic growth and social prosperity for South Africans. This is achieved through operating the distribution network to supply electricity to customers in its area of supply as specified within the Distribution licence.

Eskom's sales have declined over the past years, with the outlook remaining relatively depressed in the years ahead. A significant decline is attributed to large power users as a result of high ore extraction costs and volatile commodity markets, particularly in the ferrochrome, steel, gold and platinum industries. The measures that Eskom has undertaken to arrest this trend have been provided. It needs to be noted that the sales are a feature of the economy of the country and requires a concerted effort from various stakeholders.

Distribution's operating expenditure that includes employee costs, maintenance and other expenses has experienced a compound average growth rate (CAGR) for the period of 3.8%, which is below expected inflation. This has been a result of efficiency improvements since the MYPD4 period. Prioritising capital investments to build assets that support network performance in order to deliver reliable network performance. Due to the phasing-in of the return on assets, the consumer continues to enjoy a subsidy.

While good payment from large industrial, commercial and major metropolitan customers has been received, the areas of major concern are certain residential and municipal debt. Municipal overdue debt has increased significantly in the past few years and remains a concern. Interventions including with Government Departments and task teams are assisting in providing innovative solutions to address the fundamentals of challenges being faced.

From: Naude Pienaar <naudepienaar@vodamail.co.za>
Sent: 20 June 2022 16:42
To: 'Ntidiseng Makgamatha'
Cc: dutoitboeta@mweb.co.za
Subject: FW: [CAUTION:EXTERNAL EMAIL] - LOAD REDUCTION AGRI NW / ESKOM MEETING: 25 APRIL 2022

Good morning Madam,

The meeting we had regarding load reduction refers.

As you know, we have already requested a follow-up meeting. Could you please provide us a few possible dates.

I have also enquired feedback about:
a) Our request to suspend load reduction until the results of the audits are available,
b) The results of the audit process that allegedly took place,
c) The names of the other 62 lines where load reduction is also taking place as you announced in our previous meeting.

We hope to hear from you soon.

Naude Pienaar
Pp Agri NW

From: Ntidiseng Makgamatha [mailto:MakgamND@eskom.co.za]
Sent: Friday, May 6, 2022 12:09 PM
To: Marlize Fritz; 'Naude Pienaar'; dutoitboeta@mweb.co.za
Cc: Meladi Botabota
Subject: RE: [CAUTION:EXTERNAL EMAIL] - LOAD REDUCTION AGRI NW / ESKOM MEETING: 25 APRIL 2022

Good day,

Good day,

Your proposal was presented to the Operating Unit leadership and unfortunately Eskom is unable to suspend the load reduction.
The principles applied for load reduction are that we complete the interventions, which is to audit the feeder, monitor that losses are reduced to acceptable level and then load reduction can be uplifted.

We also confirm that the team is on site until next week to do audits in the Skuinsdrift and Mimosa

Regards
Ntidiseng Makgamatha
Middle Manager Customer Relations
Customer Services-NWOU
GEMMA Cluster

From: Ntidiseng Makgamatha
Sent: Tuesday, 26 April 2022 13:57
To: Marlize Fritz <marlize@agrinw.co.za>
Cc: 'Naude Pienaar' <naudepienaar@vodamail.co.za>; dutoitboeta@mweb.co.za
Subject: RE: [CAUTION:EXTERNAL EMAIL] - LOAD REDUCTION AGRI NW / ESKOM MEETING: 25 APRIL 2022

Good day

I acknowledge receipt of the mail and have forwarded the proposal to OperatingUnit leadership

Will revert back to you before end of next week

Regards
Ntidiseng Makgamatha
Middle Manager Customer Relations
Customer Services NWOU
GEMMA Cluster
082 937 6302

From: Marlize Fritz <marlize@agrinw.co.za>
Sent: Tuesday, 26 April 2022 07:53
To: Ntidiseng Makgamatha <MakgamND@eskom.co.za>
Cc: 'Naude Pienaar' <naudepienaar@vodamail.co.za>; dutoitboeta@mweb.co.za
Subject: [CAUTION:EXTERNAL EMAIL] - LOAD REDUCTION AGRI NW / ESKOM MEETING: 25 APRIL 2022
Importance: High

Attention: Me. Ntidiseng Makgamatha

LOAD REDUCTION

With this we would like to thank you for the meeting we had with your team today, to discuss the load reduction on the Mimosa and Pella feeders. For your attention and convenience take note of the attached ESKOM Agri SA / NW Protocol for Access to Farms currently in force.

Whilst understanding the challenges Eskom has with losses, lack of capacity, shortage of staff and equipment, we also appreciate your agreement and understanding that paying customers should not be in a position where they are losing a lot of income because of load reduction.

We also appreciate your proposal that the Eskom team will propose a workable solution to complete audits on the specific lines in order for Eskom to make better informed decisions. Agri NW will support such a process and will communicate this to our structures.

We would also like to request that load reduction on these two lines will be stopped immediately, pending the outcome of the audits and the subsequent arrangements with affected customers. This will alleviate the very high frustration levels of complying customers and might lessen the propability of expensive legal steps currently being considered by some customers.

Hope to hear from you soon.

Yours sincerely.

Naude Pienaar
General Manager
Agri NW

0140

Marlize Fritz
Sekretaresse

Tel: 018 632 3612/3624/2987
Posbus 3185 • Swartstraat 5 • Lichtenburg • 2740

AGRI NW

NB: This Email and its contents are subject to the Eskom Holdings SOC Ltd EMAIL LEGAL NOTICE which can be viewed at http://www.eskom.co.za/Pages/Email_Legal_Spam_Disclaimer.aspx

X6 0141

KRIEK WASSENAAR & VENTER ING
Prokureurs • Aktevervaardigers • Attorneys • Conveyancers

Our ref: PJ Wassenaar/es/QB0973
Your ref:

1 August 2022

ESKOM HOLDINGS SOC LTD
MEGAWATT PARK
MAXWELL DRIVE
SUNNINGHILL
SANDTON

URGENT

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA GAUTENG DIVISION, PRETORIA
Private Bag X67, Pretoria 0001
REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA GAUTENG DIVISION, PRETORIA

By e-mail: andrew.anderson@eskom.co.za
chose.choeu@eskom.co.za
MediaDesk@eskom.co.za
csonline@eskom.co.za

Sir / Madam

SAKELIGA NPC / ESKOM HOLDINGS SOC LTD - LOAD REDUCTION POLICY

1. We confirm that we act for Sakeliga NPC ["our client"].

2. Our client has been approached by several of its supporters, who include Agri North West, the Transvaal Agricultural Union (TLU SA), their respective members and other organisations and individuals who are direct customers of Eskom in the North West and Limpopo provinces.

3. For the purposes of this letter, our instructions are that direct customer of *inter alia* the following Eskom supply lines are affected:

3.1 North West - Mimosa feeder line;

3.2 North West - Pella feeder line;

3.3 Limpopo – ST 2021 feeder line;

3.4 Limpopo – ST 2022 feeder line;

3.5 Limpopo – Sanria Rural / Tuinplaas feeder line;

uA

www.kwv-inc.com
(t) (+27) 12 756 7566• (f) (+27) 86 596 8799 (a) 3rd Floor, HB Forum Building, 13 Stamvrug Road, Val de Grace, Pretoria 0184
(p) Postnet Suite # 11, Privaatsak / Private Bag X025, Lynwood Ridge, 0040 • BTW Reg: 4020260685

Direkteure/ Directors: Johan Kriek (B Proc, LLM), Pieter Johannes Wassenaar (LLB)
Bygestaan deur/assisted by Tertia Johanna Wassenaar (LLB), Kayla Dames (Bcom LLB), Rohann Eloff (Bcom LLB);
Konsultante / Consultants: Catherina Elizabeth Pienaar (BA, BCur, LLB, LLM, PhD), Sylvia Adriana Venter (LLB)
• Reg: 2012/030418/21
Docdate 20220308

3.6 Limpopo – SLG 2022 feeder line;

3.7 Limpopo – SGP 2021 feeder line;

3.8 Limpopo – Soutpan/Ingwe feeder lines;

3.9 Limpopo – Zebra feeder lines;

3.10 Limpopo – Levubu K feeder lines;

3.11 Limpopo – Mulendane / Tshakuma feeder line;

3.12 Limpopo – Lephalale TST feeder line;

3.13 Limpopo – Villa Nora / Rural Marken feeder line;

(the "affected direct customers")

4. The affected direct customers have been experiencing continual electricity supply disruptions [a.k.a "blackouts"] in addition to the implementation of the national program of load-shedding since November 2021.

5. The introduction of these additional outages coincided with Eskom's announcement that it would implement load reduction in six provinces, ostensibly to avoid overloading the network and resulting damage to infrastructure in "high-density areas that are prone to network overloading".

6. Section 5.7.1 Electricity Regulation Act 4 of 2006 provides that:

> *"Customer voluntary and involuntary load reduction events are characterised by the curtailment, partial curtailment, or reduction of customer load magnitude, but no actual interruption of supply occurs."*

7. Despite the locality of the affected direct customers, being mostly agricultural farms and smaller organisations, not falling within high high-density areas, the feeder lines concerned have been subjected to continual electricity supply disruptions which are attributed to 'load reduction' by Eskom and which occur in addition to the implementation of the national program of load-shedding.

uA

8. However, in respect of these affected direct customers on the affected feeder lines, Eskom is not implementing load reduction in the manner provided for in section 5.7.1 Electricity Regulation Act. Instead, the affected direct customers are simply being subjected to additional blackouts without adequate forewarning or explanation by Eskom.

9. It is our instruction that during a meeting conducted between Eskom and Agri North West on 25 April 2022, Eskom undertook to propose a workable solution to complete audits on the two specific feeder lines in order to manage the need to implement load reduction. Agri North West undertook to support the process and communicate and facilitate any necessary steps with its structures.

10. Agri North West further requested that load reduction on the two specific feeder lines, the Mimosa and Pella feeder lines, be stopped immediately, pending the outcome of the audits and the subsequent arrangements with affected direct customers in order to alleviate the impact on paying customers.

11. In a response to the aforesaid request on 6 May 2022, your Ntidiseng Makgamatha ["Makgamatha"] advised that Eskom would continue to implement load reduction on the aforesaid lines as an interim measure, pending an audit of the feeder lines and the monitoring of reduction in losses to an acceptable level.

12. Makgamatha further stated that she confirmed and effectively undertook that "the team is on site until next week to do audits in the Skuinsdrift and Mimosa".

13. However, in the intervening 2-month period, the affected direct customers have not been contacted by Eskom for the purposes of executing the audit referred to by Makgamatha, or at all.

14. Further communications from Agri North West to Eskom, enquiring as to the execution of the audit, have not received the courtesy of a response.

15. There is presently no evidence at all to suggest that the audit referred to by Makgamatha is being executed, notwithstanding the fact that the two specific feeder lines continue to be subjected to blackouts under the guise of load reduction.

16. In the circumstances, the only reasonable conclusion is that:

16.1 Eskom is imposing targeted black-outs on its direct customers under the guise of load reduction;

16.2 Eskom is thereby acting in breach of the Electricity Regulation Act 4 of 2006; and

16.3 Eskom is thereby prejudicing:

16.3.1 the ability of its direct customers to conduct their businesses, especially in the farming and related agricultural sectors;

16.3.2 electric equipment and infrastructure on the affected businesses and farms, utilised in the affected direct customers' conduct of their businesses, which is damaged or at risk of damage by unannounced blackouts;

16.3.3 the profitability of affected businesses, and in turn puts at risk thousands of employment opportunities in the affected areas;

16.3.4 the food security of the Republic of South Africa, which is reliant on the ability of its direct customers to conduct their businesses in the farming and related agricultural sectors; and

16.3.5 the safety and securing of all persons residing on or otherwise present on the affected farms during targeted black-outs on its direct customers, implemented under the guise of load reduction.

17. These prejudicial impacts have been exacerbated by the recent escalation of the national program of load-shedding, which sees Eskom implement levels 4 and 6 loadshedding on impractically short notice to customers.

18. In addition to the aforesaid, our client has been approached by other organisations, businesses and individuals across the North West and Limpopo provinces, whose members report similar electricity supply disruptions in their respective provinces.

19. Eskom's approach appears to be extensively coordinated to target South Africa's farming communities discriminately and unfairly.

20. In the present instance, we are accordingly instructed by our client to address the following demand to Eskom:

20.1 That Eskom provide our offices with an undertaking in writing within 10 days of this letter to the effect that it will conduct and complete an audit of all feeder lines stated in paragraph 3 above, within 3 months of this letter;

20.2 That Eskom provide our offices with an undertaking in writing within 10 days of this letter to the effect that, pending the execution of an audit of the affected feeder lines, Eskom will only implement load reduction as provided for in section 5.7.1 Electricity Regulation Act 4 of 2006 subject to the provision of reasonable written notice to affected direct customers;

20.3 That Eskom provide our offices with an undertaking in writing within 10 days of this letter to the effect that Eskom will immediately cease with the implementation of electricity disconnections/disruptions on the affected feeder lines, other than in the implementation of the national program of load-shedding;

20.4 That Eskom provide our client with a report on its audit of the affected feeder in order for our client to advise its supporters on the status and outcome of the line audits conducted by Eskom.

21. Our client hopes that this matter can be resolved amicably and expeditiously. However, should we not receive an adequate response to the aforesaid demand, our client reserves the right to institute appropriate legal action against Eskom without further notice to yourselves, which may include urgent applications.

22. Our client and its affiliated organisations are also willing to meet with Eskom in order to seek long term solutions.

23. We trust that you will find this in order and we await your responses.

Yours faithfully,

KRIEK WASSENAAR & VENTER ING
PÉTER WASSENAAR – DIREKTEUR / DIRECTOR
Elektronies geteken
Electronically signed
(f) 086 596 8516
(e) peter@kriekprok.co.za

Elbie Swanepoel

From:	Peter Wassenaar
Sent:	03 August 2022 16:41
To:	andrew.anderson@eskom.co.za; chose.choeu@eskom.co.za; MediaDesk@eskom.co.za; csonline@eskom.co.za
Subject:	URGENT: SAKELIGA NPC / ESKOM HOLDINGS SOC LTD - LOAD REDUCTION POLICY
Attachments:	Eskom SOC Ltd sent 20220803.pdf
Importance:	High

Good day

Please see attached letter. Kindly acknowledge receipt.

Yours faithfully / Die uwe

Pèter Wassenaar
Kriek Wassenaar & Venter Ing
Direkteur / Director
• (t) (+27) 12 803 4719 (c) 0829204474
• (a) Third Floor, HB Forum Building, 13 Stamvrug Street, Val de Grace, Pretoria
• (p) Postnet Suite # A7, Privaatsak / Private Bag X592, Silverton, 0127 • BTW Reg: 4020260685 • Reg: 2012/030418/21

KRIEK WASSENAAR & VENTE

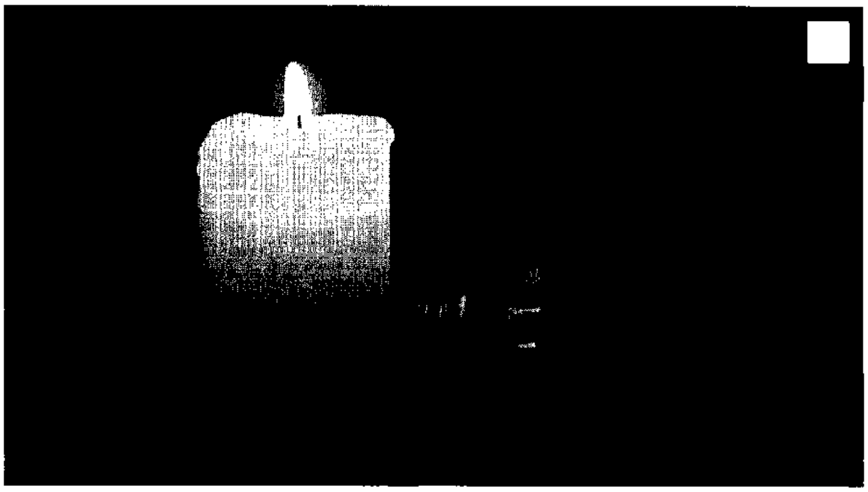
1

Ju4

MONEY AND MARKETS

Eskom's load reduction may hit your area - here's how it works

Business Insider SAPhumi Ramalepe,



(Getty)

Since mid-May, large parts of Gauteng have been hit by "load reduction".

Unlike "load shedding", this is not due to a shortage of electricity in the national grid.

Instead, Eskom is trying to protect its transformers from a surge in illegal electricity usage.

For more stories go to www.BusinessInsider.co.za.

Large parts of Gauteng have been hit with "load reduction" in recent weeks. But Eskom is adamant that South Africa may only suffer three days of "load shedding" this winter.

CURRENCIES COMMOD

Rand - Dollar	18
Rand - Pound	20
Rand - Euro	17.
Rand - Aus dollar	11.
Rand - Yen	0.1

All JSE data delayed by at least 1

Most Read
0148

What's the difference?

Load shedding is when South Africa does not have enough capacity to generate electricity, and the country is hit by scheduled, controlled blackouts across different areas.

Introduced in mid-May this year, load reduction is when power is switched off in neighbourhoods where illegal connections cause overload and damage infrastructure.

According to the Eskom, load reduction is meant to protect its infrastructure by reducing electricity usage during peak hours.

Eskom spokesperson Sikonathi Mantshantsha says the increase of illegal connections in high density areas in the province and the growing number of backyard dwellings connecting to a single house are overloading neighbourhood electricity systems.

"Once the transformer is overloaded, it then explodes and that whole area will not have electricity," said Mantshantsha.

When a transformer explodes, it cannot be fixed but can only be replaced and on average, it costs between R50,000 to R100,000 to replace it.

In the past year, Gauteng alone has lost more than R1 billion to replace damaged infrastructure caused by illegal connections.

In recent months, it has stopped replacing transformers damaged by these connections.

"[We] will not be fixing that infrastructure until we have resolved the problem that's illegal connections, until the people agree to pay for the electricity in those areas."

Recommended

CURRENCIES COMMOD

Rand - Dollar	18
Rand - Pound	20
Rand - Euro	17.
Rand - Aus dollar	11.
Rand - Yen	0.1

All JSE data delayed by at least 1

Follow:
Facebook

22/12/2022-11:31:00 AM

It is also now switching off power when it sees signs of illegal power use.

"Eskom has decided that whenever we notice a surge in demand in that area beyond what the network is designed for, to switch off in order to protect infrastructure, so we call that load reduction," said Mantshantsha.

So far, these areas in Gauteng have been hardest hit: Cosmo City, Diepsloot, Ivory Park, Orange Farm, Sebokeng, Soweto, Vaal, Katlehong and Kagiso.

In order to ease the burden on infrastructure, Eskom has decided to implement load reduction daily when the most damage occurs, from 5:00 to 9:00 and later between 17:00 and 22:00.

Residents are advised to switch off their electrical appliances to avoid a surge when electricity returns, and not to log any faults during this period.

Receive a daily update on your cellphone with all our latest news: click here.

Get the best of our site emailed to you daily: click here.

Also from Business Insider South Africa:

- **This year, SARS may 'auto-assess' your tax return – here's what you need to know**
- **The Level 3 rules have just changed - what you need to know**
- **You'll be able to go to a restaurant or casino from today – but you can't have booze there**
- **ANALYSIS | NDZ just triumphed over tobacco – and became all but legally untouchable**
- **Holidays still banned: South Africans only allowed to take day trips**

Read more on:

ESKOM | SIKONATHI MANTSHANTSHA | TOWNSHIPS | SHACKS | LOAD REDUCTION

Most Read

0149

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA
Private Bag X67, Pretoria 0001

Recommended

Two passenger jets collided on a runway at Heathrow airport

96-year-old Queen Elizabeth's death certificate says she died of 'old age'

MEDIA24 PRIVACY POLICY

CURRENCIES COMMOD

VULNERABILITY DISCLOSURE

Follow:

Rand - Dollar	18
Rand - Pound	20
Rand - Euro	17.
Rand - Aus dollar	11.
Rand - Yen	0.1

All JSE data delayed by at least 1

Two passenger jets collided on a runway at Heathrow airport
Business Insider

96-year-old Queen Elizabeth's death certificate says she died of 'old age'
Business Insider

A designer who helped roll out FNB's first logo still thinks the 'AK-47' was deliberate
Business Insider

An unopened iPhone from 2007 just sold for R700,000
Business Insider

Most Read
0150

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA
Private Bag X67, Pretoria 0001
REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA

Recommended

Two passenger jets collided on a runway at Heathrow airport

96-year-old Queen Elizabeth's death certificate says she died of 'old age'

MEDIA24 PRIVACY POLICY
CURRENCIES COMMOD
VULNERABILITY DISCLOSURE

Follow:
Facebook

Rand - Dollar	18
Rand - Pound	20
Rand - Euro	17.
Rand - Aus dollar	11.
Rand - Yen	0.1

All JSE data delayed by at least 1

22/12/2022-11:31:00 AM

DAILY EMAIL NEW

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA
Private Bag X67, Pretoria 0001

Sign u

Recommended

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA

Two passenger jets collided on a runway at Heathrow airport

96-year-old Queen Elizabeth's death certificate says she died of 'old age'

ABOUT US

VIEW OUR TS AND CS

MEDIA24 PRIVACY POLICY

VULNERABILITY DISCLOSURE

Follow:

Facebook

Eskom X9 0152

MEDIA STATEMEN

LOAD REDUCTION – NORTH WEST

Friday, 26 November 2021: To avoid overloading the Eskom network and damage infrastructure in high-density areas prone to network overloading, Eskom will implement **load reduction during evening peak hours on 26 November 2021.**

The implementation of load reduction will affect areas, and time is as follows:

Time	Main Area	Sub areas
	Evening peak	
17:00 – 22:00	**Rustenburg Sector**	Bethanie, Modikwe, Barseba Oskraal Village
17:00 – 22:00	**Klerksdorp, Mmabatho & Vryburg Sector**	Bokone, Koikoi Village, Mocoseng, Phefeni, Tar, Lerwaneng, Magogwe Center, Tlhabologo Village, Lethwanyeng, Magogong, Majaneng, Maphoitsile, Modutung, Mokasa, Roma - Taung, Takapori Pella, Silwerkrans, Doringkloof Seshibitswe, Uitkyk, Koffiekraal Mmatau, Moubane

During the load reduction implementation, customers are urged to switch off all their electrical appliances to avoid possible damage due to power surges when supply returns. Failure to do so may lead to transformers trips or failures and damages to household appliances when supply is restored.

Communities are encouraged to report meter bypasses, illegal connections and vandalism of the electricity infrastructure on the Eskom Crime-Line number: 0800 11 27 22.

Please do not report this outage.

ENDS

Issued by: Eskom North West Operating Unit
Tel: +27 14 523 7118

Eskom

X10 0153

MEDIA STATEMENT

LOAD REDUCTION – NORTH WEST

Friday, 24 December 2021: To avoid overloading the Eskom network and damage infrastructure in high-density areas prone to network overloading, Eskom will implement **load reduction during morning peak hours on Saturday, 25 December 2021.**

The implementation of load reduction will affect areas, and time is as follows:

Time	Main Area	Sub areas
	Morning peak	
05:00 – 09:00	**Klerksdorp, Mmabatho & Vryburg Sector**	Khuma Ext 09 Ikakgeleng
05:00 – 09:00	**Rustenburg Sector**	Bapong Bapong Segwaelane and Makolokwe Villages Bapong, Mabalstad, Rietfontein, holfontein Marikana RDP and the Police station.

During the load reduction implementation, customers are urged to switch off all their electrical appliances to avoid possible damage due to power surges when supply returns.
Failure to do so may lead to transformers trips or failures and damages to household appliances when supply is restored.

Communities are encouraged to report meter bypasses, illegal connections and vandalism of the electricity infrastructure on the Eskom Crime-Line number: 0800 11 27 22.

Please do not report this outage.

ENDS

Issued by: Eskom North West Operating Unit
Tel: +27 14 523 7118

Eskom

X11 0154

MEDIA STATEMEN

LOAD REDUCTION – NORTH WEST

Tuesday, 28 December 2021: To avoid overloading the Eskom network and damage infrastructure in high-density areas prone to network overloading, Eskom will implement **load reduction during evening peak hours on 28 December 2021.**

The implementation of load reduction will affect areas, and time is as follows:

Time	Main Area	Sub areas
	Evening peak	
17:00 – 22:00	**Rustenburg Sector**	Bapong Bapong Segwaelane and Makolokwe Villages Bapong, Mabalstad, Rietfontein, holfontein Marikana RDP and the Police station.
17:00 – 22:00	**Klerksdorp, Mmabatho & Vryburg Sector**	Khuma Ext 09 Ikakgeleng

During the load reduction implementation, customers are urged to switch off all their electrical appliances to avoid possible damage due to power surges when supply returns. Failure to do so may lead to transformers trips or failures and damages to household appliances when supply is restored.

Communities are encouraged to report meter bypasses, illegal connections and vandalism of the electricity infrastructure on the Eskom Crime-Line number: 0800 11 27 22.

Please do not report this outage.

ENDS

Issued by: Eskom North West Operating Unit
Tel: +27 14 523 7118

22/12/2022-11:31:00 AM

Eskom X12 0155

MEDIA STATEMENT

LOAD REDUCTION – NORTH WEST

Thursday, 20 January 2022: To avoid overloading the Eskom network and damage infrastructure in high-density areas prone to network overloading, Eskom will implement **load reduction during morning peak hours on 21 January 2022.**

The implementation of load reduction will affect areas, and time is as follows:

Time	Main Area	Sub areas
	Morning peak	
05:00 – 09:00	**Klerksdorp, Mmabatho & Vryburg Sector**	Bokone, Koikoi Village, Mocoseng, Phefeni, Tar, Lerwaneng, Magogwe Center, Tlhabologo Village, Lethwanyeng, Magogong, Majaneng, Maphoitsile, Modutung, Mokasa, Roma - Taung, Takapori, Pella Silwerkrans, Doringkloof Seshibitswe, Uitkyk, Koffiekraal Mmatau, Moubane
05:00 – 09:00	**Rustenburg Sector**	Bapong Bapong Segwaelane and Makolokwe Villages Bapong, Mabalstad, Rietfontein, holfontein Marikana RDP and the Police station.

During the load reduction implementation, customers are urged to switch off all their electrical appliances to avoid possible damage due to power surges when supply returns. Failure to do so may lead to transformers trips or failures and damages to household appliances when supply is restored.

Communities are encouraged to report meter bypasses, illegal connections and vandalism of the electricity infrastructure on the Eskom Crime-Line number: 0800 11 27 22.

Eskom X13 0156

MEDIA STATEMENT

LOAD REDUCTION – NORTH WEST

Sunday, 20 February 2022: To avoid overloading the Eskom network and damage infrastructure in high-density areas prone to network overloading, Eskom will implement **load reduction during morning peak hours on 21 February 2022.**

The implementation of load reduction will affect areas, and time is as follows:

Time	Main Area	Sub areas
Morning peak		
05:00 – 09:00	**Rustenburg Sector**	Bapong Bapong Segwaelane and Makolokwe Villages Bapong, Mabalstad, Rietfontein, holfontein Marikana RDP and the Police station.

During the load reduction implementation, customers are urged to switch off all their electrical appliances to avoid possible damage due to power surges when supply returns. Failure to do so may lead to transformers trips or failures and damages to household appliances when supply is restored.

Communities are encouraged to report meter bypasses, illegal connections and vandalism of the electricity infrastructure on the Eskom Crime-Line number: 0800 11 27 22.

Please do not report this outage.

ENDS

Issued by: Eskom North West Operating Unit
Tel: +27 14 523 7118

22/12/2022-11:31:00 AM

Eskom

0157

X14

MEDIA RELEASE

Eskom KwaZulu-Natal will implement load reduction during peak hours on 28 August 2022

Saturday, 27 August 2022: Eskom wishes to notify customers that it will implement load reduction to prevent network overloading in high-density areas as indicated below. Overloading of networks leads to damage to the electricity infrastructure through explosions in overloaded transformers and mini-substations. It also poses danger to people and property in the affected communities. Currently, Eskom is battling to keep up with the increased equipment failure that is costing millions to repair.

Load reduction will take place **between 05h00 and 09h00** on **Sunday, 28 August 2022.**

Below is a list of the affected areas:

Main Area	Sub areas
Abaqulusi, Nqutu	Endumeni, Nqutu, Luvisi, Mkhonjane A, Mkhonjane F, Ndatshana, Thelezini, Emhlangeni, Haladu B, Matinda, Mkhonjane E, Mkhonjane C, Mafitleng A, Mkhonjane D, Mafitleng, Ndindindi, Mafitleng B
Hibiscus Coast	Bhomela, Dumezulu, Gamalakhe, Gcilima, Madakana, Mhlalandlini, Ngodini, Nkampini, Nkoneni, Nsimbini, Nyandezulu, Nyaniswesi, Qina-About, Woza
Hlabisa, Nongoma, Ulundi	Amatshamnyama, Bazaneni, Bhekumteto, Bhokweni A, Bhokweni B, Bombolo B, Cekeni, Dayeni B, Dengeni A, Dengeni B, Dindi A, Dindi B, Dongothuli A, Dongothuli B, Dongothuli C, Ebumba, Emakhalathini A, Emakhalathini B, Emakhalathini Mine, Emcebo Bukalini, Enkananeni A, Enkananeni B, Esiphambanweni, Folose, Gudu, Gwebu, Hawini, Hlambanyathi, Jikaza, Khenana A, Khenana B, Kuvukeni A, KwaDlabe, KwaHlabisa, KwaKati A, KwaKati B, KwaLindizwe A, KwaLindizwe B, KwaManzimakhulu, KwaMsushwana, KwaQunwane, KwaYiphethe A, Mabundeni, Manqashi, Maqhomfini, Matsheketsha A, Matsheketshe B, Mbanda A, Mbanda B, Mbanda C, Mbebe, Mbizaneni, Mgangado, Mganimbobo A, Mganimbobo B, Mgovuzo, Mkhwaneni A, Mpumulwana, Mpuqwini A, Mpuqwini B, Msunduze, Mthonjeni, Mthwadlana, Mvulazi A, Mvulazi B, Mvulazi C, Ncemaneni, Ngolotshe A, Ngwebu, Njampela A, Njampela B, Njampela C, Njojo A, Nkonjeni, Nkonjeni A, Nkonjeni B, Nkungwini A, Nkungwini B, Nkweme C, Nongoma, Nqotweni, Ntabankulu, Obhicini, Odengeni, Odishweni, Okhukho A, Okhukho B, Okledeni, Qubeni A, Qubeni B, Qunyaneni, Sidinsi, Sigangeni, Sinkonkonko, Siphethu A, Siphethu B, Siphina, Sikazi, Tshonono Nongoma, Ulundi, Umfolozi Game Reserve, Vimbisikhala, Vilani, Vuthela, Wela A, Wela B, White City, Xasana, Xolo
Indaka	Entabeni, Ethoieni, Klippoort, Limehill, Madlala, Uitval Closer Settlement, Uitvlugt
Ingwe	Eziphahleni, Ezitendeni, Hlafuna, Ingwe, KwaSandanezwe, Mbulweleni, Ememela, KwaMnyamana, Mahoho, Nkwezela, Senkwanzela, Sizanenjana
Mpofana, Msunduzi, Richmond	Emaswazini, Imbali, Khokwane, KwaMncane, KwaNomo, KwaPata, Mbabane, Mbumbane, Mount Partridge, Mpofana, Nkabini, Nzondweni, Plessis-Laer, Richmond, Songonzima, Wilgerfontein, Emvundlini, KwaShange, KwaNtonqotho, Enqabeni, KwaMpande
Ndwedwe, uMshwathi, Umvoti	Abebhuzi, Chibini, Cuphulaka, Dalibha, Dayingubo, Etsheni, Ksikotho Mbalenhle, KwaDeda, Mbhava, Nambithani, Ndwedwe, Newspaper, Ngabayena, Ophokweni A, Ophokweni B, Swidi
Newcastle	Blaauwbosch Laagte, Jakkalspan, Johnstown, Leslie, Madadeni, Madadeni N, Massondale, Musikraal, Suspense
Richmond	Kupholeni, KwaCebelele, KwaMagoda, Ndaleni, Richmond, Springfield, Siyathuthuka
Umdoni	Bhudubhudu, Esperanza, Mafithini, Mhlangamkhulu, Pennington
Umhlabuyalingana	eKuhlupheleni, eNgozini, Kosi Bay Lodge, KwaGeorge, KwaMahlunguia,KwaMazambane, Mahlungulu, Manguzi B, Mvutshana
uMhlathuze, uMlalazi	Amanzamnyama, Caluza, Elomoya, Eniwe, Eziqaqweni, Felixton, Izinkilijl, Kwa-Mpofu, Macekana, Mandawe, Mbangayiya, Mbiza, Mhlathuzana,Mpehlela, Mtilombo, Ndabanyeni, Ngeza, Ngwelezane, Nkume, Nqutshini, Nsiwa, Siqwanjana, Thintumkhaba, uMlalazi, Vulindlela, Zenzele, Zimpohlo
Umzimkhulu	Dryhoek, Germiston, Gudlintaba, Gujedlini, KwaMakhanya, Mabuyana, Maduna, Marwaqa, Matshitshi, Mfulamhle, Nazareth A, Nguse, Nodwengu, Nongidi, Nyaka, Nyaniswesi, Nyembe, Sicelweni, St Barnabas, Ubuhlebezwe, Zadungeni

Customers from affected areas are encouraged not to log a fault during this period.

Eskom urges customers to treat all installations as live. Customers are advised to report any illegal activities on Eskom lines on the **Eskom Crime Line number: 0800 11 27 22.**

Ends

Issued on behalf of CentralEast Cluster (KZN Province) by:

Joyce Zingoni
Industry Support and Stakeholder Manager (ISSM) – CentralEast Cluster
Tel: 031 710 5775 | Fax: 086 667 1429 | Email: ZingonJ@eskom.co.za

X15 0158

NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

Licence Number: NERSA/ESKOM/TX/698-1301

LICENCE FOR THE OPERATION OF NATIONAL TRANSMISSION NETWORK

This licence is issued by the National Energy Regulator of South Africa, hereinafter referred to as the "Energy Regulator", in terms of the Electricity Regulation Act, 2006 (Act No. 4 of 2006).

This licence is issued to

Eskom Holdings SOC Ltd

(Company Registration No: 2002/015527/06)

hereinafter referred to as "the Licensee". This licence is only for the purpose of operation of the Transmission Network within the national boundaries of the Republic of South Africa.

The operation of the transmission network permitted under this licence is subject to the terms and conditions as contained in this licence and/or amendments to these conditions as imposed by the National Energy Regulator.

First issued on 31 August 1995
Amended on 19 February 2004

Re-issued at Pretoria on this **24th** day of **March 2017**.

CHIEF EXECUTIVE OFFICER
NATIONAL ENERGY REGULATOR

NATIONAL ELECTRICITY REGULATOR
TRANSMISSION LICENCE

Issued in terms of Section 6 of the Electricity Act (Act No. 41 of 1987 as amended) hereinafter referred to as "the Act".

NATIONAL TRANSMISSION LICENCE NO. 1
(Variation 2)

The National Transmission licence No. 1 which was granted to Eskom on 31 August 1995 is hereby amended in terms of Section 11 of this Licence, to cater for:

a) the amended legal status of Eskom;
b) the changes in Eskom operations;
c) enhanced regulatory requirements;
d) the promotion of competition in the electricity supply industry by, among others, permitting open and non-discriminatory access to the national transmission system - as defined more specifically in the **Grid Code, (listed in the Appendix),** the terms of which are specifically incorporated herein. This amended licence is granted to:

Eskom Holdings Ltd
Reg. No. 2002/015527 06
(Hereinafter referred to as "the Licensee")

only for

the operation of its Transmission Division, which must be conducted in the area as defined in Schedule 1 Part 1 and which business shall be conducted as the National Transmission Company, with the assets as defined in the **Appendix** attached and in accordance with the prescripts contained in this licence. This licence shall be effective for this business unit of the Licensee until it is properly incorporated, either as a wholly owned subsidiary of the Licensee or until incorporated as a separate, national, state-owned transmission company (the NTC).

The conduct of this operating division under this licence is subject to the conditions as identified below, or later revisions to these conditions as are approved by the National Electricity Regulator (hereinafter referred to as the NER) and which must be adhered to, in terms of Section 12 of the Act.

Copies of authorised revisions of the documents listed in the Appendix as well as copies of other authorised procedures identified by the NER and the revisions of these, must be submitted to the NER within thirty (30) days of their authorisation.

CONDITIONS OF ISSUE OF LICENCE

1. DEFINITIONS AND INTERPRETATION

In this licence, words and phrases, shall have the meaning ascribed to them in the definition section of this licence in Schedule 1 Part 2 and must be interpreted in accordance with the rules for interpretation contained in Schedule 1 Part 3.

2. GRANT OF LICENCE

The **National Electricity Regulator**, in exercise of the powers conferred by section 6 of the Act, hereby licenses **Eskom Holdings Limited** (hereinafter referred to as **"the Licensee"**) to operate a Transmission Division in the area designated in Schedule 1 Part 1, as the National Transmission Company. The prescribed undertakings of the Licensee for this operating division are as defined in section 4 of this licence.

3. TERM OF LICENCE

This licence shall come into force on (**1 April 2004**) and shall continue unless modified or revoked in accordance with the provisions of section 11 and 12 of this licence, to accord with government policy.

4. PRESCRIBED SERVICES OF LICENSEE

The licensee shall conduct the Transmission Division of its business to undertake the following key activities for the electricity supply industry, namely that of **Transmission Network Service Provider**, **System Operator**, **Transmission System Planner**, **Grid Code Secretariat** and the **Integrated Resource Planner**, with the responsibilities as set out below.

The licensee may only conduct any other business with the Transmission Division, including business with the regulated assets constituting Transmission System, subject to the approval of the NER.

The terms on which the Licensee, in conducting its business under this Licence, provides any other service, other than those prescribed above, must be fair and reasonable.

Any question as to the fairness or reasonableness of such terms shall be decided by the NER on the basis of the NER's opinion of the fairness or reasonableness of the terms.

The Transmission Division, in conducting its business under this Licence is prohibited from buying and selling energy, other than for its own use.

4.1 THE TRANSMISSION NETWORK SERVICE PROVIDER (TNSP)

4.1.1 The Transmission Division shall, operate and maintain the Licensee's assets constituting its transmission network in accordance with the **Grid Code** in order to transmit electricity across the **Transmission System** within the area designated in schedule 1.

4.1.2 The Licensee may own, operate/ or maintain defined transmission transformation equipment and assets on the Distribution System as agreed with **customers**.

4.1.3 The Licensee is obliged to make an offer to connect onto its transmission network or to increase the capacity of an existing connection to:

a) A holder of a generation, distribution network or transmission network licence, or a person who has been exempted by the **NER** from holding any of these licences.

b) A person which is, or intends to become, a **customer** taking supply directly from the Licensee's transmission network subject to:

- Receiving a request to do so with all the necessary information;
- The **customer's** ability to pay for the service requested; and
- Relevant technical constraints to be determined through consultation with such person(s).

4.1.4 The Licensee shall deal with such requests for connection in accordance with the **Grid Code**.

4.1.5 The Licensee shall, through its Transmission Division, offer to enter into connection agreements within:

a) The time periods specified in the **Grid Code**; or

b) Such other period as the **NER** decides to be reasonable.

4.1.6 The Transmission Division shall enter into operating agreements with all entities connected to the Licensee's transmission network, defining their reciprocal obligations, in accordance with the **Grid Code**.

TA

4.2 THE SYSTEM OPERATOR (SO)

4.2.1 The Transmission Division shall control the operation of and be responsible for the short-term reliability of the interconnected power system (IPS) as defined in the **Grid Code**. In so doing the Licensee shall act in accordance with the prevailing **Grid Code** and **Market Rules** in order to:

a) Ensure system reliability, safety and security;
b) Dispatch generation;
c) Set operational procedures;
d) Control the operations of the **IPS**;
e) Acquire sufficient **ancillary services**;
f) Provide operational information to the industry and
g) Define, on an annual basis in agreement with **customers**, the demarcation for the **IPS** (Schedule 4).

4.2.2 In execution of its responsibility for system reliability, the Transmission Division shall have authority over the operation of the IPS, in accordance with the provisions of this licence, the **Grid Code** and **Market Rules**.

4.2.3 The Licensee shall ensure non-discriminatory access to users of the Transmission System.

4.2.4 The Licensee shall, through its Transmission Division, offer to enter into use-of-system agreements within:
a) The time periods specified in the **Grid Code**;
b) Or such other period as the **NER** decides to be reasonable.

4.2.5 No person shall be entitled to access the **Transmission System** unless that person has agreed to pay a reasonable charge. The **NER** shall approve the methodology for the determination of a reasonable charge.

4.2.6 The Licensee shall facilitate the export and imports of electricity in accordance with whatever agreements may exist regarding international energy trading.

4.3 TRANSMISSION SYSTEM PLANNER (TSP)

4.3.1 The Licensee shall, through its Transmission Division, plan and augment the **Transmission System** in accordance with the **Grid Code**.

4.3.2 **Augmentation** shall take place subject to:

a) A connection agreement with a **customer** where a new connection or extension to an existing connection is made.
b) If the Transmission Division determines that **augmentation** of the **Transmission System** is required, the TNSP shall augment the **Transmission System** in accordance with efficient business and procurement practices.

4.4 GRID CODE Secretariat

4.4.1 The System Operator within the Transmission Division is appointed as the **Grid Code Secretariat** in terms of the **Grid Code,** to be responsible for administering the application of the **Grid Code** for users of the **IPS** and recommending the appropriate changes to the Code, subject to the approval of the NER.

4.5 INTEGRATED RESOURCE PLANNER

4.5.1 The Licensee shall annually compile and publish a national indicative resource plan for the electricity supply industry, as directed by the **NER**.

5. SEPARATE ACCOUNTS FOR ELECTRICITY TRANSMISSION BUSINESSES

5.1 The Licensee, as a holding company, shall maintain separate and ring-fenced accounts for the elements of its Transmission Division as defined in schedule 3, so that the revenues; costs; assets; liabilities; reserves and provisions for, or reasonably attributable to the **transmission system** are separately identifiable in the books of the Licensee from those of any other business.

5.2 The Licensee shall prepare on a consistent basis from such accounting records in respect of the financial year of the Licensee, and each subsequent financial year, accounting statements comprising.
a) an income statement;
b) a balance sheet;

together with notes thereto, and in appropriate detail, the amounts of any revenue, cost, asset, liability, reserve or provision which has been charged from or to any other business together with a description thereof.

5.3 The Licensee shall annually submit audited copies of such accounting statements to the **NER** within 180 days of the end of the Licensee's financial year.

5.4 The conduct of any other business undertaking by the Licensee carrying on business under this licence shall be in accordance with sound ring-fencing principles applied to the conduct of such undertaking and shall further be in accordance with any guidelines as may be issued by the NER from time to time.

6. PRICES & TARIFFS

6.1 The **NER** shall approve the tariffs at which the Licensee shall charge for the use of its Transmission Network and for the connection of its **customers** to the Transmission Network. This tariff approval shall be done in accordance with transmission regulatory methodology published by the NER.

6.2 The Licensee is not permitted to charge any other tariffs than those specified in the schedule of approved tariffs set out in schedule 2 hereto, as revised from time to time, without the approval of the **NER**.

7. COLLECTION AND EXCHANGE OF INFORMATION

The **NER** shall be entitled to collect such information from the Licensee or its **customers**, as it deems necessary. The Licensee is further obliged to ensure that it provides such information as is necessary to **customers**, to facilitate the development of a market, in accordance with the prevailing **Grid Code** and or **Market Code**.

8. SETTLEMENT OF DISPUTES

8.1 The **NER** is entitled to settle disputes between the Licensee and its **customers** or prospective customers or any person affected by the operation of this undertaking regarding -

a) the right to transmit;
b) the provisions of the **Grid Code**;
c) the prices at which services are provided;
d) delays in or refusal to provide a service by the Licensee; and
e) any other matter in respect of which the Licensee or its consumers requests the **NER** to act as mediator.

8.2 Any decision of the **NER** on a dispute as contemplated in section 8.1 above is binding on the parties to the dispute.

9. PROHIBITION OF TRANSFER OF RIGHT TO PROVIDE A SERVICE

This licence is not transferable without the approval of the **NER**.

10. FAILURE TO CARRY OUT CONDITIONS OF LICENCE

The Licensee shall not derogate from the conditions contained in this licence with reference to the conduct of its Transmission Division under this licence for the provision of any services conducted under this licence, unless it can demonstrate good cause to the NER for such derogation.

The NER shall decide what constitutes good cause, by taking into account all matters pertinent to the case under consideration.

The Licensee shall also not, except for reasons beyond its control, reduce or discontinue the transmission of electricity to a **customer** unless –

a) the **customer** is insolvent; or
b) the **customer** has failed to pay the agreed charges or to comply with the conditions of service delivery and has failed to remedy the default within 14 days, or within such longer period as may be specified by the **NER**.

In the event of non-compliance by the Licensee with any of its duties and obligations under this Licence, NER may take any or all of the following enforcement actions:

(a) Issue a notice requiring the Licensee to remedy the breach within a set period;
(b) In the event of the breach not being remedied, issue such penalties as may be permitted by legislation or regulation;
(c) Require the Licensee to deliver a report by a set date, setting out the causes of the failure to comply with its duties and obligations, and the action taken to prevent a re-occurrence of the breach;
(d) Undertake an enquiry into the failure to comply. The Licensee shall co-operate with such enquiry and failure to co-operate shall be considered a further breach of its obligations;
(e) Issue directives as to how the Licensee shall in future act so as to prevent further failures to comply;
(f) Revoke the Licence in terms of Section 12 of this Licence.

11. MODIFICATION OF LICENCE

The **NER** may modify the conditions of this licence -

a) with the agreement of the Licensee; or

b) failing such agreement, after 30 days due notice has been given to the Licensee by the **NER** and after consideration of any representation or objections.
c) after due consideration of any representations made by the Licensee.

12. REVOCATION OF LICENCE

12.1 The **NER** may at any time agree with the Licensee that this licence should be revoked, in which case the term of the licence ends on the day agreed.

12.2 The **NER** may at any time give 30 days notice of revocation to the Licensee if the Licensee does not comply with any of its duties and obligations, and the Minister determines that it is necessary or desirable to revoke this licence, in which case the term of this licence ends on the expiration of the period of the notice. The term of this licence does not end at the expiration of the period of a notice of revocation given under this paragraph if, before the expiration, the Licensee complies with its duties or obligations.

13. POWERS OF ENTRY AND INSPECTION

The **NER**, or any person authorised by it in writing, may enter upon premises of the Licensee and be entitled to inspect any equipment, plant, machinery, books, accounts and other documents of the Licensee.

14. FURNISHING OF RETURNS

The **NER** may call upon the Licensee to furnish to it such periodical or other returns in such form as the **NER** may from time to time prescribe, and such particulars in respect of the undertaking as the **NER** may from time to time demand.

15. COMPLIANCE WITH LAWS AND REGULATIONS

The Licensee shall comply with all applicable laws and especially those governing the electricity supply industry including regulations, codes, directives, guidelines as effected from time to time.

The licensee shall transmit the electricity of its **customers** in accordance with the Power Quality directive and subject to such quality criteria, standards and directives as the **NER** may from time to time prescribe.

SCHEDULES

SCHEDULE 1 - PART 1

LICENCE AREA

Within the national boundaries of the Republic of South Africa.

SCHEDULE 1 - PART 2

DEFINITION SECTION

All words and expressions in the Transmission Licence shall bear the following meaning:

Augmentation
In relation to an electricity transmission system means, the process of maintaining or upgrading the operating capability of the electricity **transmission system** by replacing or enhancing existing plant and equipment or by adding plant and equipment.

Ancillary services
Services supplied to the Licensee by generators, distributors or end-use **customers**, necessary for the reliable and secure transport of power from generators to distributors and other customers.

Customer
A legal entity that contracts with the Licensee, for the provision of transmission services.

Eskom
Refers to Eskom Holdings Limited (Registered: 2002/015527/06) a Company registered in terms of the Company Laws of the Republic of South Africa, with its registered office at Megawatt Park, Maxwell Drive, Sandton.

Grid Code
The regulatory instrument approved by the NER and developed in consultation with electricity supply industry participants, which defines the technical and operational requirements for connecting to the interconnected power system and which consists of the following documents:

- Preamble
- Governance Code
- Network Code

- System Operation Code
- Metering Code
- Tariff Code
- Information Exchange Code

Grid Code Secretariat
The entity responsible for the administrative functions as defined in the Governance Code of the **Grid Code.**

Interconnected power system
A defined in the **Grid Code**

Market Rules
The rules by which participants must abide when participating in the South African electricity market. These are the rules that must be accepted by market participants and must be approved by the **NER**.

National Electricity Regulator (NER)
The legal entity established in terms of Section 2 of the Electricity Act (Act no. 41 of 1987 as amended), responsible for regulating the electricity supply industry in South Africa.

System Operator (SO)
The entity within the Licensee's Transmission Division responsible for the control and operation of the interconnected power system, in accordance with the **Grid Code.**

Transmission Network Service-Provider (TNSP)
The entity within the Licensee's Transmission Division, responsible for the control, maintenance and provision of all associated services for offering connection to users of the (IPS) / national electricity transmission network.

Transmission System (TS)
Is defined in the South African electricity supply industry as consisting of all lines and substation equipment where the nominal voltage is above 132 **kV**. All other equipment operating at lower voltages are either part of the distribution system or classified as transmission transformation equipment.

Acronyms / Abbreviations

kV	kilovolt
NER:	National Electricity Regulator
TNSP:	Transmission network service-provider
TS:	Transmission system
SO:	System Operator
IPS:	Interconnected Power System

SCHEDULE 1 – PART 3: RULES FOR INTERPRETATION

In this licence, unless the context otherwise requires:

(a) headings are for convenience only and do not affect the interpretation of this licence;

(b) words importing the singular include the plural and vice versa;

(c) an expression importing a natural person includes any company, partnership, trust, joint venture, association, corporation or other body corporate and any governmental agency;

(d) a reference to a condition, clause, schedule or part is to a condition, clause, schedule or part of this licence;

(e) a reference to terms of an offer or agreement is to all terms, conditions and provisions of the offer or agreement;

(f) a reference to a document or a provision of a document includes an amendment or supplement to, or replacement or novation of, that document or that provision of that document;

(g) a reference to a person includes that person's executors, administrators, successors, substitutes (including, without limitation, persons taking by novation) and permitted assigns;

(h) a period of time:

(1) which dates from a given day or the day of an act or event is to be calculated exclusive of that day; or

(2) which commences on a given day or the day of an act or event is to be calculated inclusive of that day; and

(i) an event, which is required under this licence to occur on or by a stipulated day, which is not a business day, may occur on or by the next business day.

SCHEDULE 2

TRANSMISSION PRICES AND TARIFFS

(This schedule must contain an updated list of the tariffs applied by the Licensee, as approved by the **NER**, in accordance with the principles set out in the Tariff Code section of the Grid Code.)

SCHEDULE 3

Transmission Business

The Transmission Division of the Licensee (Eskom Holdings Ltd), comprises of the following undertakings (as stipulated below), which are identified for separate accounting treatment, namely:

1. The Network Service Provider;
2. The System Operator;
3. The Transmission System Planner;
4. The Grid Code Secretariat; and
5. The National Indicative Resource Planner

SCHEDULE 4

Demarcation of Interconnected Power System

The Licensee shall provide a list or schedule defining all the assets that constitute the IPS.

APPENDIX

Item No.	Item	Date of Approval
1	National Transmission Licence no. 1	31 Aug 1995
2	Grid Code version x	June 2003
3	Eskom Holdings Ltd – List of defined transmission assets	
4	Operating procedures in terms of the Grid Code	
5	Planning procedures in terms of the Grid Code	

0173

X16

NATIONAL ELECTRICITY REGULATOR

TEMPORARY DISTRIBUTION LICENCE

issued to

ESKOM HOLDINGS (PTY) LTD
Reg. No. 2002/015527/06

NER/D//ESK

1. DEFINITIONS AND INTERPRETATION

In this licence, words and phrases shall have the meaning ascribed to them in the definition section of the Electricity Act, 1987 (Act No. 41 of 1987) (hereinafter referred to as the Act) and the definition section of the Grid Code, as applicable.

2. GRANT OF LICENCE

The National Electricity Regulator, in exercise of the powers conferred by section 6 of the Act, hereby licenses Eskom to distribute and supply electricity to all consumers of electricity within the area designated in schedule 1 below, subject to the conditions set out in this licence and the Act, read together with the Grid Code.

2.1 NON-GRID ELECTRIFICATION

As mandated by the Minister of Minerals and Energy, in accordance with subsection 4, clause 4 of the Electricity Act, No.41 of 1987, the NER licences ESKOM to function as an agent on behalf of the Department of Minerals and Energy in the implementation of Non-Grid Electrification. The following sections of this licence do not apply to non-grid electrification, as ESKOM's non-grid electrification business shall be regulated by the following list of signed contracts between the parties involved.

- *Agency agreement between the Government of the Republic of South Africa in its Department of Minerals and Energy and ESKOM for Non-Grid Electrification;*
- *Memoranda of Understanding signed between ESKOM and the selected Non-Grid Service Providers; and*
- *Customer agreement, performance criteria and performance guarantee of Non-Grid Service Providers.*

These contracts are attached as Schedule 2 to this licence.

Further, ESKOM shall notify the NER prior to the signing of any contracts with concessionaires to begin work in an area. This is merely for the purposes of coordination and control.

3. TERM OF LICENCE

This licence shall come in force on 1 July 2006 until 30 June 2007 subject the establishment of the proposed Regional Electricity Distributors.

4. DUTIES OF LICENSEE

4.1 The licensee shall supply electricity within the area of supply mentioned in schedule 1 below to every applicant who is in a position to make satisfactory arrangements for payment thereof.

4.2 Where the licensee is undertaking an electrification programme which has been approved in terms of the Integrated National Electrification Programme (INEP), and the programme sets out the approximate dates on which potential consumers will receive their electricity supply, the licensee shall supply electricity to such potential consumers in accordance with the approved electrification plan.

5. CONDITIONS OF LICENCE

The licensee shall be bound by the following conditions to this licence:

5.1. LEGAL CONDITIONS

5.1.1 The licensee shall supply electricity within the area of supply mentioned in schedule 1 below to every applicant who is in a position to make satisfactory arrangements for payment thereof.

5.1.2 The licensee shall comply with the Grid Code insofar as the Code applies to any of its operations, except where exemptions and derogations have from time to time been approved by the NER. To this end the Licensee shall ensure that all connection and use of system contracts with the Licensed Transmitter are compliant with the Grid Code.

5.1.3 The licensee shall not reduce or discontinue the supply of electricity to a consumer unless -

i) the consumer is insolvent ; or

ii) the consumer has failed to pay the agreed charges or to comply with the conditions of supply and has failed to remedy the default within 14 days after receiving from the licensee a written notice by post calling upon him to do so.

5.1.4 Where the licensee is undertaking an electrification programme which has been approved based on a one year fixed and three year rolling programme in terms of the Integrated National Electrification Programme, the licensee's programme shall set out the approximate dates on which potential consumers will receive their electricity supply, the licensee shall supply electricity to such potential consumers in accordance with the approved electrification plan.

5.1.5 The National Electricity Regulator shall be entitled to settle disputes between the licensee and another supplier, or between the licensee and its consumers or prospective consumers regarding -

- i. the right to supply;
- ii. the quality of such supply and the provision of services in connection therewith;
- iii. the condition on and prices at which electricity is supplied;
- iv. the installation and functioning of meters;
- v. the suitability of the equipment of the licensee;
- vi. delays in or refusal to supply by the licensee;
- vii. any other matter in respect of which the licensee or its consumers requests the National Electricity Regulator to act as mediator.

5.1.6. Any decision of the regulator on a dispute as contemplated in 5.1.5 above is binding on the parties to the dispute.

5.1.7. This licence is not transferable without the approval of the National Electricity Regulator.

5.2 FINANCIAL CONDITIONS

5.2.1 The licensee shall maintain separate electricity distribution business affairs from the licensee's other affairs so that the revenues; cost; assets; liabilities; reserves and provisions for the electricity business are separately identifiable in the books of the licensee from those of any other business.

5.2.2 The licensee shall prepare on a consistent basis from such accounting records in respect of the financial year of the licensee, and each subsequent financial year, accounting statements comprising -

- i. an income statement;
- ii. a balance sheet.

together with notes thereto, and in appropriate detail the amounts of any revenue, cost, asset, liability, reserve or provision which has been charged from or to any other business together with a description thereof.

5.2.3 The licensee shall annually submit audited copies of such accounting statements to the National Electricity Regulator within 180 days of the end of the licensees financial year. This shall include an asset register, purchase value and current value.

5.2.4 The National Electricity Regulator shall determine the prices at which the licensee shall supply electricity to its consumers.

5.2.5 The licensee is not permitted to charge any consumers with other tariffs than those specified in the schedule of approved tariffs set out in schedule 2 hereto, as revised from time to time, without the approval of the National Electricity Regulator.

5.2.6 The licensee shall pay the bulk supplier from whom it purchases its electricity.

5.2.7 Ensure that monies allocated for statutory National Electricity Regulator purposes in the licensee's budget are utilised for such purposes.

5.2.8 Ensure that electricity tariffs increases are promulgated through appropriate media.

5.3 TECHNICAL CONDITIONS

5.3.1 The licensee shall supply electricity to its consumers in compliance with quality standards/criteria as the National Electricity Regulator may from time to time prescribe such as:

- i. Maintenance policy and schedules as prescribed by the NRS 082;
- ii. Code of practice for electricity metering NRS 057; and
- iii. Standards of Service (NRS 047) and quality (NRS 048).

5.3.2 Prepare and adhere to plans, which protect customers and ensure the effectiveness of the industry such as:

- i. Maintenance Schedules;
- ii Standards of Service (NRS 047) and Quality (NRS 048);
- iii enquiries and complaints management;
- iv license compliance management;
- v consumer/public and staff safety/education; and
- vi system losses reduction.

5.3.3 The Licensee shall comply with any NER requirements for the incorporation of any energy efficiency and demand management strategies before augmenting or expanding a distribution system.

5.3.4 Ensure that metering, billing and revenue collection are effective, efficient and accurate.

5.4 GENERAL CONDITIONS

5.4.1 The National Electricity Regulator shall be entitled to collect such information from the licensee or its consumers as it deems necessary.

5.4.2 The licensee shall supply the NER on a quarterly basis with new electrification connections completed during the previous three months, starting in April of each year.

5.4.3 The National Electricity Regulator, or any person authorised by it in writing, may enter upon premises of the licensee and inspect any plant, machinery, books, accounts and other documents found there.

5.4.4 The National Electricity Regulator may call upon the licensee to furnish to it such periodical or other returns in such form as the National Electricity Regulator may from time to time prescribe, and such particulars in respect of the undertaking as the National Electricity Regulator may from time to time demand.

6. FAILURE OF LICENSEE TO MEET OBLIGATIONS IN TERMS OF THIS LICENSE

6.1 If any licensee fails to meet his obligations in terms of this license, the National Electricity Regulator may serve upon him by post a notice in writing to meet those obligations within 30 days or such longer period as the Regulator may determine, and if the licensee fails to comply with the requirements of the notice-

i. it shall be guilty of an offence and upon conviction be punishable as provided for in the Act;

ii. the Regulator may recommend to the Minister to authorise an appropriate undertaker to enter upon and take possession of the undertaking of the licensee;

iii. the Regulator may withdraw the licence at any time.

7. MODIFICATION OF LICENCE

The conditions of this licence may be modified by the National Electricity Regulator -

i. with the agreement of the licensee ; or

ii. failing such agreement, after 30 days due notice has been given to the licensee by the National Electricity Regulator and after consideration of any representation or objections.

8. REVOCATION OF LICENCE

8.1 The National Electricity Regulator may at any time agree with the licensee that this licence should be revoked, in which case the term of the licence ends on the day agreed.

8.2 The National Electricity Regulator may at any time give 30 days notice of revocation to the licensee if the licensee does not comply with any of its duties and obligations, and the Minister determines that it is necessary or desirable to revoke this licence, in which case the term of this licence ends on the expiration of the period of the notice. The term of this licence does not end at the expiration of the period of a notice of revocation given under this paragraph if, before the expiration, the licensee complies with its duties or obligations.

SIGNED:

Chief Executive Officer

DATE: 24/08/06.

NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

ESKOM'S ELECTRICITY DISTRIBUTION LICENCE SCHEDULES

LICENCE No.: NER/D/ESKOM

SCHEDULE 1

a) Supply Area - Grid

The presently licensed area(s) electrified and supplied by ESKOM as depicted by Geographic Information System (GIS) polygons. Customers being supplied by municipality or any other Licensed Distributor at the date of commencement of this licence are excluded from this licence.

List of Supply Areas

The Licensed Supply Areas are stated below by provinces and per specific municipality including area names, towns, suburbs, villages and townships including township extension where necessary, which are:

1. Northern Cape **(Annexure 1)**;
2. Free State **(Annexure 2)**;
3. Eastern Cape **(Annexure 3)**;
4. North West **(Annexure 4)**;
5. Western Cape **(Annexure 5)**;
6. Mpumalanga **(Annexure 6)**;
7. Limpopo **(Annexure 7)**;
8. Kwa Zulu Natal **(Annexure 8)**; and
9. Gauteng **(Annexure 9)**.

b) Supply Area – Non-Grid

The supply areas with respect to non-grid electrification are strictly those that have been agreed to by Government and are stated below:

The concessions areas are:

1. Eastern Cape/Kwa-Zulu Natal (DC21, DC15, CBDC5, but excluding EC157)
2. Eastern Cape (DC12, EC157)
3. Northern Province (DC34, DC35, CBDC3)
4. Central Kwa-Zulu Natal (DC22, DC23, DC24, DC29)
5. Northern Kwa-Zulu Natal (DC25, DC26, DC27, DC28)

SCHEDULE 2 Tariffs and Prices

As approved by the National Energy Regulator of S.A.

SCHEDULE 3 Amendments

Item No.	Amendment	Date of Approval
1	First issue to Eskom	August 1995
2	Transfer of electricity distribution licence from BECOR to Eskom	21 November 1996
3	Amendment of Eskom's electricity distribution licence to exclude Portion 2 of the farm Hartebeesfontein No 422 IP in Stilfontein Municipality	22 November 1996
4	Accommodation of re-determination of cross boundary municipalities	July 2001
5	Amendment of Eskom's distribution license to include Dan Sandi View Township	21 August 2003
6	Transfer of electricity distribution licence from Nongoma Local Municipality to Eskom	October 2003
7	Amendment of the licence to include Dududu, Turton and Maguntia from Port Shepstone Municipality	29 April 2004
8	Transfer of Rosherville Properties (Pty) Ltd electricity distribution licence to Eskom	8 December 2005
9	Amendment of the licence to include Tigerkloof, Brussels, De Beers, Dryharts and Pudimoe from Naledi Municipality	7 August 2006
10	Extension of licence validity period until 30 June 2006	26 May 2006
11	Extension of licence validity period until 36 month after the promulgation of the relevant licensing regulations made under the ERA.	June 2007
12	Amendment of Eskom's electricity distribution licence to exclude Carsdale village in uMhlathuze Municipality	31 July 2007
13	Amendment of Eskom electricity distribution licence to exclude Felixton area village in uMhlathuze Municipality	28 March 2008
14	Amendment of the licence to exclude Komati village in Steve Tshwete Municipality	28 March 2008
15	Amendment of the licence to exclude Ingwavuma town in uMkhanyakude District Municipality	24 March 2010
16	Amendment of the licence to include the following areas from AECI Limited (Somerset West) area of supply into Eskom Western region, which are: a) Portion 56, Farm 794 Stellenbosch; b) Portion 119, Farm 794 Stellenbosch; c) Remaining portion, Farm 787 Stellenbosch; d) Erf 15850 of Somerset West;	27 May 2010

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA GAUTENG DIVISION, PRETORIA
Private Bag X67, Pretoria 0001
REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA GAUTENG DIVISION, PRETORIA

	e) Erf 15851 of Somerset West; and f) Erf 15852 of Somerset West;	
17	Amendment of the licence to include Ngwanallela Village in the electricity supply area from Blouberg Local Municipality	24 November 2011
18	Amendment of Schedule 1 to reflect exact areas of electricity supply with corresponding Geographic Information System (GIS) polygons for Northern Cape Province.	5 April 2017

Signed at Pretoria on this 8TH day of ……MAY……2017

Chris Forlee
CHIEF EXECUTIVE OFFICER

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA
Private Bag X67, Pretoria 0001
REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA

Eskom Northern Cape Anenxure 1

[illegible]	[illegible]	[illegible]	[illegible]
!Kheis Local Municipality	NC084	Groblershoop	NED000751
		Sternheim	NED000752
		Grootdrink	NED000753
		Boegoeberg	NED000754
		Gariep	NED000755
		Kleinbegin	NED000756
		Topline	NED000757
		Wegdraai	NED000758
Dawid Kruiper Local Municipality	NC083	Ntsikelelo	NED000698
		Straussburg	NED000699
		Andriesvale	NED000727
		Askham	NED000728
		Groot Mier	NED000729
		Kameelduin	NED000732
		Karos	NED000734
		Klein Mier	NED000735
		Lambrechtsdrift	NED000738
		Leerkrans	NED000739
		Loubos	NED000741
		Melkstroom	NED000744
		Phillandersbron	NED000745
		Raaswater	NED000746
		Rietfontein	NED000747
		Welkom	NED000750
Dikgatlong Local Municipality	NC092	Mataleng	NED000273
		Rooirand	NED000274
		Tidimalo	NED000278
		Corn's Village	NED000279
		Hebron Park	NED000280
		Kutlwano	NED000281
		Windsorton	NED000282
		Gong-Gong	NED000283
		Holpan	NED000284
		Koopmansfontein	NED000285
		Pniel	NED000287
		Pniel Estates	NED000288
		Stillwater	NED000289
		Waldeck's Plant	NED000292
Emthanjeni Local Municipality	NC073	Kwezi	NED000362
		Nompelelo	NED000363
		Tornadoville	NED000364

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA
Private Bag X67, Pretoria 0001
REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA

Gamagara Local Municipality	NC453	Diepkloof	NED000397
		Ditloung	NED000398
		Skerpdraai	NED000400
		Dibeng	NED000403
Ga-Segonyana Local Municipality	NC452	Batlharos	NED000408
		Batlharos RDP	NED000409
		Ditshoswaneng	NED000410
		Ga-Lotolo	NED000411
		Gamopedi	NED000412
		Ga-Motsamai	NED000413
		Gantatelang (Dikgweng)	NED000414
		Garuele (Mosekeng Sou	NED000415
		Ga-Sebolao	NED000416
		Ga-Sehubane	NED000417
		Geelboom	NED000418
		Kagung	NED000419
		Magobe	NED000420
		Magobe RDP	NED000421
		Mapoteng	NED000422
		Maruping	NED000423
		Mokalamosesane	NED000424
		Mothibistat	NED000425
		Mothibistat RDP	NED000426
		Ncweng	NED000427
		Piet Bos	NED000428
		Sedibeng	NED000429
		Seoding	NED000430
		Seoding RDP	NED000431
		Seven Miles (Mmamora	NED000432
		Slojah	NED000433
		Thamonyanche	NED000434
		Vergenoeg (Maheane)	NED000435
Hantam Local Municipality	NC065	Rondomskrik	NED000674
		Calvinia West	NED000676
		Loeriesfontein Ext 1	NED000678
		Middelpos	NED000680
		Baily Birts	NED000436
		Battlemount	NED000437
		Bendel	NED000438
		Bojelapotsane	NED000440
		Bosra	NED000441
		Bothetheletsa	NED000442
		Bothithong	NED000443
		Bothithong RDP	NED000444
		Bushy Park	NED000445
		Cahar	NED000446
		Camden	NED000447
		Camden RDP	NED000448

Cardington	NED000449
Cassel	NED000450
Churchill	NED000451
Colston	NED000452
Damros 1	NED000453
Damros 2	NED000454
Damrose 3	NED000455
Danoon	NED000456
Deurham	NED000457
Deurward	NED000458
Dikhing	NED000459
Dinyaneng (Dockson 2)	NED000460
Dithakong	NED000461
Ditlharapaneng	NED000462
Ditshilabeleng	NED000463
Ditshipeng	NED000464
Diwatshane	NED000465
Dockson	NED000466
Drieloop	NED000467
Eiffel	NED000468
Ellendale (Smauswane)	NED000469
Esperanza (Churchill)	NED000470
Gadiboe (Tlhokomelang	NED000484
Gahue (Gamatolong)	NED000485
Gakhoe (Gahuhuwe)	NED000486
Galotlhare	NED000487
Ga-Madubu	NED000471
Ga-Makgatlhe	NED000472
Ga-Masepa	NED000473
Gamasilabele	NED000488
Gamatolong	NED000489
Ga-Mmokwane	NED000474
Ga-Moheete (Dithakong	NED000475
Gamokatedi	NED000490
Ga-Mokomela (Dithakor	NED000476
Gamorona	NED000491
Ga-Mothibi	NED000477
Ganap	NED000492
Ganghae	NED000493
Ga-Sehunelo Wyk 5 (Ga-	NED000478
Ga-Sehunelo Wyk 6	NED000479
Ga-Sehunelo Wyk 7	NED000480
Ga-Sehunelo Wyk 8	NED000481
Ga-Sehunelo Wyk 9 (Els	NED000482
Gasese	NED000494
Ga-Thameng (Wateraar	NED000483
Gatshekedi	NED000495
Gatswinyane	NED000496

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA GAUTENG DIVISION, PRETORIA
Private Bag X67, Pretoria 0001
REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA GAUTENG DIVISION, PRETORIA

		Glenred	NED000497
		Glenred RDP	NED000498
		Goodhope	NED000499
		Heiso	NED000500
		Hertzog	NED000501
		Heuningvlei	NED000502
		Heuningvlei Pan	NED000503
		Kakonye	NED000505
		Kampaneng	NED000506
		Kanana	NED000507
		Kelokeloe	NED000508
		Kganung	NED000509
		Kganwane	NED000510
		Kgomohute	NED000511
		Kgomohute 2	NED000512
		Khankhudung	NED000513
		Kiangkop	NED000514
		Kikahela	NED000515
		Kilo-Kilo	NED000516
		Klein Eiffel	NED000517
		Kleineira	NED000518
		Kliphom	NED000519
		Kokfontein (Khabetlwar	NED000520
		Kokonye	NED000521
		Kome (Bareki)	NED000522
		Kortnight	NED000523
		Kruisaar	NED000524
		Laxey	NED000525
Joe Morolong Local Municipality	NC451	Lebonkeng	NED000526
		Letlhakajaneng	NED000527
		Logaganeng	NED000529
		Logaganeng	NED000528
		Logobate	NED000530
		Lokaleng	NED000531
		Longhurst	NED000532
		Loopeng	NED000533
		Lotlhakane	NED000534
		Madibeng	NED000535
		Magagwe	NED000536
		Magobing West	NED000537
		Magojaneng	NED000538
		Mahukubung	NED000539
		Maipeng	NED000540
		Majanking (Dithakong)	NED000541
		Majemantsho	NED000542
		Makadibeng (Kokfontei	NED000543
		Maketlele	NED000544
		Makgaladi	NED000545

Makhubung	NED000546
Mamebe	NED000547
Mammehe	NED000548
Manaring	NED000549
Manyeding	NED000550
Maolagane	NED000551
Maphiniki	NED000552
March	NED000553
Masankong	NED000554
Maseohatshe	NED000555
Masilabetsane	NED000556
Mathanthanyaneng	NED000557
Matlhabanelong	NED000558
Matolwaneng	NED000559
McCarthysrus	NED000560
Mentu	NED000561
Metsimantsi Wyk 1	NED000562
Metsimantsi Wyk 2	NED000563
Metsimantsi Wyk 3	NED000564
Metsimantsi Wyk 4	NED000565
Metsimantsi Wyk 6	NED000566
Metswetsaneng	NED000567
Mmatoro	NED000568
Mokalawanoga	NED000569
Molatswaneng	NED000570
Mosekeng	NED000571
Moshaweng	NED000572
Motlhoeng	NED000573
Ncwelengwe	NED000574
Niks	NED000575
Nkajaneng	NED000576
Ntswaneng	NED000577
Padstow	NED000578
Penryn	NED000579
Perdmontjie (Molomow	NED000580
Perth	NED000581
Phomolong	NED000582
Pietersham (Makalanen	NED000583
Pong-Pong	NED000584
Radiatsogwa	NED000585
Ramatale	NED000586
Rusfontein Wyk 10 (Pho	NED000587
Rusfontein Wyk 11 (Pho	NED000588
Rusfontein Wyk 9 (Phon	NED000589
Ruwell	NED000590
Saamsukkel	NED000591
Salaneng (Dithakong)	NED000592
Segwaneng	NED000593

		Sesipi	NED000594
		Setswetshaneng	NED000595
		Severn	NED000596
		Shalaneng	NED000597
		Skerma	NED000598
		Slough (Sloujah)	NED000599
		Stilrus	NED000600
		Suurdig	NED000601
		Takeng (Selosesha)	NED000602
		Tlapeng	NED000603
		Tsaelengwe	NED000604
		Tsiloane (Tsilwana)	NED000605
		Tsineng	NED000606
		Tsineng-Kop	NED000607
		Tsoe	NED000608
		Tzaneen	NED000609
		Van Zylsrus	NED000610
		Washington	NED000611
		Wateraar	NED000612
		Wingate	NED000613
		Zero (Thotayamokhu)	NED000614
Kai !Garib Local Municipality	NC082	Augrabies	NED000760
		Augrabies Ext 1	NED000761
		Augrabies Ext 2	NED000762
		Lennertsville	NED000773
		Alheit	NED000775
		Bloemsmond	NED000776
		Cillie	NED000777
		Currie's Camp	NED000778
		Kanoneiland	NED000779
		Loxtonvale	NED000780
		Lutzburg	NED000781
		Marchand	NED000782
		Sending	NED000783
		Soverby	NED000784
		Vredesvallei	NED000785
Kamiesberg Local Municipality	NC064	Kharkams	NED000793
		Leliefontein	NED000797
		Tweerivier	NED000804
Kareeberg Local Municipality	NC074	Bonteheuwel	NED000382
		De Bult	NED000384
		Ou Skema	NED000385
		Van Wyksvlei	NED000386
		Van Wyksvlei West	NED000387
		Skietfontein	NED000392
Karoo-Hoogland Local Municipality	NC066	Rebelskop	NED000627
		Sutherland	NED000628
		Amandelboom	NED000629

Khâi-Ma Local Municipality	NC067	Melkbosrand	NED000633
		Onseepkans	NED000634
		Sending	NED000635
		Viljoensdraai	NED000636
		Pella	NED000640
		Witbank	NED000641
Magareng Local Municipality	NC093	Ikutseng	NED000293
Nama Khoi Local Municipality	NC062	Buffelsrivier	NED000661
		Bulletrap	NED000662
		Goodhouse	NED000665
		Henkries	NED000667
		Komaggas	NED000669
		Rooiwal	NED000670
		Steinkopf	NED000671
		Vioolsdrif	NED000672
Phokwane Local Municipality	NC094	Andalusiaville	NED000260
		Kingston	NED000262
		Valspan	NED000263
		Pampierstad	NED000264
		Patsima	NED000265
		Sakhile	NED000266
		Shanty	NED000267
		Magogong	NED000269
		Mountain View	NED000270
Renosterberg Local Municipality	NC075	Greenpoint	NED000337
		Thembinkosi	NED000339
		Uitsig	NED000340
		Lukhanyisweni	NED000341
		Phillipvale	NED000343
Richtersveld Local Municipality	NC061	Sizamile	NED000811
		Sanddrift	NED000813
		Eksteenfontein	NED000815
		Kuboes	NED000816
		Lekkersing	NED000817
Siyancuma Local Municipality	NC078	Campbell	NED000297
		Voelfontein	NED000298
		Bongani	NED000299
		Matlhomola	NED000305
		Rainbowvalley	NED000306
		Broadwaters	NED000311
		Plooysburg	NED000312
Siyathemba Local Municipality	NC077	Marydale	NED000313
		Rainbow	NED000314
		Rame Road	NED000315
		Riemvasmaak	NED000316
		Zwelitsha	NED000317
		Blinkpunt	NED000318
		Niekerkshoop	NED000319

		Thabang	NED000320
		Bonteheuwel	NED000321
		Ethembeni	NED000322
		Ethembeni Ext	NED000323
		Ext 15	NED000324
		West End	NED000326
Sol Plaatje Local Municipality	NC091	Ikageng	NED000107
		Mandela Square	NED000108
		Motswedimosa	NED000109
		Rietvale	NED000110
		Ritchie	NED000111
		Modderrivier	NED000112
Thembelihle Local Municipality	NC076	7de Laan	NED000328
		Steynville	NED000330
		Thamboville	NED000331
		Deetlefsville	NED000334
Tsantsabane Local Municipality	NC085	Boichoko	NED000682
		Newtown	NED000683
		Postdene	NED000684
		Postdene Ext	NED000685
		Riemvasmaak	NED000687
		Groenwater (Metsimata	NED000690
		Groenwater Station	NED000691
		Jenhaven	NED000692
		Maditshabe	NED000694
		Maremane	NED000695
		Maseutlwadi	NED000696
		Skeyfontein	NED000697
Ubuntu Local Municipality	NC071	Loxton West	NED000366
		Sabelo	NED000370
		Grens	NED000374
		Missionvale	NED000377
		Sunrise	NED000379
Umsobomvu Local Municipality	NC072	Kuyasa	NED000180
		Masizakhe	NED000189
		Norvalspont	NED000188
		Eurekaville	NED000186
		Kwazamuxolo	NED000187

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA GAUTENG DIVISION, PRETORIA
Private Bag X67, Pretoria 0001
REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA GAUTENG DIVISION, PRETORIA

Signed at Pretoria on this 8TH day of MAY 2017.

Chris Forlee
CHIEF EXECUTIVE OFFICER

22/12/2022-11:31:00 AM

X17 0190

Distribution System Operating Code

Version 6.2

(January 2022)

This document is approved by the National Energy Regulator of South Africa (NERSA)

Administered by:

RSA Grid Code Secretariat
Contact: Mr. Target Mchunu
Eskom Transmission Division, System Operator
P.O Box 103, Germiston 1400
Tell: +27 (0)11 871 3076
Email: mchunut@eskom.co.za

ZA

Table of Contents

1. Objective

(1) To set out the responsibilities and roles of the *participants* as far as the operation of the *Distribution System* is concerned and more specifically issues related to:

(a) economic operation, *reliability* and security of the *Distribution System*

(b) operational authority, communication and contingency planning of the *Distribution System*

(c) management of power quality

(d) operation of the *Distribution System* under normal and abnormal conditions

(e) field operation, maintenance and maintenance coordination/ outage planning

(f) safety of personnel and public

2. Scope of Application

(1) The *Distribution System Operating Code* shall apply to all *Users* of the *Distribution System* including:

(a) *Distributors*

(b) *Embedded Generators*

(c) *Generators*

(d) *End-use customers*

(e) *Traders / Retailers*

(f) *Resellers*

(g) Any other entities with equipment connected to the *Distribution System* (for example *transmission national service providers (TNSPs))*

(h) *System Operator (SO)*

3. Operational Responsibilities of *Distributors*

(1) The *Distributor* shall operate the *Distribution System* to achieve the highest degree of reliability and shall promptly take appropriate remedial action to relieve any condition that may jeopardise reliability.

(2) The *Distributor* shall co-ordinate voltage control, demand control, operating on the *Distribution System* and security monitoring in order to ensure safe, reliable, and economic operation of the *Distribution System.*

(3) In the event of an *embedded generator* having to shutdown or *island* plant because of a disturbance on the *Distribution network*, the *Distributor* shall carry out network restoration to minimise the time required to resynchronise the shed embedded generating *units.*

(4) Ensuring that the availability and reliability of every power station supply is maximised at all times under normal and abnormal conditions

(5) The *Distributor* may shed *customer* load to maintain system integrity. Following such action, *customer* load shall be restored as soon as possible after restoring and maintaining system integrity.

(6) The *Distributor* shall operate the *Distribution System* as far as practical so that instability, uncontrolled separation or cascading outages do not occur.

(7) The *Distributor* is responsible for efficient restoration of the *Distribution System* after *supply interruptions.* The restoration plans shall be prioritised in accordance with customer requirements and as described in *NRS 047.*

(8) The *Distributor* shall ensure it has sufficient *resources* to continuously monitor and operate the *Distribution System*.

(9) The *Distributor* shall establish and implement operating instructions, procedures, standards and guidelines to cover the operation of the *Distribution System* under normal and abnormal system conditions.

(10) The *Distributor* shall operate the *Distribution System* within defined technical standards and equipment operational ratings.

(11) The *Distributor* shall ensure adequate and reliable communications to all major users of the *Distribution System*. Communication with all *customers* shall be provided in terms of *NERSA* license requirement.

4. Operational Responsibilities of *Embedded Generators* and Other *Customers*

(1) When conditions on the *Distribution System*, under normal or abnormal conditions, become such that it may jeopardise plant or personnel of *customers, customers* shall immediately disconnect from the *Distribution System*.

(2) The *Embedded Generator* shall ensure that its *generating units* are operated within the capabilities defined in the *Connection Agreement* entered into with the *Distributor.*

(3) The *Embedded Generator* shall reasonably cooperate with the *Distributor* in executing all the operational activities during an emergency generation condition.

(4) *Customers* shall assist the *Distributors* in correcting *quality of supply* problems caused by the *Customer's* equipment connected to the *Distribution System*.

JA

(5) *Customers* shall at all times operate their equipment in such a manner to ensure that they comply with the conditions specified in their supply agreement.

(6) All customers must declare any generating plant except for Embedded Generators that may be paralleled with the Distribution network via switching, and specify the interlocking mechanism to prevent inadvertent parallel operation with the Distributor network.

(7) *Embedded generators* shall have the required protection to trip in the event of a momentary supply loss causing an island condition to prevent paralleling out of synchronism due to auto-reclose functionality on the *Distributor's* network.

5. Operational Authority

(1) The *Distributor* shall have the authority to instruct operating on the *Distribution System*. Operational authority for other networks shall lie with the respective asset owners.

(2) Network control, as it affects the interface between the *Distributor* and a *customer*, shall be in accordance with the *operating agreements* between the *participants*.

(3) Except where otherwise stated in this code, no *participant* shall be permitted to operate the equipment of another without the permission of such other *participant*. In such an event the asset owner shall have the right to test and authorise the relevant operating staff in accordance with its own standards before such permission is granted.

(4) Notwithstanding the provisions of section 3 of this code, *participants* shall retain the right to safeguard their own equipment.

6. Operating Procedures

(1) The *Distributor* shall develop and maintain operating procedures for the safe operating of the *Distribution System*, and for assets connected to the *Distribution System*. These operating procedures shall be adhered to by *participants* when operating equipment on the *Distribution System* or connected to the *Distribution System*.

(2) Each *customer* shall be responsible for his own safety rules and procedures at least in compliance with the relevant safety legislation. *Customers* shall ensure that these rules and procedures are compatible with the *Distributor* developed procedures defined in paragraph 6 (1) above.

(3) *Customers* and service providers shall enter into operating agreements where not included in the supply agreement, as defined in the *service provider* licenses.

TA

7. Operational Liaison

(1) The *Distributor* shall be responsible for ensuring adequate operational liaison with connected *participants*.

(2) The *participants* shall appoint competent personnel to operate their network and where needed shall establish direct communication channels amongst themselves to ensure the flow of operational information between the *participants*.

(3) If any *participant* experiences an emergency, the *Distributor* may call upon other *participants* to assist to an extent as may be necessary to ensure that such emergency does not jeopardise the integrity of the *Distribution System*.

(4) Pursuant to 7(3) above, the relevant *participant* shall ensure that the emergency notification contain sufficient details in describing the event including the cause, timing and recording of the event to assist the *Distributor* in assessing the risk and implications to the *Distribution System* and all the affected *Customers'* equipment.

(5) For planned events, which have an identified operational effect on the Distribution System, or on *Customers'* equipment connected to the *Distribution System*, the relevant *participant* shall notify the *Distributor*.

(6) Where it is possible for a *customer* to *parallel supply points* or transfer load or *embedded generation* from one *point of supply* to another by performing switching operations on the *customer's* network, the *operating agreement* shall cover at least the operational communication, notice period requirements and switching procedures for such operations.

(7) The *Distributor* and *customers* shall agree on the busbar configuration(s) at each point of supply during normal and emergency conditions. The *Distributor* and *customers* shall agree on the busbar configuration(s) at each *point of supply* during normal and emergency conditions. The *Distributor* shall keep updated records of such agreements.

8. Emergency and Contingency Planning

(1) The *Distributor* shall develop and maintain emergency and contingency plans to manage the system contingencies and emergencies that affect the delivery of the *Distribution System* and the Interconnected Power System. Such plans shall be developed in consultation with all affected *participants*, and shall be consistent with internationally acceptable practices, and shall include but not be limited to:

   (a) under-frequency load shedding

   (b) Prevention of voltage slide and collapse

(c) meeting any national disaster management requirements including the necessary minimum load requirements

(d) forced outages at any point of connection

(e) restoration and continuation of supply to every power station during normal and abnormal conditions is to be classified as a high priority

(f) supply restoration.

(2) Emergency plans shall enable the safe and orderly recovery from a partial or complete system collapse, with minimum impact on *customers*.

(3) All contingency and emergency plans shall be reviewed biennially or in accordance with changes in network conditions.

(4) All contingency and emergency plans shall be verified by audits, if possible by using onsite inspections and actual tests. In the event of such tests causing undue risk or undue cost to a participant, the *Distributor* shall take such risks or costs into consideration when deciding whether to conduct the tests. Any tests shall be carried out at a time that is least disruptive to the *participants*. The costs of these tests shall be borne by the respective asset owners. The *Distributor* shall ensure the co-ordination of the tests in consultation with all affected *participants*.

(5) The *Distributor* shall, in consultation with the *NTC* and *SO*, set the requirements and implement:

(a) Automatic and manual under frequency load shedding in accordance with the *System Operator's* requirements.

(b) Automatic and manual under voltage load shedding to prevent voltage collapse.

(c) Manual load shedding to maintain network integrity.

(6) *Participants* shall make available loads and schemes to comply with these requirements.

(7) The *Distributor* shall be responsible for determining emergency operational limits on the *Distribution System*, updating these periodically and making these available to the *participants*.

(8) The *Distributor* shall conduct network studies which may include but not be limited to load flow, fault *level*, stability and resonance studies to determine the effect that various component failures would have on the reliability of the *Distribution System*.

9. Operation during *Abnormal Conditions*

FA

(1) During *abnormal operating conditions* the *Distributor* shall be obliged to take necessary precautionary measures to prevent network disturbances from spreading and to restore supply to *consumers*.

(2) The *Distributor* shall cooperate with the *SO* and *TNSP* in taking corrective measures in the event of abnormal conditions on the *Distribution System*. The corrective measures shall include both supply-side and demand-side options. Where possible, warnings shall be issued by the *Distributor* to affected *participants* on expected utilisation of any contingency resources.

(3) The *Distributor* shall be entitled to disrupt some sections of the network in the event of a prolonged disturbance resulting from unsuccessful corrective measures undertaken.

(4) Termination of the use of emergency resources shall occur as the order of return being determined by the most critical loads, first in terms of safety and then plant.

(5) During emergencies that require load shedding, the request to shed load shall be initiated in accordance with procedures prepared by the *Distributor*.

10. Independent Actions by Participants

(1) Each *participant* shall have the right to reduce supply or demand, or disconnect a *point of connection* under emergency conditions, if such action is necessary for the protection of life or equipment and shall give advance notice of such action where possible.

11. Demand and Voltage Control

(1) The *Distributor* shall implement demand control measures when:
- (a) Instructed to by the *SO*
- (b) Abnormal conditions exist on the *Distribution System*,
- (c) Multiple outage contingency exists resulting in *island* grid operation
- (d) Any other operational event the *Distributor* deems to warrant the implementation of demand control measures for the safe operation of the *Distribution System*.

(2) Demand control shall include but not limited to:
- *(a)* *Customer* demand management
- (b) Automatic under-frequency load shedding
- (c) Automatic under-voltage load shedding
- (d) Emergency manual load shedding
- (e) Voluntary load curtailment

(3) The *Distributor* shall develop load reduction procedures, which shall be regularly updated, to reduce load in a controlled manner taking cognisance of the type of load.

(4) *The Distributor* shall endeavour to maintain system voltage to be within statutory limits at the *points of supply* or otherwise as agreed in the operating / supply agreement.

12. Fault Reporting and Analysis/Incident Investigation

(1) The *end-use customers* and *Embedded Generators* shall report the loss of major loads or *generation* (as agreed by the *participants*) to the *Distributor* within 15 minutes of the event occurring. Notice of the intention to reconnect such shall be given with at least 15 minutes advance notice to enable the *Distributor* to take any necessary action required.

(2) The *Distributor* shall investigate all incidents that materially affected the quality of supply to another *participant*. The *Distributor* shall initiate and co-ordinate such an investigation and make available the findings of such investigation to affected *participants* on request.

(3) The findings of such an investigation shall include where relevant:

- (a) Date and time of the incident
- (b) Location of the incident
- (c) Duration of the incident
- (d) Equipment involved
- (e) Cause of the incident in compliance with *NRS048*.
- (f) Demand control measures undertaken specifically recording the customer MWs shed and energy lost as a result of the measures taken.
- (g) Supply restoration details.
- (h) *Embedded Generation* interrupted
- (i) Under-frequency Load Shedding response
- (j) Estimated date and time of return to normal service
- (k) *Customer* load tripped MW and energy lost when incident occurred or as a direct result of incident not including any Demand Control Measures taken
- (l) Estimate number of *customers* having lost supply.
- (m) Recommendations

(4) Any *participant* shall have a right to request an independent audit of the findings, at its own cost. If these audit findings disagree with the original findings, the *participant* may follow the dispute resolution mechanism as specified in the *Governance Code*.

13. Distributor Maintenance Program

(1) Each *Distributor* shall have a maintenance philosophy against which their maintenance practices and programs are compiled and documented in accordance with *NRS082*. These documented maintenance programs must be auditable.

(2) The *Distributor* shall compile at least an annual maintenance plan in line with the budget period.

(3) Accurate records of maintenance done shall be kept for a period of at least 5 years.

(4) Scheduling of planned outages should coincide with the maintenance requirements of other *participants* connected to the affected network.

(5) All participants that may be affected by the planned outages will be informed at least 2 days or 48 hours in advance.

14. Testing and Monitoring

(1) A *participant* has the right to request to test and / or monitor any equipment at the *point of connection* to the *Distribution System* to ensure that the *participants* are not operating outside the technical parameters specified in any part of the *Distribution Grid Code* and other applicable standards which the *participants* are required to comply with. Such testing and / or monitoring shall be carried out as mutually agreed by the *parties*.

(2) A *participant* found to be operating outside the technical parameters shall, within such time agreed upon by the parties involved, remedy the situation or disconnect from its network the equipment causing problems.

(3) Any dispute arising out of the test and monitoring process shall be resolved through the *dispute resolution* mechanism in the *Governance Code*.

15. Safety Co-ordination

(1) The *Distributor* shall comply with relevant legislation and develop Operating Regulations to ensure safety of personnel whilst operating on the *Distribution System* or any equipment connected to the *Distribution System*.

(2) Where operational boundaries exist, there shall be a joint agreement on operating procedures to be complied with by all affected *participants*.

(3) There shall be written authorisation of personnel who operate on or work on live equipment forming part of or connected to the *Distribution System*.

(4) The "Operating Regulations" referred to in section 15 (1) of this code shall include rules and regulations for the safe operating of plant, continuity of supply and authorisation of personnel related to the operating of *HV*, *MV* and *LV* equipment.

16. Disconnection and Reconnection

(1) The *Distributor* may disconnect supply to the *customer's* supply address if the *customer* fails to comply with the written notice of non-compliance issued by the *Distributor* or any arrangement entered into by the *Distributor* and the *customer* which the *customer* has failed to comply with including non-compliance with the *Distributor* applicable standards.

(2) The *Distributor* shall have the right to interrupt or disconnect supply if a threat of injury or material damage is anticipated as a result of the malfunctioning of the electrical installation equipment on the *Customer's* premises or on the *Distribution System*.

(3) The *Distributor* may disconnect immediately without notice the supply to the *customer's* supply address if:

(a) The supply of electricity to a *customer* is used anywhere else other than at the *customer's* premises as specified in the *connection agreement*.

(b) A *customer* takes at the *customer's* supply address electricity supplied to another *customer*.

(c) A *customer* is tampering with or permits tampering with the meter and associated components.

(d) A *customer* allows electricity supply to bypass the meter without the *Distributor's* consent.

(4) *Customer* (connected at *MV* and *HV* levels) shall give written notice to the *Distributors* of any intended voluntary disconnection.

(5) The *Distributor* shall reconnect supply to the *customer* on request by the customer or retailer on behalf of the *customer* subject to compliance with the relevant provisions of the *Distribution Code* and other *Distributor* applicable standards including the timing of reconnection and any reconnection charge imposed by the *Distributor*.

17. Commissioning and connection

(1) *MV* and *HV customers* shall supply commissioning programmes to the *Distributor* control and operating facility at least 1 month in advance. Subsequently, a notice of first connection shall be given to the *Distributor* control and operating facility at least 2 weeks before actual

connection. Details of the information required shall include but not be limited to the following:

(a) Commissioning procedures and programmes

(b) Documents and drawings required

(c) Proof of compliance with standards

(d) Documentary proof of the completion of all required tests

(e) SCADA information, to be available and tested before commissioning

(f) Site responsibilities and authorities.

(2) When commissioning equipment at the point of connection, the *Distributor* shall liaise with the affected participants on all aspects that could potentially affect their operation.

(3) The *Distributor* and *customers* shall perform all commissioning tests required in order to confirm that the *Distributor's* and the *customers'* plant and equipment meet all the requirements of the *Distribution Code* before being connected to and energised from the *Distribution* system.

18. Outage scheduling and co-ordination

18.1 Responsibilities of the *Distributor*

(1) *Distributors* shall, with reference to the relevant network *Service Providers* outage plans and relevant *Generators* outage programs, compile the daily outage schedule which shall:

(a) endeavour to cater for the planned maintenance and commissioning of new equipment

(b) describe the planned outage

(c) identifies the risks and impact on network performance in accordance with NRS 047

(d) describe the practical contingency plans devised to counter risks, and

(e) define the roles and responsibilities of the personnel designated to manage and minimise the impact of these outages on the *Distribution System* and its users.

(2) Not withstanding clause 18.1 (1) above, the *Distributor* shall co-ordinate relevant outages with the *SO*.

(3) In addition to paragraph 18.1 (1) above, the *Distributor* may require information from the *Customers* regarding major plant and associated equipment which may affect the performance of the *Distribution System* and may require additional resources to be committed during the outage planning process.

(4) *Customers* with co-generation and *Embedded Generators* with the maximum capacity greater than 1MW shall furnish to the *Distributor* information on *planned outages* in order for the *Distributor* to properly plan, and coordinate its control, maintenance and operation activities.

(5) The *Distribution* outage schedule shall be submitted to the *NER*SA upon request.

18.2 Risk-related Outages

(1) All risk-related outages shall be scheduled with an executable contingency plan in place. The compilation of the contingency plan is the responsibility of the relevant *Distributor*.

(2) Contingency plans shall address:

(a) Safety of personnel

(b) Security and rating of equipment

(c) Continuity of supply

(3) The relevant control centres shall confirm that it is possible to execute the contingency plan successfully.

18.3 Communication of System Conditions, Operational Information and *Distribution System* Performance

(1) The *Distributor* shall be responsible for providing *participants* with operational information as may be agreed from time to time. This shall include information regarding *planned* and *forced outages* on the *Distributor*.

(2) The *Distributor* shall inform *participants* of any network condition that is likely to impact the short and long-term operation of that *participant*.

(3) The *Distributor* shall record operational information as specified in the *Information Exchange Code*. This information shall be made available to all *participants* on request.

18.4 Unplanned Interruptions or Outages

(1) In case of unplanned interruptions or *outages* the *Distributor* may require a *customer* to comply with reasonable and appropriate instructions from the *Distributors* and may further:

(a) Require the *customer* to provide the *Distributor* emergency access to *customer* owned distribution equipment normally operated by the *Distributor* or *Distributor* owned equipment on *customer's* property.

(b) Interrupt supply to the *customer* to effect repairs to the *Distribution System*.

(2) Subsequent to clause 18.4 (1), the *Distributor* shall make arrangements to keep customers informed about the expected duration and other details following unplanned interruptions.

18.5 Refusal/Cancellation of Outages

(1) No *participant* may unreasonably refuse an outage request. No *participant* may unreasonably postpone or cancel a previously accepted outage.

(2) The direct costs related to the cancellation/postponement of an outage shall be borne by the respective asset owners.

18.6 Planned Interruptions or Outages

(1) For planned interruptions or outages the *Distributor* shall act in accordance with *NRS047* and provide the affected *Customers* with information relating to the expected date of the outage, time and duration of the outage and shall established reasonable means of communication to the *Customers* for outage related enquiries.

19. Telecontrol

(1) Where Telecontrol facilities are shared between the *Distributor* and other *participants*, the *Distributor* shall ensure that operating procedures are established in consultation with the *participants*.

9
74

NRS 048-9:2019

Edition 2

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA

ELECTRICITY SUPPLY — QUALITY OF SUPPLY

PART 9: CODE OF PRACTICE – LOAD REDUCTION PRACTICES, SYSTEM RESTORATION PRACTICES AND CRITICAL LOAD AND ESSENTIAL LOAD REQUIREMENTS UNDER POWER SYSTEM EMERGENCIES

Foreword

Emergency load reduction is a measure implemented by the System Operator and distribution control rooms in order to prevent a national, regional or local blackout when system conditions are such that demand cannot be met by the available power system capacity, or when adequate reserves required to manage the power system security cannot be maintained without a reduction in load. Emergency load reduction in this context refers to mandatory measures required over-and-above contracted load reduction (demand response), energy conservation schemes, and demand side management measures as may be in place at the time.

NOTE The *power system* includes generation, transmission and distribution infrastructure.

Emergency load reduction may take the form of *load shedding* (time-based interruption of supply to customers on a rotational basis), *mandatory load curtailment* (self-reduction by customers in response to an instruction given by the system operator), *load limiting* (a limit placed on the current or power consumed by a customer, typically enabled by smart meter technology), or customer *load switching* (remote switching of customer circuits to specific appliances, typically enabled by smart meter technology or ripple control technology).

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA

Load shedding differs from a blackout in that load shedding is a controlled intervention affecting a limited number of customers at a time, whilst a blackout happens without warning in an uncontrolled manner and can affect many (if not all) customers simultaneously for an unpredictable period of time.

NOTE The media may at times refer to load shedding as "rolling blackouts". The term load shedding is an internationally accepted engineering terminology for controlled load reduction by interrupting supply to customers on a rotational basis.

Restoration of supply to all customers after a significant system incident or blackout could take days to weeks. Whilst the order in which supply is restored to individual customers is often dictated by the nature of the incident, the ability to restore supply to essential loads as quickly as possible should form part of the restoration regime. This requires that essential load requirements are provided by customers to power system operators.

This part of NRS 048 was developed to address the need for a *national code of practice* for real-time emergency load reduction and restoration of supply after a major system incident. The code addresses not only the power system requirement (the load reduction required) but how this is done and communicated so as to have the least negative impact on critical infrastructure. This need for such a code arose subsequent to national load shedding undertaken in South Africa in 2008. Requirements for extreme power system constraints and blackout restoration have also been included in the form of essential load requirements.

This second edition of the code replaces the first edition published in 2010. Several changes and enhancements have been included in this edition, based on:

a) experience in implementing the requirements of the first edition;

b) execution of emergency load reduction since November 2013 (when it was required for the first time since 2008);

c) feedback from licensees and customers;

d) engagement with NERSA and the Grid Code Advisory Committee on various clarifications regarding the application of the code; and

e) engagements with the Government War Room.

The changes and enhancements included in this second edition are:

a) revision of the forward and introduction to better address the *context* of load reduction and system restoration requirements;

b) the inclusion of emergency load reduction scenarios in the introduction of this document to facilitate a better understanding of the context when available options for emergency load reduction are selected;

c) clarification and expansion of the principles on which the code is based (in order to facilitate pragmatic decision-making by the System Operator to reduce the impact on customers and the economy). In particular, an increased pragmatism in application of the requirements of this document and a review of the concept of equitable participation;

d) clarification of the definition *of a system emergency* given the requirement of the system operator to ensure adequate reserves during a system emergency, and to prudently manage reserves over various operating periods;

e) clarification on the protocols for declaring a system emergency (inclusion of the definitions of a System Early Warning and System Alert condition);

f) clarification of the application of the code in relation to other legal requirements that the electricity supply industry is subject to;

g) clarification of the application of the code in managing a longer-term energy constraint through planned load reduction and rules of implementing this. This is in the absence of an approved energy conservation scheme (the first edition included an assumption that an energy conservation scheme would be in place to manage such constraints);

h) removal of reference to an energy conservation scheme, noting that, should it be implemented, the rules of such a program will dictate how it relates to this code of practice;

i) clarification on the pragmatic use of *load shedding* versus mandatory curtailment in the context of different system conditions;

j) revision of the load shedding schedules to cater for all time periods under all stages of load reduction (24 hrs per day including weekends);

k) greater standardisation of load shedding schedules for the electricity supply industry;

l) introduction of an additional stage of scheduled load shedding, i.e. Stages 1 to 4. (This is to: address the large increment in load reduction required previously under Stage 3; manage deeper levels of reduction whilst limiting the impact on the country; and allow for greater levels of planned reduction whilst still allowing for an additional stage of scheduled load shedding should system conditions dictate this);

m) differentiation of a 15 % notified curtailment requirement under Stage 3 vs. a 20 % notified curtailment requirement under Stage 4;

n) inclusion of a new section related to a severe supply constraint and the implementation of *contingency schedules* for controlled load reduction requirements beyond Stage 4. This is in terms of the Disaster Management Act, which requires coordinated planning for electricity-related scenarios even where these may have a low likelihood of materializing;

o) increased flexibility for curtailment customers through options that better match the economic impacts that these customers would be exposed to;

p) removal of Stage 0 as a curtailment option given the low uptake of this option, the similar role that demand market participation plays, and in order to reduce the complexity of load shedding;

q) the specification of compliance and reporting requirements (general and real-time);

r) guidance on the implementation of smart metering as a technology platform for reducing the impact of load shedding on customers; and

s) extensive editorial changes to the document.

The second edition of this part of NRS 048 has been developed in the context of known system and technology limitations. These limitations include the embedded nature of some customers that may be severely impacted by load shedding in electricity networks as they are currently designed, as well as the limited penetration of smart metering technology in South Africa.

NOTE The implementation of smart metering offers the electricity supply industry with a significantly improved capability for emergency load reduction, both on an incentivized and mandatory basis. It also allows supply to be maintained to identified categories of customers during load shedding. This code supports the implementation of such technology.

Compliance with the requirements of this part of NRS 048 has been mandated by NERSA through inclusion of the first edition as a license condition to all licensees in the electricity supply industry. It is anticipated that NERSA will also mandate this edition, as modified during its consultation processes, as a license condition in terms of the Electricity Regulation Act. Alternatively, this code may be included as a requirement under the Grid Code. General compliance by licensees to the code will be overseen by NERSA in terms of its licensing processes.

It should be noted that NERSA may from time to time mandate alternative protocols or clarifications on the provisions related to the application of this code. Readers are advised to confirm any such changes with NERSA or their electricity supplier. It is anticipated that a formal structure will be identified or established by NERSA to review and make recommendations on clarifications and amendments required at short notice going forward, where implementation of this code such clarifications or amendments.

Whilst this code provides for an ordered and consistent approach to emergency load reduction, it does not subrogate any actions that the System Operator may deem necessary in real time to ensure the security of the national power system (in terms of its compliance to the Grid Code, amongst others to prevent a national blackout). This includes the requirement for the System Operator to prudently manage system operating reserves. In the context of an actual emergency, compliance with real-time load reduction requirements will be given effect to by the 'upstream' control centre (i.e. System Operator or control centre will instruct the level of load reduction required and take the necessary actions should this not be adequate).

Reference is made in this code to the Disaster Management Act, 2002 (Act No. 57 of 2002). In terms of the various requirements of the Act, this code supports disaster risk mitigation and response in relation to several identified electricity disaster risk scenarios, including: a national or regional blackout; a power system constraint at a national or regional level; and various scenarios that could give rise to a significant system constraint (including plant failure, natural phenomena, sabotage, and social and economic disruptions). In terms of the Disaster Management Act, the lead sector department responsible for national energy-related disasters is the Department of Energy. Each sector is responsible for the development of plans in the event of a significant supply constraint or blackout. The National Disaster Management Centre and the Provincial Disaster Management Centres are responsible for overseeing the coordination of these plans at a national and provincial level respectively.

Reference is made in the introduction to the potential legislation of essential load information to be provided by end-users of electricity. In South Africa this legislation might be the Occupational Health and Safety Act, 1993 (Act No. 85 of 1993), or the Mine Health and Safety Act, 1996 (Act No. 29 of 1996), or new legislation to cover energy and demand management.

The Board of Directors, Municipal Councils and management of electricity suppliers have fiduciary requirements in terms of the Public Finance Management Act, Municipal Finance Management Act

22/12/2022-11:31:00 AM

and/or the Companies Act that may have bearing on the conditions under which this code is invoked.

Reference is made in annex B, forms B.1 and B2, to legislated limits. In South Africa such limits, where relevant, are those covered by the following Acts (as amended):

a) The Constitution of the Republic of South Africa Act (Act No. 108 of 1996);
b) The National Environmental Management Act (Act. No. 107 of 1998);
c) The National Environmental Management: Air Quality Act (Act No. 39 of 2004);
d) The National Environmental Management: Waste Act (Act No. 59 of 2008);
e) The National Environmental Management: Biodiversity Act (Act No. 10 of 2004);
f) The National Water Act (Act No. 36 of 1998);
g) The Water Services Act (Act No. 108 of 1997); and
h) The National Heritage Resources Act (No. 25 of 1999); and the said Occupational Health and Safety Act.

This part of NRS 048 was compiled by a working group appointed by the NRS Association. The working group membership included a wide range of stakeholders, including representatives of the South African Electricity Supply Industry, NERSA, Government, and customer groupings (including formal representation of the Energy Intensive User Group (EIUG) and Business Unity South Africa (BUSA)). The working group at the time of publication of the second edition comprised the following members:

Koch R G (Chairman)	Eskom
Batohi V	eThekwini Municipality
Bhana D K	Eskom (Top Customer Services)
Chatterton B	Eskom (Distribution)
Cole T	SAB Miller
Correia A J	Eskom (Risk & Resilience)
de Beer G	Sasol
Delport S	City of Ekurhuleni Metropolitan Municipality
Gonya B	Eskom (Distribution)
Greyling A J	Anglo Gold Ashanti
Hull M	Eskom (Distribution)
Jacobs S	National Energy Regulator of South Africa (NERSA)
Jaeger F P	City of Cape Town
Kekana I	City of Tshwane Metropolitan Municipality
Kgalema L	City Power Johannesburg
Kneen M	Marcus Kneen (Pty) Ltd
Krumm D	South 32
Langridge I	Anglo American
Malaza V	National Energy Regulator of South Africa (NERSA)
Marais D	Umhlathuze Electricity
Miller M	Mondi Group
Mncube M	Department of Energy (DoE)
Moloto M B	City Power Johannesburg
Moloto P	City of Ekurhuleni Metropolitan Municipality
Morison I	Energy Intensive User Group (EIUG)
Ngidi L N	SALGA
Nundlal V (Project Leader)	Eskom (Technical Governance)
Peterson B	Eskom (Transmission Division)
Pittorino L	Eskom (Transmission Division)
Ramagaga M	City Power Johannesburg
Ratema D	National Energy Regulator of South Africa (NERSA)
Shabalala N	City Power Johannesburg
Smit T	Eskom (System Operator)
Thenga T	City of Ekurhuleni Metropolitan Municipality

NRS 048 consists of the following parts, under the general title *Electricity supply – Quality of supply:*

Part 2: Voltage characteristics, compatibility levels, limits and assessment methods.

Part 4: Application practices for licensees.

Part 6: Measurement and reporting of medium-voltage network interruption performance.

Part 7: Application practices for customers.

Part 8: Measurement and reporting of extra high voltage (EHV) and high voltage (HV) network interruption performance.

Part 9: National Code of Practice: Load reduction practices, system restoration practices, and critical load and essential load requirements under system emergencies.

Annexes B, C, and G form an integral part of this document. Annexes A, D, E, F and H are for information only.

Introduction

South Africa's electricity infrastructure is exposed to a variety of potential threats and vulnerabilities including: generation, transmission and distribution plant and control systems failures; extreme weather incidents and the impacts of climate change; wilful damage (including vandalism and sabotage) to electricity infrastructure; the impact of a sequence of unforeseen events and potential failure of barriers and protection systems and electricity constraints due to infrastructure capacity shortages and disruptions to critical resources (such as coal, gas, and liquid fuel) that may arise from time to time. Should the associated risks materialise, the resulting impact on safety, society, the environment and the economy can be significant.

The risk of a national blackout, whilst inherent to the operation of a large power system, has a low likelihood of materializing given operating protocols and protection systems in place. However, should a national blackout materialize the impact on the country would be severe – impacting critical sectors of society and the economy including personal and occupational safety, water supply and sewage systems, telecommunications and transport infrastructure, and even national security.

NOTE A blackout differs from load shedding/curtailment in that the former is considered a sudden, unexpected interruption in supply to a significant area of supply, whilst the latter is a controlled (manual or automatic) intervention to protect the total system from collapse in the event of a system emergency. Load shedding and curtailment measures are one of the measures implemented to protect the system from a blackout.

The risk of a severe national or regional electricity constraint may arise where infrastructure is damaged or inadequate to provide the system demand. The impact of such a constraint is dependent on the season, as the country's demand profile differs significantly in winter vs. summer. The winter demand profile is characterized by a high peak demand in the evening (3000 MW above the daily average) whilst the summer demand profile is more constant throughout the day. Typical winter and summer profiles are illustrated in Figure 1. With an increase in the penetration of grid-connected solar power in future, it can be anticipated that this profile may change.

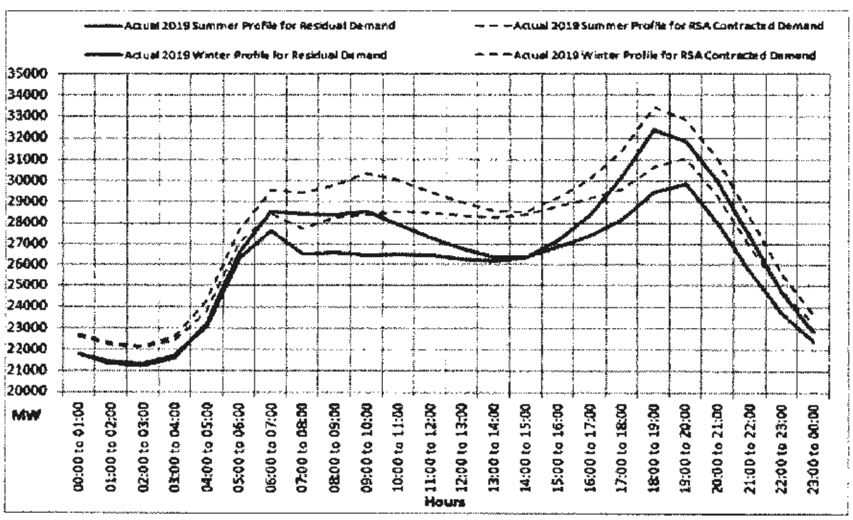


Figure 1 — Typical winter and summer demand profiles for the national power system (2019)

It is important to highlight that the need exists for a robust set of emergency load reduction protocols even under healthy system conditions, although the likelihood that emergency load reduction measures may be required when the power system is constrained for an extended period of time. A sequence of unexpected events or a large significant event in an otherwise healthy power system can give rise to the need for emergency load reduction. It should also be noted that emergency load reduction is not only required under generation capacity shortages, but could also arise due to regional or local transmission or distribution network constraints.

NOTE The 2003 blackout in Northeast USA and Ontario (Canada) that affected 50 million people was caused by transmission network constraints. The event could have been avoided by load shedding in the two hours of the emerging system emergency before the final cascading loss of multiple transmission lines and generators occurred (this last sequence of events took three minutes).

Whilst emergency load reduction is in principle implemented as a last resort (after contractual and voluntary arrangements for customer load reduction have been exhausted), it is important to note that prudent system operation requires adequate reserves to be maintained by the System Operator in order to ensure that anticipated contingencies can be catered for without the system being put at undue risk of a blackout (NOTE 1). The requirement to manage reserves applies also during a system emergency when load reduction is being implemented, as well as over extended operating periods where prudent operations requires that proactive measures to be deployed to manage available primary energy reserves (NOTE 2). In the absence of alternative load reduction protocols for managing longer-term energy constraints, load reduction may be necessary on a planned basis in order to provide greater predictability to customers under certain system constraints (NOTE 3). In this case, a given stage of load shedding or curtailment may be instructed for multiple days and available reserves would be used to manage variations in system supply and demand, rather than instructing different stages of load shedding on an ad-hoc basis.

NOTE 1 Such contingencies include a sudden loss of generation or transmission lines supplying electricity to South Africa from neighbouring countries.

NOTE 2 Under highly constrained system conditions that extend beyond a day or two, water reserves for the purpose of generating electricity may need to be managed pro-actively by implementing emergency load reduction.

NOTE 3 This application of emergency load reduction has been included in the second edition. The first edition was published under the assumption that an Energy Conservation Scheme would be approved.

Scenarios under which emergency load reduction may be required are identified in Figure 2. Indicative load reduction requirements are provided in Table 1 for winter and summer.

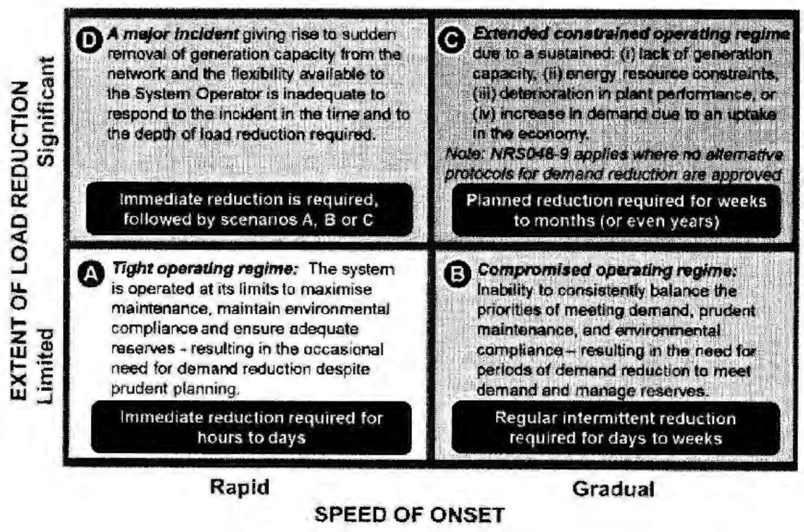


Figure 2 — Scenarios under which mandatory load reduction may be required showing the notice period and the depth/duration of load reduction

Table 1 — Indicative mandatory load reduction magnitude and duration requirements and operating regimes for the identified scenarios in winter and summer

1	2	3	4
Scenario	**Name**	**Winter reduction required (indicative only)**	**Summer reduction required (indicative only)**
A	Tight operating regime	A few nights per week twice a month. Immediate reduction of 1000-2000 MW for 4 hrs.: 17h00-21h00 typically 15 min - 4hrs notice [a,f]	A few days per week twice a month Immediate reduction of 1000-2000MW for 2-16hrs: 06h00-22h00 typically 15 min – 4 hrs. notice, generally towards the end of the week [b]
B	Compromised operating regime	A few nights a week every week. Regular intermittent reduction of 1000-3000 MW for 4 hrs.: 17h00-21h00 typically 15 min – 24 hrs notice [a,c,f]	A few days a week every week. Regular intermittent reduction of 1000-3000 MW for 16 hrs.: 06h00-22h00 typically 15min – 24 hrs. notice [c] Possible weekend reduction to manage system reserves for the week ahead.
C	Extended constrained operating regime	Planned / anticipated reduction up to 7 days per week every week. Reduction of 2000-4000 MW for 4 hrs: 17h00-21h00, where possible notified 48 hrs to 2 weeks in advance [d]	Planned / anticipated reduction up to 7 days per week every week. Reduction of 2000-4000 MW for 16hrs: 06h00-22h00, where possible notified 48 hrs to 2 weeks in advance [d]
D	Major incident	Immediate reduction of 1000-3000 MW (Followed by scenarios A,B, or C [e])	Immediate reduction of 1000-3000 MW (Followed by scenarios A,B, or C [e])

[a] In order to only call on load reduction if it is necessary, the System Operator may call a System Alert to prepare all control rooms for load shedding but not implement this if the actual peak demand is lower than anticipated. In these cases, mandatory curtailment may not be called on given the 2hr notice required.

[b] Where the required reduction is anticipated to be more than 2-4 hrs, both load shedding and curtailment could be called on. Alternatively, a similar approach may be taken to (a).

[c] Day-ahead notice is likely to be given when the system is under severe pressure and/or reserves need to be built up (for example over the weekend when load reduction can be limited as much as possible).

[d] Whilst the stage of load shedding may be notified well in advance, it is possible that higher stages may be required at times to manage increased constraints due to incidents on the system.

[e] Depending on the nature of the incident, which could range from temporary loss of supply from neighbouring countries due to a line fault, to loss of multiple units at one power station for an extended period of time.

[f] The availability of contracted interruptible load will determine how many evening peaks of the week need to be managed by calling on load shedding.

In terms of international good practice and in compliance to the Disaster Management Act and the Electricity Regulation Act (and associated Grid Code), the System Operator is required to undertake adequate contingency planning for various system contingencies. This part of NRS 048 supports planning for a system constraint and a blackout related to a variety of contingencies (including plant failure, natural phenomena, sabotage, and social and economic disruptions).

The measures implemented under emergency load reduction have a potentially significant impact on the country. This part of NRS 048 therefore requires a system emergency to be formally declared at an operational level by the system operator to ensure that all parties are clear on when the protocols are activated and when they are terminated. Such a declaration may be made immediately when the system is entering a state of collapse, pre-emptively when the system is approaching a state of collapse (i.e. all resources available to the system operator have been exhausted and the need for mandatory load reduction is imminent in the next few hours), or in cases where measure need to be taken to prudently manage system reserves over a given period (e.g. the next week). The duration of the emergency may last from a few hours to multiple weeks or even months.

The application of this part of NRS 048 should be seen in the context of other long-, medium- and short-term measures required to manage a potential imbalance in supply and demand. Prior measures to prevent such an emergency condition could include voluntary load reduction by customers in response to a system constraint, pricing mechanisms that encourage load reduction on constrained days (critical peak day pricing), implementation of an energy conservation scheme, and shorter-term interventions such as the use of interruptible load that has been contracted for - either under a supply agreement or through market mechanisms (see Figure 3). Other longer-term measures include: adequate investment in generation and supply network capacity; interventions to maximize generation and supply network availability (NOTE); and energy efficiency programmes. This part of NRS 048 applies after measures such as these above have failed to prevent the integrated power system or a localized part of the system from approaching or entering a state of collapse.

NOTE Prudent power system operation requires adequate maintenance to be undertaken to manage long-term plant availability and ensure the safety of plant and personnel. In the short term however, such interventions generally increase the risk of an emergency, should the system already be constrained and unexpected conditions arise during this maintenance period.

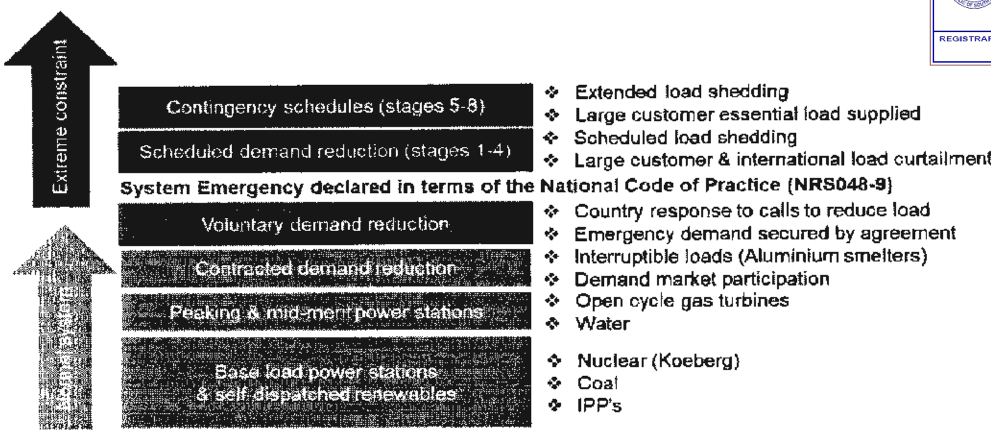


Figure 3 — Typical merit order showing the point at which this code is invoked. The implementation of scheduled demand reduction (Stages 1-4) and contingency demand reduction (stages 5-8) is shown

Manual, mandatory load reduction is an essential operating requirement under certain system conditions. Such reduction is a controlled intervention that takes into consideration issues such as equity, impact on customers, and information related to how and when customers are impacted. This needs to be proactively and prudently applied by the System Operator. Should this not be done timeously, or there is no time to implement load shedding and load curtailment, the System Operator will open breakers to interrupt supply to large supply areas (see Figure 4).

The final system defense against a national blackout is the under-frequency protection scheme which responds in under a second to a drop in frequency. Once this scheme is activated, supply and demand on the system needs to be brought back into balance by either bringing on line available reserves or by implementing emergency load reduction.

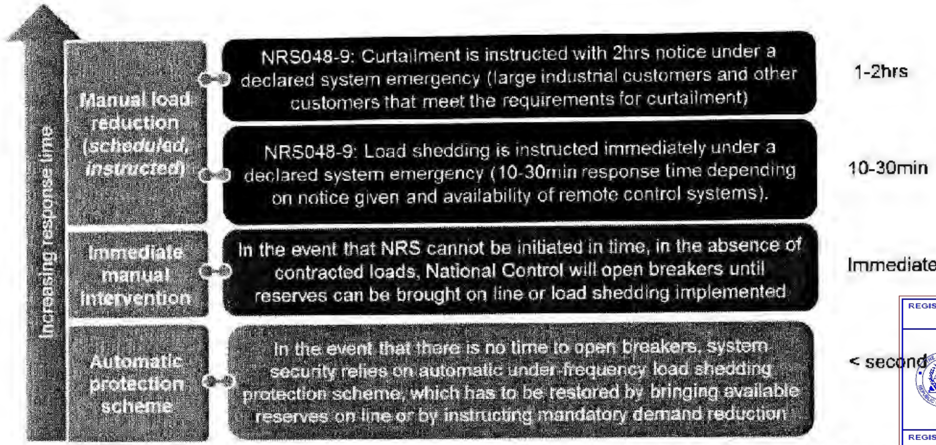


Figure 4 — Manual emergency load reduction (as applied in terms of this part of NRS 048-9) in relation to immediate manual interventions applied in the control room and automatic load reduction implemented through technology

Whilst laying down a national basis for the consistent application of load reduction and restoration practices by licensees (of NERSA), this part of NRS 048 also addresses:

a) options available to customers to minimize the impact of load shedding (e.g. alternatives to load shedding such as load curtailment);

b) the responsibilities of a variety of stakeholders (such as individual customers and local government) in relation to providing essential load information and protecting critical installations from the impact of load shedding; and

c) measures that need to be taken within individual customer installations in the event of supply interruptions or load shedding and curtailment.

The development of mandatory load reduction requirements requires several factors to be taken into consideration. These factors sometimes present conflicting requirements, and need therefore to be balanced on a pragmatic basis. The factors considered in developing this part of NRS 048 are:

a) the safety of people, the environment, and potential damage to plant associated with a critical national product;

b) predictability of when and for how long a customer will be interrupted or required to reduce demand;

c) equitable participation by customers, and how load reduction requirements are allocated between various regions across the country, metros, municipalities, large industrial customers, and international customers (see NOTES 1 and 2);

d) the social impact of load shedding and curtailment;

e) economic impact on the country;

f) technical constraints on executing load shedding and curtailment or restoration; and

g) the magnitude of the load reduction required and the speed at which this can be achieved.

NOTE 1 *Equitable participation* refers to a *striving for general fairness* in the manner in which customers are required to participate in load reduction schemes. It is recognized that *equal participation*, on the other hand, is not always possible given the nature of load shedding, system characteristics, and real-time-operational constraints.

NOTE 2 *Equitable participation* is a requirement that arises from the Electricity Regulation Act. This document therefore requires customers supplied by different licensees to be treated similarly.

This part of NRS 048 adopts a comprehensive approach to addressing various types of loads by specifying a range of interventions to make the country more resilient in the event of a system emergency. An approach that only considers supply network interventions to minimize the impact of mandatory load reduction (i.e. exclusion of such loads from load shedding schedules) is currently impractical, given the inflexible nature of existing network structures. This is largely because exclusion of some loads from load shedding schedules (and by implication other loads on the same electricity supply circuit) will increase the frequency at which other customers on the networks need to be shed. Similarly, a customer who would prefer to curtail load rather than be shed, cannot always be accommodated if other customers on the same circuit need to be shed.

Ideally the approach to addressing critical loads during emergency load reduction or restoration should be consistent from a national perspective (i.e. applied similarly by the various supply authorities). For this reason, this part of NRS 048 identifies a minimum set of critical load types that should be addressed by the various supply euthorities. Given current system limitations, this part of NRS 048 considers various alternatives for treating critical loads, i.e.:

a) the manner in which emergency load reduction is applied (i.e. time-based shedding versus a reduction of load for the duration of the emergency);

b) the specific time of day that different types of load are shed;

c) the exclusion of some specific loads from load shedding schedules;

d) protocols for interaction between the customers' operating critical loads and the electricity supply utility;

e) interventions in customer installations (e.g. the need for appropriate backup supplies); and

f) load curtailment options available to customers who comply with specific criteria.

In the case where critical loads exist within a customer installation, this information should be provided to a supply authority (termed an "essential load requirement" in this part of NRS 048). This information is particularly vital for a supply authority to establish priorities for power system restoration after a blackout. However, provision of this information to the supply authority is not intended to relieve the responsibility of the customer to ensure that adequate back up supply is available. The format for submitting such information is also provided in Annex E of NRS 048.

NOTE It is anticipated that the provision of essential load information will at some stage be legislated (see foreword).

Several technology innovations that are currently under development have the potential to significantly enhance the manner in which emergency load reduction can be undertaken (i.e. smart metering and load limiting technologies). In particular, these technologies have the potential to significantly reduce present system limitations related to the protection from load shedding of specific loads (or embedded generators) on a given network. The aim of this part of NRS 048 is to provide a code of practice for load reduction under the current limitations, whilst preparing for the potential implementation of such technology solutions.

The introduction of embedded generation provides a challenge to the development of load shedding schedules, as demand reduction required from a specific feeder may be accompanied by disconnection of the embedded generator. Whilst feeders where such generation provides a net export to the grid may be removed from the schedules, feeders with a net demand are best managed through smart meter interventions rather than load shedding.

NOTE It is estimated that the implementation of smart metering and load limiting relays on residential networks has the potential to achieve a load reduction of over 5 000 MW at system peak, when implemented by all distribution licensees in South Africa.

It is recognized that this part of NRS 048 is expected to evolve with time to take into account experience with the application of the requirements specified, as well as technology advances as discussed above.

Keywords

mandatory load reduction, load shedding, load curtailment, load limiting, load switching, critical loads, essential load requirements, load restoration, load shedding schedules, system emergency, smart metering.

22/12/2022-11:31:00 AM

0219

Contents

ELECTRICITY SUPPLY — QUALITY OF SUPPLY

Part 9: Code of Practice - Load reduction practices, system restoration practices and critical load and essential load requirements under power system emergencies

1. Scope

1.1 This part of NRS 048 is intended to provide for the implementation of a nationally consistent response to a variety of system emergencies. As such, this part of NRS 048:

a) provides electricity suppliers (licensees) with a standard methodology for developing emergency load reduction (shedding, curtailment, load limiting, and load switching) practices,

b) provides electricity suppliers (licensees) with best practice for prioritizing load restoration after a local, regional or national blackout,

c) defines and categorizes critical loads and essential load requirements,

d) provides electricity suppliers (licensees), customers, and national and local government with best practice on how to address critical and essential loads in the context of emergency load reduction or system restoration,

e) identifies the responsibilities that all stakeholders have in relation to sharing information on critical and essential loads,

f) identifies the responsibilities that the licensee utility has in terms of information sharing related to load shedding schedules and system status,

g) provides standard definitions related to emergency load reduction principles in order to facilitate common understanding between stakeholders,

h) defines the roles, responsibilities and limitations of licensees and customers in addressing various aspects of load shedding,

i) provides reporting formats to facilitate the collection of essential load data, and

j) specifies compliance and reporting requirements of licensees.

NOTE Examples are provided as annexes in order to facilitate understanding of the principles defined.

1.2 This part of NRS 048 is intended to be applied when all other measures (indicated in the introduction) are inadequate to prevent a demand-supply capacity constraint that could lead to risk of system collapse (at national or regional level).

NOTE It should be noted that NERSA may from time to time mandate alternative protocols or clarifications on the provisions related to the application of this code. Users of this code of practice are advised to confirm any such changes with NERSA or their electricity supplier.

1.3 This part of NRS 048 addresses manual load reduction. It is not intended to address the management of the automatic under-frequency load shedding scheme.

NOTE Annex A explains the relationship between manual load reduction as addressed by this part of NRS 048 and the automatic under-frequency load shedding scheme.

1.4 This part of NRS 048 applies to all licensees unless a deviation is approved by NERSA or an appropriately approved committee which can process exemption applications in a reasonable time, and where such deviations still provide the System Operator with the required load reduction for the relevant stage.

14

2. Normative references

The following documents contain provisions which, through reference in this text, constitute provisions of this part of NRS 048. All documents are subject to revision and, since any reference to a document is deemed to be a reference to the latest edition of that document, parties to agreements based on this part of NRS 048 are encouraged to take steps to ensure the use of the most recent editions of the documents listed below.

NRS 048-2, *Electricity supply – Quality of supply – Part 2: Voltage characteristics, compatibility levels, limits and assessment methods.*

NRS 048-6, *Electricity supply – Quality of supply – Part 6: Measurement and reporting of medium-voltage (MV) network interruption performance.*

NRS 048-8, *Electricity supply – Quality of supply – Part 8: Measurement and reporting of extra high voltage (EHV) and high voltage (HV) network interruption performance.*

3. Terms, definitions and abbreviations

For the purposes of this specification, the following terms, definitions and abbreviations apply.

3.1 Terms and definitions

base load [of the licensee]: total load at system peak less excluded loads [annual maximum simultaneous demand of all the licensee's supply points that feed the licensee]

NOTE The effect of any licensee-embedded generation operating at system peak is inherently included in the total load.

excluded load: all load which the licensee may not shed or curtail according to the provisions set out in this part of NRS 048 (See 4.4.1, 4.4.4 and 4.4.6.)

control centre: Eskom distribution control centre or municipal control centre dedicated to operate a defined area network

critical load: load that is managed to minimise the impact of load shedding or loss of supply in order to either maintain the operational integrity of the power system, or to avoid a cascading impact on public infrastructure

NOTE 1 Examples include coal mines that supply power stations, refineries, and fuel pipelines (in the latter case the line may be severely impacted if load shedding were applied at several stages of the line throughout the day).

NOTE 2 Protection measures include the exclusion from load shedding schedules, installing back-up facilities, or implementing specific protocols for interaction between the customer and the licensee.

customer: person or legal entity that has entered into an electricity supply agreement with a licensee

> **demand response; DR customer:** customer who has signed a contract with his supplier or Eskom to offer a portion of his load at a price, for the purpose of load reduction
>
> NOTE Depending on his participation parameters, such a customer may be categorized as an Instantaneous DR (IDR), Emergency DR (EDR) or a Supplemental DR (SDR) customer.

essential load requirement: minimum customer load requirement (e.g. MW, notification time, and duration) to avoid a direct and significant impact on the safety of people, the environment, and physical plant or equipment (or both) for nationally critical products, and which has been (a) specifically notified as such by the customer to the licensee, and (b) agreed to in writing by the licensee.

NOTE 1 The load required is generally part of the total load that a customer installation normally requires. A customer will be required to demonstrate the potential impact on safety, the environment, and physical equipment when notifying the licensee (see essential load requirements data format in annex B). The essential load requirement may be subject to verification by the licensee in terms of the requirements of this part of NRS 048.

NOTE 2 The load may be part of a larger installation that will still be required to participate in load shedding or curtailment schemes.

NOTE 3 This essential load requirement cannot be guaranteed to be served by a licensee.

NOTE 4 These loads should receive priority during restoration of the system (e.g. in the event of a major local interruption, or of a regional or national blackout).

NOTE 5 These loads were in the past categorized as SATEPSA loads under the (then) Republic of South Africa Telecommunications and Electrical Power Supply Authority (SATEPSA).

NOTE 6 Essential load requirements are typically less that 20 % of the customer installation's normal load.

feeder: point on the network where load is measured and interrupted for load shedding purposes

interruptible load: load where customers have signed long-term contracts with a licensee, whereby the licensee may interrupt a certain amount of load for a particular time period as a planned load intervention

NOTE These loads can specifically be used earlier in the merit order to reduce the possibility of a load reduction event.

interruption: phenomenon that occurs when one or more phases of a supply to a customer or group of customers are disconnected for a period exceeding 3 s
[NRS 047-1]

planned interruption: interruption that occurs when a component is deliberately taken out of service (by the licensee or its agent) at a selected time, usually for the purposes of construction, preventative maintenance or repair [NRS 047-1]

unplanned interruption: interruption that occurs when a component is taken out of service immediately, either automatically or as soon as switching operations can be performed, as a direct result of emergency conditions, or an interruption that is caused by improper operation of equipment or human error [NRS 047-1]

licensee: body, licensed by NERSA, that generates, transmits or distributes electricity

NOTE Such a body can be a direct licensee, or an agent (sub-distributor) of the licensee.

load curtailment: load reduction obtained from customers who are able to reduce demand on instruction

notified load curtailment: load that is curtailed within hours (typically with 2 h) of the instruction being issued

NOTE Instruction may be issued by the System Operator or its appointed agents.

load curtailment schedule: pre-defined load to be curtailed at pre-defined times during a load shedding event

load reduction: reduction in system load that can be achieved by load curtailment or load shedding (or both)

NOTE Load reduction might be required in order to

a) balance system demand in relation to the available generation capacity at the time; or

b) prevent overloading of transmission or distribution networks in the event of a network emergency (or both).

emergency load reduction: load reduction in response to an unplanned event or series of unplanned events on the system

NOTE Unplanned events could occur even when a healthy system reserve margin exists, and could be rotational should the event(s) last a few days

national load reduction: load reduction intervention required on a national level in response to national generation capacity shortages

planned load reduction: rotational load shedding or curtailment (or both) undertaken over an extended period of time to manage demand on the system

NOTE Planned load reduction might be the only option to secure the national system if power conservation measures are not effective. Whilst this part of NRS 048 could provide some guidance on elements of planned load shedding, it is intended to apply in the case of emergency load reduction only.

regional load reduction; local load reduction: load reduction intervention required to address regional or local power system capacity constraints

NOTE Although in some cases national schedules can be applied on a regional basis, the specific nature of the local event will determine what loads need to be reduced.

load switching: remote switching of appliances or circuits within a customer installation by a licensee

load limiting: reduction imposed by a licensee on the total load drawn by a customer at the supply point

load shedding: load reduction obtained by disconnecting load at selected points on the transmission or distribution system

automatic load shedding: load that is shed by automatic defence schemes in response to a sudden threat to the system **Example**: A sudden trip of several generation units that results in under frequency relays operating to reduce load.

manual load shedding: load that is removed by a human operator

NOTE Load shedding by its nature will affect all customers connected to the disconnected circuit.

rotational load reduction: regular shedding or curtailment (or both) required to manage demand over an extended period of time or for several load reduction events over a period of time, which spreads the requirement to reduce load over a wider customer base

load shedding schedule: schedule that pre-defines load to be shed at pre-defined times during a load shedding event

merit order: order in which generation or demand-side resources are applied by the System Operator as demand increases on the system

NOTE The merit order is determined largely by the relative cost of various reserves, as well as contractual provisions with participating customers.

normal load (in context of curtailment of customers' loads): average load measured reflective of typical demand

NOTE The purpose of calculating "a" value for normal demand is primarily for target setting and planning purposes for curtailment loads. Based on the length of the period chosen to calculate the average load, longer duration planned maintenance and plant breakdowns may be excluded. Some short term breakdowns may be considered as part of normal operations. Where customers reduce significant demand during night/early morning off peak periods, the average demand between 05h00 and 22h00 may be used to determine the normal load.

NOTE Defined for specific customers in determining the predetermined curtailment load. Annex H provides further clarity on how this is determined.

customer base load (CBL): is an average profile reflecting a typical normal daily operating demand profile

peak, off-peak (periods): periods at which system demand exceeds the normal demand throughout the day, periods at which system demand is significantly lower than the normal demand throughout the day

NOTE Peak periods vary and typically between 17h00 and 22h00 and match periods of higher demand and, off-peak periods between 22h00 and 06h00 the following day matching periods of lower demand.

point of supply: point at which the electrical installation of a **customer** (on any premises) is connected to the transmission or distribution system of the **licensee**

severe supply constraint: a system constraint that requires load reduction beyond that provided by the formal Stages 1-4 of load reduction as defined in this code of practice.

unavoidable loads: loads that would normally be sheddable, but that are excluded from the schedules because they are embedded in a network serving an excluded critical load

3.2 Abbreviations

BUSA: Business Unity South Africa
EIUG: Energy Intensive User Group
DR: Demand Response
KSACS: Eskom key customers
NERSA: National Energy Regulator of South Africa
SABS: South African Bureau of Standards
UFLS: Under-frequency load shedding
SO: System Operator

4. Application principles

4.1 Application by licensees

Licensees shall:

a) develop and maintain plans for mandatory load reduction in accordance with the practices laid out in this part of NRS 048;

b) execute these plans in accordance with the protocols laid out in this part of NRS 048; and

c) report and communicate on mandatory load reduction in accordance with the requirements of this part of NRS 048.

Where alternative load reduction practices are deployed, these shall:

a) achieve the equivalent load reduction requirements of the System Operator; and
b) be approved in writing by NERSA after consultation with the System Operator.

NOTE Such alternative practices might relate, for example, to the manner in which smart metering and load limiting technologies are applied as these become available and are implemented, or in the manner in which equity between customers are managed.

Where licensees choose not to operationally implement load reduction themselves:

a) such reduction shall be undertaken by the licensee supplying them; and

b) they shall remain accountable for all the engagements with their affected customers as laid out in this part of NRS 048 – including the communication of load shedding schedules and addressing the requirements of critical and essential loads.

Where municipal licensees are unable to demonstrate the ability to reduce demand by at least 80 % of the required amount within 15 min on advance notification (provided at least 1 hour before possible load shedding), and the ability to restore 80 % of this load in under 30 min:

a) Eskom shall shed the bulk supply points to these municipalities;
b) Eskom shall include these municipalities on its schedules going forward; and
c) the municipal licensees shall revise their schedules to reflect the relevant shedding times.

In all cases, the required amount of load to be shed shall comply with the requirements of the System Operator, whilst ensuring that the under-frequency system is not materially compromised.

4.2 Application by customers

Customers should take appropriate precautions or protective measures (or both) to prevent, or at least minimize, threat to life, or danger to the environment, or damage to equipment in the event of load shedding, an unplanned or planned interruption, or load restoration.

In particular, the requirements in this part of NRS 048 with regard to critical loads and essential requirements should be taken into consideration (NOTE 2).

NOTE 1 An unplanned interruption in supply could occur at any time due to local, regional or national network problems.

NOTE 2 Not all customers defined as critical loads are kept off the schedules.

4.3 Variations and exemptions

NERSA may from time to time issue variations or exemptions from this code of practice, where conditions require such variations or exemptions to be implemented outside of formal revisions of this code. Licensees may request such variations or exemptions from NERSA.

NOTE NERSA will consider such exemptions in light of the motivation provided, the requirements of the System Operator, and the principles outlined in section 4.4.

4.4 Principles

A co-ordinated approach to load reduction shall be developed by each licensee based on the principles articulated in 4.4.1 to 4.4.8.

4.4.1 Principle 1 – Protection of the automatic under-frequency scheme

The automatic under-frequency scheme is the last defense against a blackout of the national power system. For this reason:

a) where time permits, manual load reduction shall be implemented in order to maintain the balance between demand and supply, ensure adequate system reserves, and thereby minimize the need for the automatic under-frequency system to operate;

b) through appropriate design of the manual load reduction scheme, the integrity of the national automatic under-frequency load shedding system shall not be materially compromised when manual load reduction is undertaken;

c) where system conditions dictate, proactive load reduction may be required to prevent deeper levels of load shedding that could place the system at greater risk later in the week;

NOTE Although both automatic under-frequency load shedding and manual load shedding respond to a supply/demand imbalance, the conditions that these respond to and the consequences of their failure to respond are very different. Manual load shedding is a controlled, ordered and pro-active measure to manage a short-term capacity constraint on the system. Automatic under-frequency load shedding is an immediate, reactive response to a sudden unplanned loss of generation that might otherwise compromise the system integrity. The consequences of an inadequate response by the automatic under-frequency scheme can be catastrophic and widespread, which includes a complete loss of supply to the entire national power system.

4.4.2 Principle 2 – Equitable participation by all customer installations

Customers supplied by different licensees should to be treated similarly in terms of the requirements of this code of practice. All customer installations should be considered for mandatory load reduction under a system emergency, based on broadly equitable participation by customers. To this effect, all customers should by default be shed, and such shedding shall be in terms pre-defined load shedding schedules, unless agreed otherwise in writing between the licensee and the customer in terms of the provisions provided in this document relating to demand response participation, critical loads, load curtailment, or independent power producers. Exclusion of customers for reasons not specified in this document shall be approved in writing by NERSA in terms of the provisions in 4.1.

NOTE 1 Manual load reduction in the event of a system emergency is required in order to prevent the power system from approaching or sliding into an unstable state. The financial implications associated with a national blackout far outweigh the economic cost of manual load curtailment or shedding. The financial impact to a specific customer alone is therefore not sufficient to justify exclusion of individual customer installations from the emergency load reduction. Other considerations related to possible exclusions from load shedding schedules (such as safety and impact on the environment) are addressed in this part of NRS 048 by the requirements related to critical and essential loads. Mechanisms are provided for under this part of NRS 048 in order to reduce the potential impact on customers. These include curtailment options (both voluntary and mandatory), options for customers to cooperate with each other to provide the required reduction, and technology options such as smart metering.

NOTE 2 The definition of mandatory load reduction in the event of a system emergency does not include contracted interruptible load and loads that participate in the demand market (demand response programme). Participation of customers providing such interruptible loads is addressed in this part of NRS 048 (for example, these may under certain conditions be excluded from Stages 1&2 of load shedding or curtailment).

NOTE 3 Broadly equitable participation by customers implies that factors such as practical network constraints, a customer's ability to curtail load, and essential loads requirements should be taken into account. For some customers, the scheduled outage time might have a consequent recovery time depending on their specific application of electrical energy, and so they might be more affected than other customers.

NOTE 4 Exclusions approved by NERSA might be in terms of critical impact at a specific period during the day (e.g. high crime areas), or in terms of related legislation (e.g. as a disaster risk reduction measure where an area is faced with a drought).

NOTE 5 Equitable participation is a requirement that arises from the Electricity Regulation Act.

4.4.3 Principle 3 – Protection of critical and essential loads

Critical loads and essential load requirements shall be taken into consideration in order to limit the potentially negative impacts of mandatory load reduction on safety, the environment, and infrastructure that is critical to communities and the economy.

NOTE It is not always possible for such loads to be excluded from load shedding schedules or mandatory load curtailment. Provisions for such loads are defined in this part of NRS 048.

4.4.4 Principle 4 – Availability of load shedding schedules

Load shedding schedules shall be proactively developed, maintained, and made available to customers.

4.4.5 Principle 5 – Nature of the load shedding schedules

Load shedding schedules should be developed in such a manner so as to ensure maximal standardization across all licensees, whilst still allowing for flexibility to address local conditions.

NOTE For this reason the minimum design requirements for the schedules do not strictly specific all parameters (e.g. some licensees may shed customers for 2 hrs, whilst other licensees may choose to shed customers for 4 hrs. but lass frequently).

Load shedding schedules shall meet the following minimum requirements:

a) coverage over 24 hours per day, all 7 days of the week;

b) time-based, rotational slots of 2 to 4 hours (see NOTES 1, 2, 3);

c) load reduction of 5 % to 6 % for each block (see NOTE 4);

d) rotational timeslots that ensure that customers are not interrupted at the same time each day (see NOTES 5 and 6);

e) all customers shall be on the schedules, with the exception of those provided for in this code of practice; and

f) schedules should where possible be optimized for the seasonal demand profiles (NOTE 6).

Load shedding schedules and curtailment requirements are defined up to a predefined maximum load reduction (see NOTE 7). Where additional load shedding is required, this is regarded as an extreme system condition explicitly excluded from the principles in this section, and which will be handled in accordance with the situation prevalent at the time (see NOTE 8).

NOTE 1 Time-based manual load shedding is chosen for the following reasons:

a) customers generally prefer to know when their supply will be interrupted so that they can better plan their operations and arrangements;
b) the communication of load shedding schedules is less onerous;
c) licensees are able to some extent to pro-actively identify and implement suitable time slots that will lessen the impact on society.

NOTE 2 In the interest of standardization and of limiting the impact of load shedding on the distribution network (due to cold-load pickup), a 2 hr time-slot is recommended for utilities operating networks using remote control systems. Analysis has shown complete loss of diversity of geyser load is less than a 2 hour period. The cold load pick up on urban networks after 2 hour load shedding can be as high as 180% of the normal value. Where switching is done manually, or where engagements with customers suggest otherwise, longer less-frequent periods of load shedding may be considered (e.g. 3 or 4 hrs).

NOTE 3 In the communication of the schedules, common practice is that an additional 30 min is included in the time-slot to allow for rotation (interruption and restoration).

NOTE 4 Schedules are built up using blocks of load. The first stage of shedding uses only one block and subsequent stages use two or more blocks to achieve the load reduction in a given time slot. The requirement for a minimum of 5 % is based on the minimum requirement of the first stage of load shedding, which is 5 %.

NOTE 5 Since there is a difference in the risk of load shedding between peak and non-peak times during winter and summer, equity across peak and non-peak periods is not possible without some sort of rotation or additional scheduling. Licensees are advised to use the suggested block-time rotation described in annexes F, G and H. If the licensee prefers to use other schedule types, then that is allowable as long as the block size remains in accordance with this specification. The licensee must then be able to explain how equity is achieved in their schedule.

NOTE 6 Certain customers may prefer to be in a consistent time slot rather than a rotating time slot. If this can be accommodated without impacting other customers, the licensee may pursue this. The licensee must be able to demonstrate equity across weekdays vs. weekends, peak vs. non-peak periods, customer categories.

NOTE 7 The winter peak is typically between 17h00 and 21h00. This would suggest two 2hr slots or one 4hr slot to be most appropriate in winter with rotation at odd hours in order to avoid unnecessary rotation on half-slots. The summer profile lends itself to a timeslots that rotate at even time slots.

NOTE 8 Load reduction in this document is scheduled and published for the first four stages, Subsequent stages (five to eight) are also scheduled, but these are not published.

NOTE 9 For this level of emergency load reduction to be required, the implementation of all other mitigation actions and initiatives would have been exhausted. This means that the supply constraint is extremely serious and bordering on a total collapse of the entire network load. Under these conditions, the focus is entirely on managing the network from a technical point of view - i.e. to avoid a total loss of load on the entire network. The consequence of a total loss of the system is that cold start sequences will have to be initiated which could take many hours (even days) before load is restored. Therefore technical considerations should take preference over the principles designed to lessen the consequential impact on customers.

4.4.6 Principle 6 – Declaration of a system emergency

Mandatory load reduction in accordance with this part of NRS 048 shall only be instructed under a declared system emergency.

NOTE 1 The declaration of a system emergency is initiated by the System Operator in the case of a national emergency and by the regional or local control room in the event of a regional or local emergency.

NOTE 2 The declaration of a system emergency is an operational requirement instituted to ensure that all parties executing load reduction are clear on the regime under which load reduction is executed. This includes communication of such a declaration to control rooms who execute load shedding and customers who undertake mandatory curtailment.

NOTE 3 A system emergency is a formally declared operating condition under which mandatory load reduction (shedding and/or curtailment) is instructed by the System Operator. The System Operator will under such conditions instruct when load shedding, mandatory load curtailment or both are executed. This means that there may be periods during a system emergency under which the System Operator might find it prudent to lift mandatory load reduction whilst the emergency condition remains in place (e.g. in the early hours of the morning when demand is low).

NOTE 4 Should the System Operator have insufficient time to instruct load shedding or curtailment, the System Operator will take any measures it deems necessary to ensure the security of the power system in terms of its mandate under the the Grid Gide. This may include manually interrupting customers to manage demand until an emergency can be declared and the provisions of this part of NRS 048-9 can be invoked.

4.4.7 Principle 7 – Minimized impact on customers

The execution of mandatory load reduction should be undertaken in a pragmatic manner in order to minimize the expected impact on customers, subject to the necessary system load reduction requirements being met. This includes:

a) the consideration of the expected load reduction requirements related to the winter and summer load profiles (see NOTE 1); and

b) pragmatic decision making when calling on load shedding and or mandatory load curtailment (see NOTE 2).

NOTE 1 The System Operator should, where possible, instruct load shedding to be initiated at times at which schedules are rotated (on the hour). In cases where an immediate response is required, this may not possible.

NOTE 2 Under some system conditions:

a) Load shedding may not be required if load curtailment has already been instructed and the load reduction is adequate to meet the system requirements. Under such conditions, load shedding might not be called on;
b) Mandatory load curtailment may not be appropriate if the load reduction requirement is for a limited period of time (given the 2hr notice period required to implement curtailment). Under such conditions, load shedding might only be called on (given the 10-30min implementation time);
c) A full stage of load reduction may not be required, in this case the System Operator may not call on all control rooms to shed load. The rotation of control rooms would in this case be necessary to ensure that the principle of equitable participation is met. For this to be effective the System Operator must have insight into the likely shedding volume of each control room for each load shedding period; and
d) Under some system conditions, mandatory load reduction may be called on proactively to manage reserves and thereby limit the depth of expected load shedding later in the week.

4.4.8 Principle 8 – Predictability and advance warning of load reduction

The execution of mandatory load reduction should be undertaken in a manner that maximizes the predictability for customers and for those executing the load reduction, subject to the necessary system load reduction requirements being met. Predictability and advance warning should be addressed by:

a) the provision of warnings and alerts to control rooms and customers of periods of heightened probability of mandatory load reduction; and

b) the pragmatic implementation of planned load shedding in the case of extended periods under which the system is expected to be constrained (see scenario C in Figure 2).

NOTE 1 Planned load shedding refers to the advance announcement of load reduction stages to be implemented for specific days over an extended period of time (weeks to months). Under such conditions, calling on ad hoc load reduction would be significantly more disruptive and frustrating to customers.

NOTE 2 Application of planned load reduction is most appropriate under scenario C in Figure 2. NRS048-7 addresses the requirements for planned load reductions (a minimum of 48 hrs. notice is required). Application of load reduction to manage real-time reserves under scenario B in Figure 2 requires real-time decision-making, under which advance warning of 8-12hrs is more appropriate when implementing weekend load reduction.

NOTE 3 Given the unpredictable nature of real-time variations in system conditions, a focus on predictability may mean that load shedding is implemented at times and at levels that this reduction is not absolutely necessary for the system. On the other hand, it is possible that deeper levels of load reduction may be required, should system conditions deteriorate beyond that expected. A decision to implement planned load shedding needs to be taken prudently, considering both the system risks and need to limit the impact on customers.

4.4.9 Principle 9 – Customers participating in load reduction

Customers who participate voluntarily in formal, real-time load reduction products designed to avoid declaration of a system emergency shall be excluded from early stages of load shedding in accordance with the provisions of this part of NRS 048.

NOTE Should the power system be constrained, voluntary participation in load reduction may be called on to avert a system emergency. Examples of such products include the supplemental demand response (SDR) and instantaneous demand response programme based on the SO requirements.

NOTE Load reduction achieved under a scheme designed to manage a longer term energy constraint is not considered as emergency load reduction, as this is unable to respond to real-time system requirements. Unless otherwise determined in the rules of such a scheme, a customer will still be required to reduce load under a system emergency, in accordance with the requirements of this part of NRS 048.

4.5 Load reduction in the event of a national supply constraint

4.5.1 Requirements and stages of load reduction

The specific reduction in load required to stabilize the system under a national supply constraint will be dictated by the power system conditions that prevail at the time. However, in order to facilitate the development of load shedding and curtailment schedules that can be made available to the public, pre-determined stages of load reduction are specified in this part of NRS 048 (see table 2). These stages range from stages 1 to 4 (scheduled load shedding and notified mandatory curtailment).

Emergency load reduction under an extreme supply constraint (i.e. beyond Stage 4) should be executed through implementing the extended schedules and curtailment requirements detailed in section 5. Whilst these contingency schedules shall be available to the control room staff, communication of these to the public is not required unless otherwise instructed by NERSA in terms of section 4.3.

The level of reduction required under stages 1 to 4 is defined at each stage as a percentage of national load (see Table 1). This reduction is achieved by both load shedding (according to pre-defined schedules) and by reduction required from customers eligible for notified curtailment (see NOTE). Under a system emergency, the System Operator shall declare the applicable stage of load shedding.

NOTE Customers may offer load curtailment instead of being shed, subject to:

a) the specific conditions listed in 4.5.3.2; and
b) an agreement between the customer and the licensee.

Where a customer has responded to a request for voluntary load reduction shortly before declaration of an emergency, the licensee should endeavour to deduct from the customer's contribution during stages 1 and 2 the prior contribution to load reduction.

Table 2 — National load reduction requirements (load shedding and curtailment) under a system emergency declared by the System Operator in the event of a national generation capacity constraint .

1	2	3	4
Stage	**Type**	**Reduction required from end-use customers by *load shedding*** (see footnotes [a b c])	**Reduction required from end-use customers eligible for *curtailment*** (see footnote [d])
Stage 1	Scheduled (notified)	All Stage 1 load scheduled by utilities, approximately 5 % reduction in load profile of the national non-curtailment load (e.g. ±1 000 MW at system peak)	10 % reduction in normal demand profile within the agreed notification period and for the duration instructed
Stage 2	Scheduled (notified)	All Stage 2 load scheduled by utilities, approximately 10 % reduction in load profile of the national non-curtailment load (e.g. ±2 000 MW at system peak)	
Stage 3	Scheduled (notified)	All Stage 3 load scheduled by utilities, approximately 15 % reduction in load profile of the national non-curtailment load (e.g. ±3 000 MW at system peak)	15 % reduction in normal demand profile within the agreed notification period and for the duration instructed
Stage 4	Scheduled (notified)	All Stage 4 load scheduled by utilities, approximately 20 % reduction in load profile of the national non-curtailment load (e.g. ±4 000 MW at system peak)>	20 % reduction in normal demand profile within the agreed notification period and for the duration instructed

[a] The national load reduction (shedding and curtailment) requirements in this table are allocated to each distribution licensee in accordance with the procedure specified in 4.5.2.

[b] Licensees are required to develop load shedding schedules that follow the natural load profile of their system, providing the full allocation at peak,

[c] The required reduction may be rounded to a specific number of megawatts (e.g. 1 000 MW rather than 980 MW).

[d] Customers who comply with the requirements in 4.5.3.2 may elect to curtail load as specified rather than be shed.

[e] The curtailment indicated here is mainly from systems such as geyser control, voltage reduction schemes, use of municipal generation offered by licensees and applies to customers who would otherwise be shed under subsequent stages (i.e. the load reduction provided is likely to already be included under subsequent stages, should these be required).

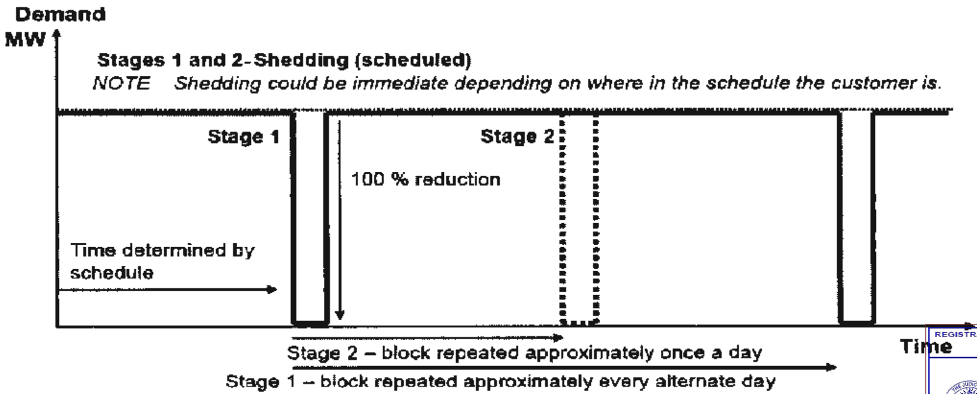
[f] Load reduction under a severe supply constraint is addressed in accordance with section 5.

Figure 5 illustrates the options available to eligible customers, based on the general requirements in Table 2. These options are detailed in 4.5.2 to 4.5.4.

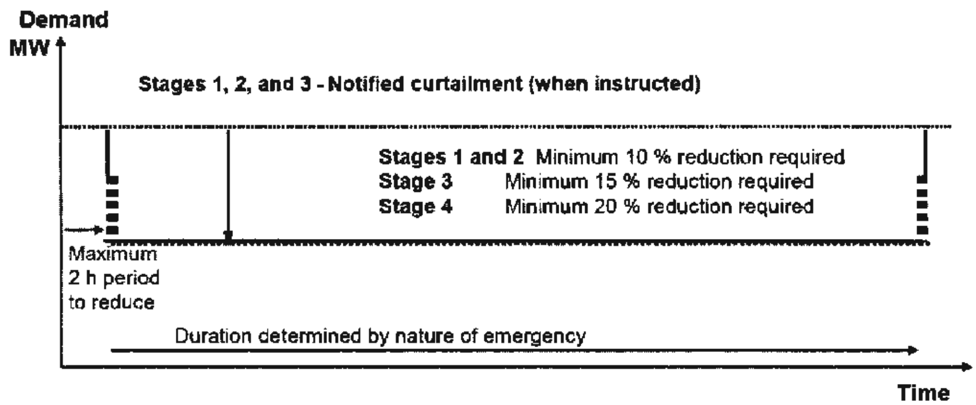
Customers who are eligible for curtailment shall be required to select an option up-front. This decision should be informed by the scenarios illustrated in Figure 2 and detailed in Table 1.

NOTE 1 The need to have stable schedules does not allow customers to select a curtailment option at the time of any emergency.

NOTE 2 Annex C provides practical approaches to addressing the needs of individual customers who are not eligible for curtailment. These may involve up-front costs that should be paid by the customer(s) concerned.



(a) Stages 1 and 2 rotational load shedding (stages 3 and 4 are similar, but at more regular intervals).



(b) Stages 1, 2, 3 and 4 notified curtailment for eligible customers

Figure 5 — Summary of load reduction options – a) Shedding or b) notified curtailment

4.5.2 Load shedding (Stages 1 to 4)

4.5.2.1 All customers shall be on the load shedding schedules, with the exception of

a) critical loads and loads with essential load requirements, where such exceptions are provided for under conditions set out in this part of NRS 048 (see clauses 6 and 7);

b) loads that comply with the requirements for notified curtailment (see 4.4.2 and 4.4.4);

c) some loads that participate in the merit order (see 4.4.6);

d) where alternative reduction options have been agreed with the licensee and approved by NERSA (see 4.1); and

e) loads where exemptions have been pre-approved by NERSA.

Load shedding shall be executed in accordance with published schedules. Schedules shall be prepared for stages 1, 2, 3 and 4 in accordance with the requirements in 4.6.

4.5.2.2 Although utilities would establish time-based schedules using specific time slots (as specified in Annexure H), customers may engage with utilities to consider alternatives such as doubling the duration of being shed, whilst reducing the frequency of such shedding. Such discussions need to be finalized well before an emergency to ensure that the schedules are adapted for this request. Such requirements may not in all cases be possible for the licensee to meet.

Typical cases in which these may be accommodated are:

a) where all the customers on a feeder agree on a similar requirement;

b) where the customer can be isolated; and

c) where a large customer is able to absorb the total load reduction requirement of a licensee. there would an agreement between the large customer and the other customers within the area of supply

Where a customer indicates as such, supplies that rely on each other should be considered in developing schedules.

4.5.3 Notified mandatory load curtailment (Stages 1 to 4)

4.5.3.1 A licensee may identify specific customers who, instead of being shed, can provide a pre-defined amount of load to be curtailed within a maximum of 2 h on instruction from the licensee.

NOTE 1 Given the requirements below, these will typically be larger customers.

NOTE 2 Such curtailment is not subject to payment, as might be the case in demand market participation schemes. The latter involves use of demand curtailment options much earlier in the merit order, where use of such options is determined at the time in the context of other demand and supply options (generally on a least-cost basis).

4.5.3.2 Customers who comply with the following requirements are eligible and should be accommodated for notified load curtailment under stages 1, 2, 3 and 4:

a) the customer shall be able to offer at least 10 % of normal load for curtailment under stages 1 and 2, 15 % of normal load under stage 3 and 20 % of normal load under stage 4;

b) this curtailment shall be maintained for the duration of the emergency, or as otherwise instructed by the System Operator during the system emergency (see NOTE 1);

c) the curtailment shall be effected within an agreed time frame (notification time) based on the nature of the customer installation. The time-frame shall be 15 min to a maximum of 2 hrs (NOTE 2);

d) the curtailment shall not affect the integrity of the national under-frequency load shedding scheme. For customers with under frequency loads on their premises the customer shall indicate which load is curtailed to obtain the required load reduction to confirm that the under-frequency scheme is not compromised. If it is the same load the customer shall supply an alternative load to be allowed to curtail;

e) the required load curtailment can be measured and verified;

f) the customer's essential load requirement is met through this curtailment (Note 3);

g) protection of this customer from load shedding shall not result in the need to exclude significant other load from load shedding due to network limitations (i.e. recognizing this customer might not be on the same circuit as other customers that are on the load shedding scheme). Where this customer represents over 80% of the load supplied by a specific feeder, curtailment provided by this customer may be considered adequate. Where this criterion is not met, and where the customer can offer the equivalent load for curtailment, curtailment may be considered; and

h) actual load curtailment instructed during an event complies with the requirements agreed upon with the licensee.

NOTE 1 Where an emergency is declered for several days, the System Operator may allow curtailment loads to return during periods of low demand, where the requirements to replenish reserves have been met (typically between 10 pm and 6 am the next morning).

NOTE 2 For example, where a residential estate participates in load curtailment, this should be in the same time-frame as load shedding – i.e. within 15 min of the instruction being given. On the other hand, a deep level mine may require 2hrs notification before the reduction is provided.

NOTE 3 Where it can be demonstrated that the essential load requirement can at times during the operating cycle not be met given the reduction required in each of the stages, the customer may engage the licensee on alternative options to provide demand reduction in a manner that ensures equity.

Where such conditions are not met, a customer shall not be eligible to be removed from the load shedding schedules (and may be placed back on the schedule if the actual load curtailment is not achieved during an event).

4.5.3.3 The base line for determining the percentage reduction shall be in accordance with Annex I, or as otherwise agreed between the customer, the licensee, and the System Operator.

4.5.3.4 Customers who participate under the notified load curtailment scheme

a) shall be excluded from load shedding schedules (Stages 1 to 4); and

b) shall not exceed normal demand profile for 12 h after the emergency with the exception of the periods between 23h00 and 04h00 the next morning.

4.5.3.5 Customers who can demonstrate the ability to manage the required percentage reduction across several independent installations in a given supply area may be accommodated (e.g. a customer or group of customers may agree to completely close down one plant while other plants remain in operation). This arrangement applies to a national emergency (load reduction requirement), and should not compromise the specific requirements for regional load shedding in the event of a regional load shedding requirement (i.e. local supply constraints).

4.5.3.6 A licensee may use preferred load curtailment information provided by several independent customers to develop a co-ordinated load curtailment plan. This plan shall demonstrate the ability to manage the required percentage reduction across several customers within a single licensee's area of control (i.e. a customer may choose to completely close down one plant while other customers remain in operation). A licensee cannot guarantee that the notified requirements for load curtailment can be accommodated in such a plan. In cases where combined offerings are required over multiple licensee areas, then this should be handled through the exemption process (refer 1.4).

NOTE A survey of large customer curtailment preferences has indicated that even within the same sector, customers sometimes have different preferences – i.e. some customers may prefer to curtail by 80 % for a day and then resume normal operations, rather than reducing by 10 % or 20 % for several days should the emergency last this long.

4.5.3.7 In the event that a customer does not achieve the load curtailment requirements during an emergency, the licensee shall have the right to shed the customer after reasonable notice has been given, and to place the customer on the load shedding schedule going forward.

4.5.4 International customers

4.5.4.1 Cross-border load to other utilities supplied by South African generators shall be treated equitably with South African customers in the event of national or regional load reduction. Cross-border load reduction requirements should be (at least) the same percentage as the load reduction required in South Africa – i.e. the sales from South Africa to these countries shall be reduced by the same amount under the reduction instructed.

H

NOTE This requirement implies that during a national emergency, energy sales from South Africa will be reduced.

4.5.4.2 In the event that power is wheeled through the South African network from one country to another, the reduction requirement would not apply. In the case of an emergency in the Southern African region, a reduction might, however, also be required in power wheeled through South Africa.

4.5.5 Exclusions based on participation in the merit order

4.5.5.1 Where interruptible load has been contracted on a commercial basis as part of the merit order (i.e. in terms of a special pricing agreement or in terms of demand market participation), these loads may be excluded from the first two stages of manual load reduction schedules in accordance with the requirements in section 4.5.5.3. Under emergency conditions, specific agreement may be reached with these customers on further load curtailment.

NOTE Interruptible load is required by the System Operator also during emergencies to manage short-term variations on the system.

4.5.5.2 The System Operator (or its agent) shall advise each licensee of all contracted Demand Response Participants embedded within that licensee's networks.

4.5.5.3 Where it is technically feasible to isolate such customers, customers on supplemental demand response may be excluded from Stage 1 and 2 load reduction under the following conditions:

a) the customer shall participate with a minimum of 25 % of their average MW load (Annexure I). The customer's average MW load is based on the consumption between 05h00 and 22h00, weekdays only;

b) the customer shall be available and assist when called at least 150 times per annum/contract period;

c) the minimum load reduction event period shall be 2 hours;

d) the load reduction performance when called upon shall be at least 90 % of the reduction required under normal plant conditions;

e) where the customer's processes and/or technologies do not allow them to reduce 25 %, the customer shall participate with the same volume energy not consumed. This might mean that the customer is required to participate more than 150 times per annum or reduce for longer event hours. Under these conditions, the minimum requirement is for the customer is to provide at least 20 % of their average MW load;

f) where customers are able to provide SDR above 25 % at a particular plant, they may carry over the additional reduction beyond 25 % to other plants within their group; and

g) these customers shall participate in Stage 3 and 4 load curtailment.

4.5.5.4 Where it is technically feasible to isolate such customers, customers on Instantaneous demand response may be excluded from Stage 1 and 2 load reduction under the following conditions:

a) the customer shall participate with a minimum of 25 % of their average MW load (Annex I). The customer's average MW load is based on the consumption between 05h00 and 22h00, weekdays only;

b) the customer shall be available and assist when called at least 200 days per annum/contract period;

c) the available amount of times a day shall be at least 2 events;

d) the maximum load reduction event period shall be 10 min;

e) the load reduction performance when called upon shall be at least 90 % of the reduction required under normal plant conditions;

f) IDR provides protection from stage 1 and 2 curtailment only at plant level. Customers may not carry over additional reduction to other plants within the same group; and

g) these customers shall participate in Stage 3 and 4 load curtailment.

Table 3 — Exemption rules for customers participating in a contracted demand response programme. (NOTE This excludes participation in the automatic under-frequency protection scheme and residential demand response)

1	2	
Type	**Exemption rules**	
	Requirement	**Exemption**
Supplementary demand response (SDR)	25 % of average demand, at least 150 times per annum, for at least 2hrs (or equivalent volume of energy as in 4.4.6.3)	Stage 1 and 2
Instantaneous demand response (IDR)	25 % of average demand, at least 200 days per annum, at least twice a day for up to 10 min	Stages 1 and 2
NOTE 1 The SDR exemption may be applied at plant or group level, whilst the IDR exemption shall only be applied at plant level. NOTE 2 Both the SDR and IDR contracts will limit the maximum usage. The requirement indicated is the threshold for exemption.		

4.5.5.5 The System Operator shall determine how much supplemental or instantaneous demand can be contracted for a given period.

4.5.6 Interruptible load as a term of contract

Where interruptible load is a general requirement under the contract, and not applied commercially as part of the merit order, this shall be considered as load curtailment – however, the customer shall comply with all the requirements under load curtailment to be kept off the load shedding schedules.

4.6 Load reduction requirements in the event of a regional emergency

Given the difficulty in determining the specific areas affected in the event of a regional or local network capacity constraint, specific load reduction requirements are not pre-determined.

However, where possible in the event of a regional supply constraint, load reduction should be undertaken using the schedules developed for national load shedding.

If not possible, then emergency plans pertinent to particular areas should include locally relevant load shedding schedules.

NOTE The nature of a regional or localized event might require higher stages of load shedding at peak periods.

4.7 Execution of emergency load reduction

4.7.1 Conditions for the declaration and lifting of a system emergency

4.7.1.1 The declaration of a system emergency is a requirement for implementing manual mandatory load reduction (load shedding and/or load curtailment) as defined in this part of NRS 048.

4.7.1.2 The declaration of a system emergency shall be made by the System Operator in the event of a national power system constraint.

4.7.1.3 Once a system emergency has been declared, the initiation and termination of load shedding and/or curtailment shall be executed under the instruction of the System Operator.

NOTE 1 The declaration of a system emergency does not automatically mean that the initiation of load shedding or curtailment has been instructed by the System Operator. The initiation, termination, or change of stage of load reduction is specifically instructed under a system emergency.

NOTE 2 The declaration of a system emergency is an operational protocol. The manner in which this is communicated externally is addressed in section 4.7.3.

4.7.1.4 Conditions under which the System Operator might declare a system emergency include, but are not limited to, the following:

a) should the power system immediately enter a state of collapse;

b) should the system begin to proactively approach a state of collapse (i.e. where reserves need to be prudently managed in terms of the System Operator's mandate to ensure the security of the national power system); or

c) on a planned basis to address a medium to long-term system constraint, where no alternative load reduction protocols have been approved by NERSA, and where at least 48 hrs. notice has been provided to NERSA, customers, and stakeholders (see 4.6.5).

4.7.1.5 The System Operator shall lift the declared system emergency once the constraint is lifted.

4.7.2 Power system alert protocol and early warning

4.7.2.1 In the event of a high risk of national load shedding, the System Operator shall issue a "Power System Alert" instruction to Eskom Distribution control centres, who in turn should issue this instruction to all municipal control centres that undertake their own load reduction.

NOTE 1 Such an instruction is generally given telephonically and recorded digitally.

NOTE 2 The System Operator may also at times choose to issue a "Power System Early Warning" communication when system conditions can be expected to deteriorate to the point where a formal Alert instruction might be issued. Such a communication does not require a formal action by downstream control rooms.

4.7.2.2 In the event that a "Power System Alert" instruction has been issued by the System Operator, all control rooms shall prepare for the execution of load shedding at short notice.

4.7.3 Power System Emergency protocol and implementation of load reduction

4.7.3.1 In the event that national load reduction will be initiated, the System Operator shall issue a "Power System Emergency" instruction to Eskom Distribution control centres, who in turn should issue this instruction to all municipal control centres that undertake their own load reduction.

NOTE Such an instruction is generally given telephonically and recorded digitally.

4.7.3.2 When instructing the initiation of emergency load reduction, the System Operator shall specify:

a) the applicable stage of load reduction;
b) whether load curtailment, load shedding or both are being implemented;
c) the time at which load shedding shall commence, and, if applicable; and
d) the time by when load curtailment shall commence and by when the required reduction should be in place, bearing in mind the minimum notice period required.

When instructing the termination of emergency load reduction, the System Operator shall specify:

a) the time at which load shedding should be terminated; and
b) the time, from which curtailment customers may begin to pick up load again.

4.7.3.3 An instruction to terminate load reduction shall be accompanied by the time at which the control center may begin restoring load that has been shed.

4.7.3.4 All control centres shall report to their upstream control rooms:

a) when the load under the instructed Stage has been shed and approximately how much has been shed (MW); and

b) when all the load has been restored after the instruction to restore.

NOTE In order to manage the system frequency during the restoration of load, not all control rooms might be instructed to return load at the same time by the System Operator.

4.7.4 Use of load curtailment vs. load shedding, load limiting and load switching

The System Operator shall determine if load shedding (as well as load limiting and load switching), notified load curtailment, or both methods of load reduction will be instructed, based on the following guidelines:

a) In the event of the need for an immediate load reduction, load shedding (as well as load limiting and switching) will most likely be required, given the response time (15 min -30 min);

NOTE Should load shedding be called over an evening peak, it is possible that load curtailment may not be required, as the longer time required for load curtailment will be unable to meet the load reduction requirement.

b) In the event of a pro-active declaration of an emergency, the applicable notice should be given to affected customers at what time load curtailment is instructed. The instruction to prepare for load shedding should be issued to all control centres, however the instruction to proceed with load shedding might be instructed only should system conditions require this;

NOTE Should load curtailment be called before evening peak, it is possible that load shedding may not be required if the load reduction obtained from curtailment and public announcement of the system emergency is adequate.

c) That for the purpose of meeting the winter peak, load shedding (as well as load limiting and switching) may be implemented, without curtailment, provided that the expected load reduction is either Stage 1 or Stage 2. Where a load reduction of greater than Stage 2 is anticipated at least 2 hrs. before the constraint, the System Operator should call on the appropriate level demand curtailment 2 hrs. before the expected constraint;

d) Stage 3 or 4 load curtailment should not be instructed without at least load shedding (as well as load limiting and switching) (Stages 1 and 2) having also been implemented or anticipated; and

e) Load curtailment should not be implemented for a period of more than 24 hrs. without load shedding (as well as load limiting and switching) also having been implemented.

4.7.5 Managing medium/long-term system constraint

4.7.5.1 Noting the potentially negative impact of regular but unpredictable load reduction on customers, in the absence of an alternative load reduction protocol approved by NERSA, the following approach should be adopted in managing medium- to long-term system constraints:

a) planned load reduction (shedding and/or curtailment) may be implemented by the System Operator to improve predictability for customers where load shedding is required for extended periods of time (weeks to months);

b) where possible, customers shall be informed day(s)/week(s) ahead in advance of the expected load reduction regime (i.e. the expected load reduction Stage and applicable schedules to be implemented). This notwithstanding that system conditions and operational requirements on the day may at times result in variance from the communicated reduction regime; and

c) planned load reduction may be deployed by the System Operator before use of some peaking plant and reserves in order to: (i) limit the variance from the communicated load reduction regime and (ii) ensure adequate operating and emergency reserves in managing the security of the national power system.

4.7.5.2 Noting the requirements of the related regulatory standard NRS 047, the following approach should be adopted when pro-actively implementing planned load reduction in the event of a medium-to long-term system constraint:

a) Eskom shall inform NERSA in writing of the reasons for such actions within at least 48 hours before the planned implementation;

b) Where time permits and the security of the power system is not at immediate risk, Eskom shall provide its customers with advance notification of the intent to implement planned load reduction, with a minimum notice period of at least 48 hours in advance; and

c) This notification shall include the expected start time and period(s) of load reduction.

4.8 Load shedding schedules

4.8.1 General requirements

4.8.1.1 Licensees shall be responsible for the development and maintenance of their load shedding schedules, and for communicating these to their customers.

4.8.1.2 Maintenance of the schedules should include ad hoc revisions in response to changes in the operating environment, as well as a formal review every year.

4.8.1.3 Where the supply areas of one or more licensees adjoin one another, the licensees should take account of the need for co-ordination when load shedding is being scheduled - particularly in respect of factors such as traffic flows, and fuel and sewage pumping.

4.8.1.4 An individual licensee may choose to be completely shed instead of implementing its own rotational shedding. This shall be undertaken in consultation with the upstream licensee supplying this licensee. The final arrangement shall not negatively impact on the integrity of the load shedding regime. The licensee shall remain responsible for communicating schedules to its customers, and for managing the critical and essential load requirements of its customers.

4.8.1.5 The national load shedding allocations shall be agreed between the upstream and downstream utilities at least annually.

4.8.1.6 Audits may be undertaken by the System Operator from time to time to provide assurance that the self-rotating utilities can demonstrate the ability to load shed as described in this code of practice. Licensees must be able, on request, to demonstrate to the System Operator and NERSA that the schedules meet the requirements of this code of practice.

4.8.1.7 The latest schedules shall at all times be immediately available to operational staff.

4.8.2 Design of load shedding schedules

4.8.2.1 The load base to be shed (sheddable load) shall be determined for each stage as follows:

g
JA

a) each control centre shall determine the load (in MW) under its control based on the previous year's peak demand;

b) from this load, critical loads, international loads, and any loads that form part of the merit order that are explicitly excluded from shedding served under the stage of shedding by the control centres shall be subtracted to obtain the base load on which the required reduction for that control centre is determined;

c) the load to be shed by each control centre shall be determined by subtracting the load under curtailment from the control centre's base load. This is the non-curtailment load; and

d) each control centre shall follow the schedule requirements and submit the resulting load block size for each of the four scheduled stages to the upstream control centre.

4.8.2.2 Licensees shall build load shedding blocks based on the normal feeder annual peak demand associated with a particular feeder breaker (see NOTE 2). Licensees should take into consideration potential diversity between feeder demands so as to ensure that the overall reduction complies with the requirement in each time slot.

NOTE 1 This pragmatic approach is taken for the reasons summarized in annex D. Where the actual load reduction might not be sufficient at certain times of the day, the System Operator (or regional control centre in the case of regional events) will compensate by making adjustments to the stage of shedding instructed.

NOTE 2 Normal annual peak demand excludes operating conditions where a feeder is used to supply (back feed) loads that are not normally associated with that feeder.

4.8.2.3 Annexures F, G and H provide guidelines for the development of schedules.

4.8.2.4 Where a customer prefers to be shed repeatedly at the same time of the day for successive manual load shedding events, as opposed to the rotation of time slots, where possible this may be provided for. This subject to the licensee ensuring that the impact on affected parties is not significant, and that schedules can be adapted to accommodate this.

NOTE For example: (i) in respect of traffic signals, to mitigate interruptions to city centres during peak traffic times, (ii) in respect of interdependent companies that work in the same sector such as manufacturing processes dependent on air products.

4.8.2.5 If practical, schedules may be adjusted to accommodate customers who prefer to be shed for a longer period of time, but less frequently.

NOTE For example, where several of such customers can be coordinated to provide the necessary load reduction over the various days.

4.8.3 Technology solutions as an alternative to load shedding

4.8.3.1 Where technology options such as curtailment using load limiting relays become available, the schedules shall be revised accordingly.

NOTE For example, larger residential areas may rather be subject to curtailment than shedding for the same load requirement to be achieved.

4.8.3.2 A licensee may choose whether to use load limiting on a rotational basis using schedules or to apply load limiting to all customers at the same time.

4.8.4 Addressing under-frequency protection requirements in schedules

4.8.4.1 The integrity of automatic under-frequency protection schemes shall be maintained during load shedding and curtailment. The approach taken by various licensees may differ as long as the integrity of the national automatic under-frequency load shedding scheme is maintained. (see Annex A).

a) each control centre shall determine the load (in MW) under its control based on the previous year's peak demand;

b) from this load, critical loads, international loads, and any loads that form part of the merit order that are explicitly excluded from shedding served under the stage of shedding by the control centres shall be subtracted to obtain the base load on which the required reduction for that control centre is determined;

c) the load to be shed by each control centre shall be determined by subtracting the load under curtailment from the control centre's base load. This is the non-curtailment load; and

d) each control centre shall follow the schedule requirements and submit the resulting load block size for each of the four scheduled stages to the upstream control centre.

4.8.2.2 Licensees shall build load shedding blocks based on the normal feeder annual peak demand associated with a particular feeder breaker (see NOTE 2). Licensees should take into consideration potential diversity between feeder demands so as to ensure that the overall reduction complies with the requirement in each time slot.

NOTE 1 This pragmatic approach is taken for the reasons summarized in annex D. Where the actual load reduction might not be sufficient at certain times of the day, the System Operator (or regional control centre in the case of regional events) will compensate by making adjustments to the stage of shedding instructed.

NOTE 2 Normal annual peak demand excludes operating conditions where a feeder is used to supply (back feed) loads that are not normally associated with that feeder.

4.8.2.3 Annexures F, G and H provide guidelines for the development of schedules.

4.8.2.4 Where a customer prefers to be shed repeatedly at the same time of the day for successive manual load shedding events, as opposed to the rotation of time slots, where possible this may be provided for. This subject to the licensee ensuring that the impact on affected parties is not significant, and that schedules can be adapted to accommodate this.

NOTE For example: (i) in respect of traffic signals, to mitigate interruptions to city centres during peak traffic times, (ii) in respect of interdependent companies that work in the same sector such as manufacturing processes dependent on air products.

4.8.2.5 If practical, schedules may be adjusted to accommodate customers who prefer to be shed for a longer period of time, but less frequently.

NOTE For example, where several of such customers can be coordinated to provide the necessary load reduction over the various days.

4.8.3 Technology solutions as an alternative to load shedding

4.8.3.1 Where technology options such as curtailment using load limiting relays become available, the schedules shall be revised accordingly.

NOTE For example, larger residential areas may rather be subject to curtailment than shedding for the same load requirement to be achieved.

4.8.3.2 A licensee may choose whether to use load limiting on a rotational basis using schedules or to apply load limiting to all customers at the same time.

4.8.4 Addressing under-frequency protection requirements in schedules

4.8.4.1 The integrity of automatic under-frequency protection schemes shall be maintained during load shedding and curtailment. The approach taken by various licensees may differ as long as the integrity of the national automatic under-frequency load shedding scheme is maintained. (see Annex A).

4.8.4.2 In the absence of a specifically designed method, the following procedure shall be applied to address the implications of load being shed or curtailed also being required for under-frequency load shedding during a particular stage:

a) each control centre should determine the load under its control;

b) for the first 10 % of system load required for automatic under-frequency load shedding, a percentage of this total requirement shall be allocated to various time slots on the load shedding schedule; and

c) a proportionate increase in the available load for the under-frequency load shedding scheme shall then be implemented to address the load that may not be available in any given time slot.

The System Operator shall specify the maximum and minimum deviations from the planned automatic reduction as part of the under-frequency scheme specifications.

An example of coordinating under-frequency load shedding scheme requirements with load shedding schedules is provided in Annex A.

4.8.5 Changes to load shedding or curtailment schedules

The ability to adjust schedules is important to limit the societal impact of load shedding. Such adjustments may be

a) planned – in accordance with 8.6.6, certain sites may be removed from the schedules, or

b) unplanned – for example in response to a concern raised during load shedding with respect to a critical load.

4.8.6 Catering for special events

4.8.6.1 In the case of special events (such as national and international events that involve large numbers of people), certain loads may be temporarily protected from load shedding.

NOTE The implication is that more load shedding will be required in other parts of the network for the duration of the special event.

4.8.6.2 It is the responsibility of the licensee to revise its schedules to ensure that the required load to be shed is available.

4.8.6.3 In exceptional cases of national or regional interest, an agreement may be reached with the System Operator for selected sites may be removed temporarily for the duration of the event without implementing 4.8.6.5.

4.8.7 Catering for non-electricity related emergencies

4.8.7.1 In the case of emergencies that require electricity to be maintained to a given supply area, certain loads may be temporarily protected from load shedding.

NOTE Examples include where this is a disaster risk mitigation or, where significant security incidents are being managed.

4.8.7.2 Such temporary protection and the impact on the reduced load expected to be shed shall be agreed with the System Operator.

4.8.7.3 Where the incident is of a duration of more than 21 days, the System Operator may require the schedules to be revised to provide the require load reduction.

4.9 Operational information exchange

4.9.1 Information related to the implementation of load shedding schedules

4.9.1.1 Eskom Distribution control centres shall provide the System Operator with information on the manner in which load reduction requirements have been implemented for the various stages as and when required by the System Operator.

4.9.1.2 Municipal and metropolitan control centres shall provide the Eskom Distribution control centres with information on the manner in which load reduction requirements have been implemented for the various stages as and when required by the Eskom Distribution control centre.

4.9.2 Real-time information on the system status

4.9.2.1 The System Operator shall make daily system status information available to regional, municipal and metropolitan control centres.

NOTE This information might also be made available to curtailment customers.

4.9.2.2 This information shall provide an indication of the expected need for emergency load reduction for the day.

NOTE At the time of publication of this part of NRS 048, technical information on the weekly system status can be found at www.eskom.co.za (i.e. the system adequacy report).

4.10 Communication with customers and stakeholders

4.10.1 Information related to load shedding schedules

4.10.1.1 All licensees shall make load shedding schedules available to their direct customers. An appropriate mechanism for communicating changes to schedules should be implemented.

4.10.1.2 Licensees who do not shed their own customers (i.e. shedding is executed by the licensee supplying them), shall remain accountable for the communication of load shedding schedules to their direct customer.

NOTE Such schedules may be published in print media, made available on a website, or attached to electricity bills.

4.10.2 Prior notice of mandatory load reduction under a system alert

4.10.2.1 Licensees should, where practicable, notify their direct customers when the System Operator has issued notice that load shedding or curtailment has been or is expected to be implemented.

4.10.2.2 In the case of critical loads, specific communication requirements related to impending load shedding are prescribed in clause 7.

4.10.2.3 Where practicable, licensees should inform curtailment customers by direct communication (e.g. SMS, telephone, email) when there is a high probability that load shedding or curtailment may implemented.

4.10.2.4 Licensees are encouraged to identify other customers who will be notified by direct communication (e.g. SMS, telephone, email), whilst the bulk of customers may receive such communication through media primarily such as radio and television.

NOTE If, for example, a national generation capacity shortage is expected at evening peak, such notification may be issued during the day. However, if such a shortage was unexpected, the notification period may be short.

4.10.3 Notice of mandatory load reduction implemented under a system emergency

4.10.3.1 The media shall be informed when mandatory load reduction or curtailment is being implemented. This information shall include the stage of load reduction implemented, the start time, and the expected duration (or end time).

NOTE In the case of national load shedding, such media communications is the responsibility of Eskom. In the case of mandatory load reduction due to a constraint within municipal boundaries, it is the responsibility of the municipal authority to communicate this to the media.

4.10.3.2 Notified curtailment customers that have signed agreements in this regard shall be instructed to implement mandatory load curtailment via the agreed protocol (typically verbal instruction). These customers shall also be provided notification in writing retrospectively that a System Emergency was declared, based on communications to this effect provided by Eskom in the event of a national or provincial constraint, and the licensee in the case of a local constraint.

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA

NOTE Whilst declaration of a System Emergency is primarily an operational requirement, curtailment customers require notification in writing that a System Emergency was declared in the event that insurance claims arise from the execution of (self) curtailment.

4.10.4 Information related to the system status

Information on the general status of the system shall be made available by the System Operator to customers. Such information should include:

a) anticipated system constraints for the next 3 months;
b) week-a-head system status; and
c) system status on the day.

NOTE 1 This information may assist customers in making decisions regarding the operation of their plant. However, by the nature of certain types of system events, a healthy system status report is no guarantee that an emergency cannot occur at any time after the report has been issued.

NOTE 2 At the time of publication of this part of NRS 048, technical information on the weekly system status can be found at www.eskom.co.za (i.e. the system adequacy report).

4.10.5 Information related to unplanned interruptions to customers

4.10.5.1 Licensees should make information available to customers about networks that are affected by unplanned interruptions during load shedding. This information should include the affected areas and expected time of restoration of supply.

4.10.5.2 Licensees should make information available to the media on request about networks that are affected by unplanned interruptions during load shedding.

NOTE Unplanned interruptions may occur from time to time during periods of load shedding that impact the perceived time and duration of load shedding negatively.

4.11 Reporting

4.11.1 Real-time operational reporting

The following reporting shall be implemented on a daily basis during load shedding:

a) the municipal control room shall for each time period report to the Eskom control room the estimated amount of load shed, the expected load curtailed and, where relevant, the additional generation used in lieu of load reduction; and

NOTE The actual curtailed load may not be available, hence the expected load curtailed is based on the curtailment agreement in place.

b) the Eskom control centre will summate the estimated total load shed and curtailed for the supply area as well as the additional generation provided and report a single load reduction number to System Operator.

4.11.2 Annual licensee performance reporting to NERSA

Licensees shall retain records of load shedding undertaken (estimated load shed at each time slot) for the purpose of reporting that may be required by NERSA. This information shall be retained for at least 5 years. This information is also required as a basis for exclusions in interruption performance reporting specified in NRS 048-6 and NRS 048-8.

NOTE NRS 048-6 and NRS 048-8 require that load shedding events be removed from interruption performance statistics when reporting.

4.11.3 General

The use of contracted demand response resources used as part of the merit order to manage load, shall not be reported as part of load shedding or curtailment.

NOTE For example, contracted interruptible loads and demand response participation (DR) customers.

4.12 Technology applications to reduce impact on customers

4.12.1 General

Several existing and emerging technologies have the potential to reduce the impact of load shedding on customers.

4.12.2 Metropolitan and municipal generation

4.12.2.1 Where a municipality or metropolitan municipality has embedded generation, and such generation is not already included in the normal load profile of the municipality, such generation may be used to reduce the load reduction required under emergencies.

4.12.2.2 Such generation may be offered as unscheduled reduction under a system constraint, particularly where the possibility of further stages of load reduction can be avoided. Where this generation has been considered as part of the load reduction required during subsequent stages, offering such generation voluntarily when called on under a system constraint should not increase the required reduction from individual municipalities or metropolitan municipalities during subsequent stages of load reduction.

NOTE Cost and resource limitations (e.g. pumped hydro schemes) might impact on the decision by a municipality or metropolitan municipality to offer this. However, this increases the likelihood that the System Operator needs to declare a Stage 1 emergency – at which stage such generation is likely to be applied in any case.

Customers with internal generation capability, but who are still taking some supply from a licensee, should be required to reduce load according to this part of NRS 048, if their generation follows a regular usage pattern.

Customers who have generation that is not normally scheduled should be allowed to generate to reduce their off take by the same amount required for load curtailment in lieu of load shedding load. If they have an agreement with the single buyer office to generate (e.g. gas turbine peaking plant) this plant cannot be used to off-set load reduction requirements.

4.12.3 Geyser control

4.12.3.1 Geyser control, where not part of the normal load profile, can be used to offset load shedding.

NOTE Where geyser control is used as a normal part of managing peak demand by a licensee, the requirement for additional load reduction during a system emergency may not be available from these systems. These may, however, be useful for emergency applications during off-peak periods.

4.12.3.2 Where geyser control is used for extended periods that overlap with periods when geyser control would normally have operated, additional load reduction is required.

4.12.3.3 Where used, geyser control should ensure that cold load pick-up does not negate the load reduction required.

4.12.3.4 The public should be informed that this is being implemented, and the regime being deployed.

4.12.3.5 Licensees should assess the scheme to assess the load reduction achieved in lieu of load shedding and report on this in accordance with the reporting requirements outlined in section 4.11.

4.12.4 Voltage reduction schemes

4.12.4.1 Voltage reduction schemes may be applied on carefully selected feeders to reduce demand during an emergency, where this is not likely to result in contraventions of the requirements of NRS 048-2.

NOTE 1 It is important to take into consideration that in residential networks, emergency load reduction is most likely to coincide with peak loading on the feeder – i.e. when the lower voltage limit specified in NRS 048-2 is at the greatest risk of being transgressed.

NOTE 2 Voltage reduction on urban networks is generally more feasible than on rural networks, which are by their nature more likely to be voltage constrained.

4.12.4.2 Where such schemes are implemented by a licensee, the licensee should provide appropriate evidence that the required load reduction is achieved.

4.12.4.3 Licensees should assess the scheme to assess the load reduction achieved in lieu of load shedding and report on this in accordance with the reporting requirements outlined in section 4.11.

4.12.5 Smart metering and load limiting schemes

4.12.5.1 Smart meters and intelligent load limiting schemes may be deployed as a technology solution to limit the impact on customers, whilst still providing a load reduction under a system emergency.

NOTE 1 The implementation of smart metering and load limiting schemes allows greater flexibility in protecting critical loads from load shedding on a given circuit (i.e. allowing these to remain connected, whilst other customer loads on the same circuit are interrupted or curtailed).

NOTE 2 The implementation of smart metering and load limiting schemes allows individual customers to maintain supply to limited appliances (e.g. lighting, computers, televisions, wifi routers etc.)

NOTE 3 Emergency load reduction may be achieved through facilities such as load limiting (setting a dynamic current threshold) and appliance control (direct switching of appliances such as pool pumps).

4.12.5.2 Where the equivalent reduction can be demonstrated, smart metering and load limiting schemes may be used by licensees to off-set their load shedding requirements under Stages 1 to 4, as well as under extreme system constraints (Stages 5 to 8).

74.

4.12.5.3 Load limiting or load switching may be implemented to achieve curtailment in accordance with the required stages (percentages) of load curtailment in Table 1.

4.12.5.4 Load limiting or load switching may be implemented to achieve the equivalent of rotational load shedding on a rotational basis in accordance with the required stages of load shedding (Table 1).

4.12.5.5 In both 4.12.5.3 and 4.12.5.4 the following shall apply

a) the notification period should be restricted to a maximum of 15 minutes;
b) the licensee should adjust the current limit threshold or have the loads switched to achieve the required load reduction; and
c) customers shall be treated equitably.

NOTE The current limit is likely to be much smaller where smart meters are used to provide the equivalent of rotational load shedding.

4.12.6 Feeders with embedded generation

Feeders with embedded generation should be addressed on a case-by case basis, whilst ensuring that the required demand reduction is met. Where there is uncertainty, the System Operator should be consulted to determine the adequacy of the reduction regime.

NOTE Examples include Cooperation between customers and generators on the feeder to ensure that the feeder demand requirement meets the equivalent load shedding requirement (e.g. customers reduce demand over the two hour period), and/or the implementation of smart meters.

5. Extreme supply constraint (Contingency planning)

5.1 General

5.1.1 The System Operator is responsible for developing, maintaining, and testing plans for an extreme power system constraint. Such a constraint may require load reduction beyond that provided by Stage 4 schedules and curtailment.

5.1.2 Licensees shall develop emergency load reduction protocols and schedules that support the plans for an extreme supply constraint, as indicated in this section.

NOTE The Disaster Management Act No.57 of 2002 requires plans to be in place to manage all identified electricity related disasters, including those with a low likelihood of occurrence. An extreme supply constraint is one such disaster scenario. In order to ensure adequate preparedness for such a scenario, licensees are required to prepare contingency schedules in accordance with this section of the code of practice.

5.1.3 Where practicable, an extreme supply constraint shall be managed in terms of the measures and associated priorities indicated in. The System Operator may however at any time at its discretion implement alternative interventions, should these become necessary.

Table 4 — Mechanisms and associated priorities for responding to an extreme supply constraint (beyond Stages 1 to 4).

1	2	3
National power system load reduction required	**Mechanisms**	**Priorities**
Approximately 1000MW to 4000MW	(a) Load shedding in terms of published schedules Stages 1-4 (b) Load curtailment (Stages 1&2 10%, Stage 3 15%, Stage 4 20%) (c) Load reduction via limiting and load switching (Smart Meters) (NOTE See Table 1)	(a) Controlled, manual, mandatory load reduction implemented by control rooms and customers under instruction by the System Operator. (b) Minimised impact on customers through limiting the load curtailment requirement and the duration of load shedding time slots. (c) Pre-published schedules in place to provide predictability. (d) Critical loads managed through schedules and associated protocols.
Approximately 4000MW to 8000MW	(a) Contingency schedules Stages 5-8 (b) Load curtailment down to essential load requirements as instructed by the System Operator (either all customers or on a rotational basis) (c) Load reduction via limiting and load switching (Smart Meters) (NOTE See Section 5)	(a) Controlled, manual, mandatory load reduction implemented by control rooms and customers under instruction by the System Operator. (b) Limiting potentially large system frequency variations. (c) Limiting the extended operational impact of load reduction on distribution licensees. (d) Supply to essential loads (as far as is practicable) (e) Critical loads managed where possible through schedules and associated protocols. Customer contingency planning essential. (f) Contingency schedules in place and made available should these be required.
Beyond 8000MW	As instructed by the System Operator	(a) Managing system frequency. (b) As far as possible, maintaining an integrated power system, but pre-emptive islanding if necessary. (c) Open transmission lines to control voltages. (b) Maintaining generation to initiate system restoration after the constraint.
NOTE The System Operator will generally instruct licensees and curtailment customers to implement load reduction as required. In exceptional cases and/or when a rapid response is required, the System Operator will intervene directly by interrupting bulk supply to specific areas.		

5.2 Contingency schedules for extended load shedding

5.2.1 Minimum requirements for contingency schedules

Contingency load shedding schedules shall comply with the following minimum requirements.

a) **transition from Stage 4**: Schedules beyond Stage 4 shall be implemented so as to facilitate a smooth transition from Stage 4; and

b) **magnitude of the load switched**: The load switched out at any transition from one time slot to another shall not be larger than the blocks of load being shed under Stage 4.

NOTE The approach adopted in responding to an extreme supply constraint is to limit the complexity and magnitude of load reduction beyond Stage 4, manage critical and essential load requirements, as well as to ensure a smooth transition from Stage 4 shedding to subsequent extreme stages. This is necessary given control system limitations, operational limitations, and the impact on system frequency variations of increased load switching.

5.2.2 Design of contingency load shedding schedules

In the absence of any other approach approved in writing by the System Operator, contingency schedules for extended load shedding shall be based on the Stage 1 to 4 schedules in accordance with the minimum requirements in 5.2.1 and the design parameters defined Annex J.

5.2.3 Execution of contingency load shedding schedules

Licensees shall execute the schedules as instructed by the System Operator.

The System Operator may instruct staggered implementation of the schedules as these are initiated and in the transition to the following block of load during load rotation (see NOTE 1 and 2). Licensees shall ensure that control and field staff is adequately trained to implement such staggered schedules.

NOTE 1 The System Operator may instruct some areas of the country to execute these earlier that others in order to manage the impact on system frequency – typically over a period of 30 min.

NOTE 2 The System Operator's priority of managing system frequency under a severe system constraint exceeds the priority for schedules to be accurately adhered to. Under a severe system constraint system frequency may be impacted more than under normal conditions due to (i) the larger load returned to the system when a block of load is restored and (ii) the smaller frequency bias of the system when it is serving less demand (i.e. a smaller change in load or generation gives rise to bigger variation in frequency).

5.2.4 Extended load curtailment

An instruction may be issued by the System Operator for curtailment customers to reduce their load to the pre-determined essential load requirement. This instruction may be issued to all customers simultaneously or may be instructed on a rotational basis. The notification period shall, where practicable, take into consideration the safety and environmental implications on the customer installation.

NOTE Example: A 6 hour period may be required to evacuate some deep level mines.

The instruction for curtailment customers to curtail beyond Stage 4 should, where practicable, not be implemented for more than 24 hrs without extended load shedding schedules being invoked.

5.2.5 Extended load limiting and appliance switching

Load limiting may be instructed through instructing a deeper limit or increasing the duration of the reduction.

5.3 Load reduction beyond the contingency schedules

The system operator will instruct load reduction or undertake switching to reduce demand as required, should this be required. Licensees shall respond as instructed.

6. Blackout restoration

6.1 General

6.1.1 The System Operator is responsible for developing, maintaining, and testing plans for restoring supply after a national or regional blackout.

6.1.2 Licensees shall to support the System Operator in developing restoration plans that support the national and regional restoration plans.

6.1.3 Restoration plans should as far as possible take essential load requirements into consideration, once the system is adequately stable.

NOTE 1 It should be noted that stabilization of the power system will generally take precedence over restoring supply to specific customers (including essential loads).

NOTE 2 The National Disaster Management Centre and the Provincial Disaster Management Centres are responsible for overseeing the development of multi-sectoral plans for a country response to a national or regional blackout. Licensees are required in terms of the Act to engage with the disaster management structures to develop coordinated plans.

6.2 Licensee responsibilities

6.2.1 Licensees are responsible for developing, maintaining and testing plans for restoring supply after a regional or local blackout. These plans should be reviewed annually. The plans should take the essential load requirements of clause 6 into consideration.

6.2.2 Licensees are responsible for ensuring that their management plans for restoring supply after a blackout are incorporated in the national and provincial multi-sectoral plans to respond to a blackout.

6.2.3 A customer's supply may be cut off if that customer exceeds the notified essential load data during the restoration process.

6.3 Customer responsibilities

6.3.1 Customers should provide their suppliers (licensees) with information on essential load requirements in terms of the requirements in clause 6.

6.3.2 Customers may also be required to cooperate in the case of exercises related to blackout preparedness.

7. Essential load requirements

7.1 General

7.1.1 A register of essential loads is required by a licensee for the prioritization of restoration of supply in the case of a major system incident or blackout. Customers are required to provide the necessary information to ensure that they are prioritized for restoration after a major system incident or blackout.

7.1.2 The essential load requirement agreed in writing with the licensee is also the maximum customer load that will be supplied should load reduction be implemented under an extreme supply constraint (see section 5), and where this is practicable.

7.1.3 An essential load requirement agreed with the licensee can generally be met during load reduction emergency (Stages 1 – 4 as well as under extreme conditions up to Stage 8) by a licensee where customers meet the requirements of a curtailment customer. Where this is not the case, such essential load requirements may not be possible to be supplied unless interventions are agreed with the licensee.

7.2 Application by licensees

7.2.1 Licensees are required to collect essential load data and to appropriately address customer essential load requirements. Licensees should notify customers at least every two years that such information is required.

7.2.2 A licensee should provide its upstream licensee with the power supply requirements to comply with its essential load requirements (i.e. its own essential loads and that of its customers). Annex E provides the format for such submissions.

7.2.3 In the absence of a submission from a licensee, the maximum power requirement associated with essential load allocated to a licensee should be 20 % of the notified maximum demand. A licensee should evaluate its essential power requirements, and where these are greater than this amount, this will need to be justified based on

a) individual essential load requirements from its customers; and

b) essential load requirements in its area of supply (see Annex E for municipal and metropolitan municipality submissions).

7.2.4 Clarification of the requirements should be undertaken, where required. The upstream licensee should notify the licensee of the agreed essential load requirement.

7.2.5 A licensee cannot guarantee that essential load requirements can be met under supply emergencies.

7.3 Application by customers

7.3.1 Customers should notify their licensee of their essential load requirements. Such requirements should be regularly updated (at least every two years) by the customer to reflect any changes to processes or requirements (or both) with regard to safety or the environment.

7.3.2 Where a customer does not provide an essential load requirement, the licensee should be entitled to assume that no such requirement exists.

7.3.3 It is incumbent on a customer to ensure that appropriate measures are taken in the case of an interruption of the supply of electricity to an essential load.

7.4 Identification of essential load requirements

7.4.1 Essential loads are identified by customers within their own business environment. Customers should inform their supply authority of their essential load requirements by completing and submitting standard forms designed for this purpose (see Annex B). The relevant supply authority should collate such information and compile a registry of essential load requirements within his area of supply.

7.4.2 The essential load requirements may be subject to verification by the licensee in terms of the following criteria:

a) critical safety;
b) critical environment impact; and
c) critical national product.

7.4.3 Where the submission does not comply with these verification requirements, the licensee should inform the customer.

7.4.4 Customers with essential load requirements should ensure that appropriate backup systems are in place, as restoration times cannot be guaranteed for the various possible system emergencies that could occur.

7.4.5 Where customers meet the requirement for curtailment, essential loads may be catered for under the load not curtailed. Where essential loads are embedded in networks that are shed, protection against load shedding may not be possible.

7.5 Identification of loads with essential load requirements

All customers in the following categories should be required to provide essential load details:

a) deep level mines;
b) hospitals and medical centres with life-support requirements;
c) sewerage systems;
d) prisons;
e) refineries;
f) national key points reliant on electricity for their core operations; and

g) potable water systems.

NOTE In the case of some customers' processes, the essential load requirement might belong to another customer who is providing an essential service or product.

8. Critical loads

8.1 General

Critical loads are loads that are critical for maintaining the operational integrity of the power system, or for avoiding a cascading impact on public infrastructure in the event of a system emergency. Critical loads should as far as possible be protected from the impact of load shedding or loss of supply. Protection measures could include the exclusion from load shedding schedules, installing of backup facilities, or implementing of specific protocols for interaction between the customer and the licensee. This section addresses the specific interventions associated with identified critical loads.

8.2 Application by licensees

8.2.1 Licensees are required to appropriately interact with customers in addressing critical loads as defined in 8.4 to 8.6.

8.2.2 Licensees should identify the feeders to which these critical loads are connected.

8.2.3 Licensees who choose to be shed completely by an upstream licensee should ensure that the critical load requirements are addressed or that alternative arrangements have been agreed with customers operating affected critical loads. Information related to such arrangements should be made available to the upstream licensee should this be requested. Provision of such information should not constitute a change in responsibility of the licensee to address the requirements of the critical load, or that alternative arrangements have been agreed.

8.3 Application by customers

8.3.1 Customers who operate critical loads should evaluate their level of preparedness and protection of their facilities in terms of the practices in this part of NRS 048.

NOTE A licensee cannot guarantee that the requirements can be met under all supply emergencies and it is incumbent on the customer to take appropriate measures to protect their installations in such cases.

8.3.2 All customers are entitled to apply to a licensee for critical load status. Such status should be determined by the licensee in accordance with the requirements set out in this section.

8.4 Treatment of critical loads

8.4.1 Specific critical loads are identified in clause 8.6, together with the required treatment of these

8.4.2 In the case of critical loads not identified in this part of NRS 048, licensees and customers should cooperate in addressing the requirements of these loads by considering at least the following alternatives:

a) exclusion from load shedding schedules and curtailment requirements. This should, in principle, be limited to cases where the load can be isolated so that other loads that should be shed are not also protected from the load shedding schedules. Critical loads that must be excluded but cause unavoidable loads to be likewise excluded should be accommodated through design of the schedules (through shedding other load to accommodate this).

   NOTE Exclusion from load shedding is possible where the customer load is supplied direct (not one of several loads on a given feeder), or where smart metering or load limiting technologies have been installed on all loads on the feeder.

b) whether the installation complies with the conditions for load curtailment as described in clause 4, and is not severely impacted by such curtailment;

c) if shedding is required, the specific time of day that these loads are shed (i.e. times when the impact of shedding these loads might not be so severe);

d) interventions within the installation (e.g. appropriate backup supplies); and

NOTE In the case of many critical loads, such intervention might be necessary in any case to protect the installation in the event of a supply interruption due to a local network outage.

e) protocols for interaction between the customers who operate critical loads and the electricity supply utility

NOTE 1 For example, provision of a direct line of communication to a regional or municipal/metropolitan department designated to assist such cases in the event that the on-site backup supply fails.

NOTE 2 Care needs to be taken to limit pre-calling and emergency switch-back to "critically important" critical loads under extreme conditions.

8.4.3 Where a customer considers an installation that is not listed in this section to be a critical load, the supplier may be engaged to consider the implementation of specific interventions. Where these include exclusion from the load shedding schedules, a customer should seek approval from NERSA to be listed as a critical load. In determining the critical load status, NERSA should consider representation of the licensee in this regard.

8.5 National key points

National key points other than those identified as critical loads and that are reliant on electricity for their core operations should be included in load shedding schedules, with the exception of the Union Buildings and the National Parliament. National key points need to provide essential load requirements in terms of the provisions of 7.3.

8.6 Requirements for specific types of critical loads

8.6.1 General

The requirements for specific types of critical loads are summarized in Table 5 and addressed in detail in 8.6.2 to 8.6.18.

b) whether the installation complies with the conditions for load curtailment as described in clause 4, and is not severely impacted by such curtailment;

c) if shedding is required, the specific time of day that these loads are shed (i.e. times when the impact of shedding these loads might not be so severe);

d) interventions within the installation (e.g. appropriate backup supplies); and

NOTE In the case of many critical loads, such intervention might be necessary in any case to protect the installation in the event of a supply interruption due to a local network outage.

e) protocols for interaction between the customers who operate critical loads and the electricity supply utility

NOTE 1 For example, provision of a direct line of communication to a regional or municipal/metropolitan department designated to assist such cases in the event that the on-site backup supply fails.

NOTE 2 Care needs to be taken to limit pre-calling and emergency switch-back to "critically important" critical loads under extreme conditions.

8.4.3 Where a customer considers an installation that is not listed in this section to be a critical load, the supplier may be engaged to consider the implementation of specific interventions. Where these include exclusion from the load shedding schedules, a customer should seek approval from NERSA to be listed as a critical load. In determining the critical load status, NERSA should consider representation of the licensee in this regard.

8.5 National key points

National key points other than those identified as critical loads and that are reliant on electricity for their core operations should be included in load shedding schedules, with the exception of the Union Buildings and the National Parliament. National key points need to provide essential load requirements in terms of the provisions of 7.3.

8.6 Requirements for specific types of critical loads

8.6.1 General

The requirements for specific types of critical loads are summarized in Table 5 and addressed in detail in 8.6.2 to 8.6.18.

Table 5 — Summary of how critical loads are required to be addressed

1	2	4	5
Load	**Scheduled for load shedding**	**Protocols before / during shedding**	**Comment**
Airports	Yes	Yes / Yes	Airports require on-site backup supplies as a legal requirement
Rail (Commuter)	No	None	Where the power supply system allows for this
Rail (Long distance)	Yes	None	May be treated as curtailment loads where practicable
Traffic lights	Yes	None	The treatment of high, medium, and low impact traffic lights is addressed
Water (Power stations)	No	None	
Water (Industrial)	Yes	None	
Water (Agricultural)	Yes	None	May be temporarily removed if a state of disaster is declared.
Water (Potable)	No*	None	* Bulk supply systems
Stadiums	Yes	No	May be temporarily removed in the event of a major event
Sewage	Yes*	None	* Unless the impact cannot be addressed
Refineries	No	None	May be treated as curtailment loads
Fuel pipe lines	No	None	
Coal mines	No*	None	* Only those mines that supply power stations
Education	Yes*	None	* Special arrangements may be made for temporary removal at critical times
Police	Yes	None	Adequate backup systems must be in place
Telecom's	Yes*	None	* See requirements related to data centres
Hospitals	Yes	Yes/Yes	
Clinics	Yes	None	
Data centers (National footprint)	Yes	Yes*	* Hotline for customers should backup systems fail
Ports authorities	Yes	None	
Government Buildings	Yes*	None	* With the exception of the Union Buildings and National Parliament
Electricity Control Centres	No	N/A*	* Control centres are notified by default of load shedding as part of the load shedding process
NOTE National key points in general are not by default considered critical loads. Application for temporary or permanent exemption needs to be made in terms of the criteria for critical loads.			

Where these installations are not excluded from load shedding, functional requirements are specified for protecting these installations. Technology choices, however, are not specified and the most appropriate option is to determine by the relevant stakeholder.

8.6.2 Airports

8.6.2.1 Airports should be required to participate in emergency load shedding or curtailment.

8.6.2.2 The licensee control centre that manages the emergency load reduction of the airport should provide the airport with direct communication and cooperation to the control room in the case of an emergency (e.g. the failure of backup generators).

8.6.2.3 Protocols should be in place for notifying these customers that load shedding has commenced, so as to allow them to start up the backup generators, if required.

8.6.2.4 Airports should ensure that on-site backup supplies should be available for critical processes.

NOTE Secondary power supplies, independent of the public power supply should be provided in accordance with the standards and recommendations of the Convention on International Civil Aviation, as adopted or adapted by the Civil Aviation Authority of South Africa.

8.6.3 Rail

8.6.3.1 Category 1 – Commuter rail systems

Commuter rail systems should be excluded from schedules and load curtailment requirements, where the network configuration allows.

NOTE Long distance passenger rail systems are not considered.

8.6.3.2 Category 2 – Long distance rail systems

Long distance rail systems are not excluded from load shedding unless the operators of such systems can engage with the relevant licensee(s) to be treated as curtailment customers

8.6.4 Traffic lights

8.6.4.1 General

The electricity supply infrastructure to traffic lights might not allow for isolation from other loads in the event of load shedding.

NOTE All traffic light installations should be fitted with reflective indicators in the event of an interruption in supply during the night.

8.6.4.2 Category 1 – High impact intersections

High impact intersections are defined as those that would lead to significant congestion on major highways, in central business districts, or important access points (e.g. roads to airports).

One of the following treatment methods is recommended:

a) backup systems able to support the supply for at least 4 h; or alternatively; and
b) effective deployment of points men should be planned.

NOTE Theft of components of the backup systems is a concern.

8.6.4.3 Category 2 – Medium impact intersections

Contingency plans should be implemented at medium impact intersections to ensure that traffic flow is maintained. Plans could include the co-ordinated deployment of point men or traffic officials, based on the schedules.

8.6.4.4 Category 3 – Low impact intersections

No specific interventions are required at low impact intersections.

8.6.5 Water

8.6.5.1 Supply to power stations

Water supply systems to power stations (including co-generators) should be excluded from load reduction requirements.

8.6.5.2 Industrial water

Water supply systems to industrial plants should be addressed under essential load requirements.

Users should have adequate contingency plans in place to allow for a disruption of water supply.

8.6.5.3. Agricultural water schemes

Water supply systems to agricultural areas shall in principle be included in load shedding.

In periods of drought, declaration of a disaster in terms of the Disaster Management Act may allow exclusion from the schedules for the duration of the declared disaster, subject to the need for this being clearly identified.

8.6.5.4 Reticulated potable water supply

8.6.5.4.1 Potable water is a national critical product and the power supplies required to supply potable water should be treated in terms of the requirements in this clause.

8.6.5.4.2 Operators of potable water systems should assist with load curtailment when they can.

NOTE 1 Under extreme heat conditions when the demand for potable water is high, load curtailment might not be possible.

Load curtailment under emergencies should be undertaken by considering the specific impact and technology being used by the public water system (for example, pumping versus gravity fed systems).

NOTE 2 Restoration of water supply can take several hours after an interruption in electricity supply due to factors such as

a) the time taken to fill reservoirs; and
b) the treatment process utilized (load needs to be increased slowly to ensure good quality of the water).

8.6.5.4.3 Licensees that supply public water systems should take adequate measures to ensure that these systems are addressed in terms of the provisions set out in 8.6.5.2.4 to 8.6.5.2.6.

8.6.5.4.4 Should a licensee choose not to curtail but to refer this curtailment to a higher voltage level (i.e. the upstream supplier), the former licensee should still be responsible for ensuring that the critical load requirement is considered.

8.6.5.4.5 Typically the provisions set out in Table 6 could apply for major public potable water distribution systems, where such major systems meet curtailment requirements.

Table 6 — Typical provisions for major potable water distribution systems

1	2	3
Provision	**Stages 1 and 2**	**Stages 3 and 4**
Notice period	4 h to 5 h	4 h to 5 h
Curtailment	10 % to 15 %	15 % to 20 %
Duration	3 h to 4 h	3 h to 4 h

TA

NOTE 1 Such systems will not save energy, in that the energy used is proportional to the quantity of water pumped. Shedding these systems will therefore only result in a load reduction at the time. Significant energy will be used to make up the water demand and therefore consideration of the specific type of emergency might be required (i.e. if the expected duration of the emergency is more than 2 h in 72 h, load curtailment from these systems will in general not be appropriate).

NOTE 2 Public potable water systems have extensive hydraulic networks. Interrupting the electrical supply to these systems will result in pressure surges which can endanger the health and safety of the public.

NOTE 3 Public potable water systems consist of hydraulic networks and gravity distribution networks. Interrupting the electrical supply to these systems for an extensive period will result in the ingress of air into the hydraulic system. The removal of air from these systems can take days during which the operators of potable water systems will not be able to supply potable water to the public.

8.6.5.4.6 Licensees should engage with water suppliers and other licensees where water systems cross supply boundaries to minimize the impact of shedding on these systems.

8.6.6 Sports stadiums

8.6.6.1 Sports stadiums should be required to participate in emergency load shedding or curtailment.

8.6.6.2 Stadiums should ensure that on-site backup supplies should be available for critical processes.

8.6.6.3 The licensee control centre that manages the emergency load reduction of the stadium should provide the stadium with direct access to the control room in the case of an emergency (e.g. the failure of backup generators). Where the licensee is notified of a major sporting event, protocols should be agreed upon for notifying these customers that load shedding has commenced – so as to allow them to start up the backup generators.

8.6.6.4 In the case of major sports events, the requirements in section 4.8.6 may be applied.

8.6.7 Sewerage

Generally sewerage systems should be included in load shedding schedules. Special attention should be given to identify linked pump stations and to co-ordinate load shedding to ensure that shedding will not result in adverse environmental consequences. Where this is not possible, these systems may be removed from load shedding schedules.

8.6.8 Refineries and fuel pipe lines

Refineries, fuel pipe lines, and associated loading and off-loading depots should be excluded from emergency load reduction requirements.

NOTE Current refinery and pumping capacity is limited in the country.

8.6.9 Mines that supply power stations

Coal mines that supply power stations (including co-generation plant) should be excluded from load shedding schedules.

8.6.10 Educational facilities

Educational facilities should be included in load shedding schedules.

NOTE 1 These facilities are generally within communities and would result in significant sections of load not being shed to maintain supply to these installations.

NOTE 2 It is possible that arrangements may be made to limit the impact of load shedding on educational facilities at critical times of the academic year through consultation between government and NERSA. This may entail pre-planning on the system and the use of only curtailment loads whether the system constraint can still be managed.

8.6.11 Electricity control centres

Electricity control centres may be excluded from load shedding schedules.

NOTE These will by default be informed of load shedding as part of the load shedding process.

8.6.12. Ports authorities

Ports authorities should be included in load shedding schedules.

8.6.13 Essential services

Police, fire fighting, and other essential services should be included in load shedding schedules. These customers should provide their own backup facilities.

Processes should be in place to provide fire fighting services with information when load shedding has commenced. In the event of a fire, these services should liaise directly with the control centre or appropriate liaison mechanism provided for in advance by the licensee.

NOTE These facilities are generally within communities and would result in significant sections of load not being shed to maintain supply to these installations.

8.6.14 Telecommunications infrastructure

The facilities of telecommunication service providers should be included in load shedding schedules. These customers should provide their own backup facilities and contingency plans.

NOTE 1 These facilities are generally within communities and would result in significant sections of load not being shed to maintain supply to these installations.

NOTE 2 The need for contingency plans and backup applies in particular to electricity control room to control room communication.

8.6.15 Hospitals and medical centres

8.6.15.1 General

8.6.15.1.1 Hospitals and medical centres should be included in load shedding schedules.

8.6.15.1.2 State and private hospitals should be treated equally.

8.6.15.2 Category 1 – Hospitals with life-support systems

8.6.15.2.1 These hospitals should provide their own backup facilities.

8.6.15.2.2 Protocols should be in place for hospitals to contact the local operations centre directly in the event of an emergency, for example, if the backup facility is out of service at the time of load shedding.

8.6.15.2.3 Protocols should be in place for notifying these customers that load shedding has commenced – so as to allow them to start up the backup generators.

8.6.15.3 Category 2 – Hospitals without life-support systems

8.6.15.3.1 Hospitals should, if practicable, provide their own backup facilities.

14

8.6.15.3.2 Protocols should be in place for hospitals to contact the local operations centre directly in the event of an emergency.

8.6.15.3.3 Protocols should be in place for notifying these customers that load shedding has commenced – so as to allow them to start up the backup generators.

8.6.15.4 Category 3 – Clinics and medical centres

Clinics and medical centres are not classified as critical loads.

8.6.16 Public health and safety

8.6.16.1 Category 1 – Danger to life and safety

8.6.16.1.1 All officers in charge of public buildings and facilities should be required to assess the risks to the public associated with power interruptions, implement appropriate back-up supplies and declare their essential load requirements.

NOTE Declaration of essential load requirements is for the purpose of restoration after a blackout / interruption.

8.6.16.1.2 By exception such buildings or facilities may be considered as critical loads.

8.6.16.2 Category 2 – Environmental or health hazard

8.6.16.2.1 All officers in charge of public buildings and facilities should be required to assess the risks to the public associated with power interruptions and declare their essential load requirements.

8.6.16.2.2 By exception such buildings or facilities may be considered as critical loads.

8.6.17 Data centres

8.6.17.1 General

8.6.17.1.1 Data centres should be included in load shedding schedules.

8.6.17.2 Data centres supplying critical national infrastructure

8.6.17.2.1 Data centres supplying critical national infrastructure should provide their own backup facilities.

8.6.17.2.2 Protocols should be in place for these customers to contact the local control centre directly in the event of an emergency, for example, if the backup facility is out of service at the time of load shedding.

NOTE 1 In this context, critical national infrastructure includes the supply of water, electricity, telecommunications, and financial services.

NOTE 2 Implementation of these protocols should be limited to exceptional circumstances beyond the ability of the customer to have reasonably foreseen or to have provided for.

8.6.18 National critical product

Where the destruction or damage to plant, equipment, or facilities would disrupt production of a nationally critical product, the minimum power required to prevent such damage may be considered as an essential load requirement.

NERSA shall in any dispute rule on the nature of a product being considered a national critical product.

NOTE Examples include water, petroleum.

9. Technical consderations when developing schedules

9.1 General

Practical systems limitations and the impact of load shedding on plant operated by both licensees and customers need to be considered when load reduction protocols are being developed.

9.2 Supervisory versus manual control

Many municipalities and some metropolitan municipalities require the manual switching of circuits. This may impact on the ability to switch at feeder level. In such cases it might be prudent or necessary to switch at a point further back in the network.

9.3 Cold restoration considerations

Care needs to be taken when returning load after it has been shed. The cold load pick up may be significantly higher than normal full load, placing the system under renewed stress. This is really a problem in municipalities, because they often do not have the means to limit the load after power restoration.

NOTE One of the motivations for continuing to operate and extend "ripple control" systems is their ability to limit and control the pick-up load.

10. Roles and responsibilities

10.1 NERSA

NERSA will ensure the implementation of this code of practice by licensees through:

a) instructing licensees on what elements of this code are to be implemented;

b) implement audits as and when necessary to ensure that the relevant requirements of this code are implemented; and

c) an appropriate reporting system to ensure that licensees have implemented the requirements.

NERSA will, with regard to variations or exemptions form this code:

a) consider and approve (or otherwise) any application by a licensee or customer for a variation or exemption from the requirements of this document.

b) when considering such applications, consult the affected licensees and the System Operator on the impact of such variations or exemption on the power system

c) publish a list of sites approved for exclusion from the schedules, including those that are approved for exclusion on application from a licensee or customer

10.2 System operator

The System Operator is empowered in terms of the Grid Code to implement any intervention it deems necessary to ensure the stability of the power system. Where conditions at the time allow, the System Operator shall instruct distribution licensees (or their agents) to implement load reduction in terms of this part of NRS 048.

10.3 Distribution licensees

Distribution licensees shall implement load reduction as instructed by the System Operator. This implementation shall be in terms of the requirements of this part of NRS 048.

Annex A – Ensuring the integrity of the under-frequency load shedding scheme when developing manual load shedding schedules

(informative)

A.1 Under-frequency load shedding

The national under-frequency load shedding (UFLS) scheme is designed to ensure that the system responds immediately to a frequency drop caused by a sudden and significant imbalance between available generation capacity and demand. The response required is for load to be shed immediately to prevent a cascading loss of generation units due to low frequency. This is done by the automatic removal of pre-defined loads from the system by means of under-frequency protection relays. This type of under-frequency protection is typically required when a single system event results in multiple generation units being removed from the system (e.g. a fault in the transmission yard of a large power station).

The UFLS scheme is addressed by the Grid Code – and as such is not specified in this part of NRS 048.

A.2 Emergency load reduction (shedding and curtailment)

Emergency load shedding and curtailment as specified in this part of NRS 048 relates to the pro-active, manual reduction in demand by the System Operator where it becomes clear that insufficient generation resources are available to serve the prevailing or expected load.

A.3 Stages of emergency load reduction (shedding and curtailment)

The UFLS scheme makes use of several stages of automatic load shedding. These stages are not related to the stages of mandatory load shedding specified in this part of NRS 048.

A key requirement of this part of NRS 048 however, is that where emergency load reduction schedules are built, these are built in such a manner that the under-frequency load shedding (UFLS) scheme is not materially compromised (i.e. that loads shed or curtailed under emergency load reduction are not those also required for the automatic protection system to respond to a significant incident involving loss of generation on the system).

A.4 Development of load shedding schedules considering UFLS

The development of load shedding schedules needs to address integrity of the under-frequency load shedding scheme. Schedules that address this requirement will provide the system operator with significantly enhanced capability to manage system constraints – i.e. controlled, manual load reduction can be safely implemented without placing the system at increased risk should an incident occur that requires load to be automatically shed.

NOTE In January 2008 a general system emergency was declared due to concerns about the security of the power system being compromised. This code, through addressing the integrity of the under-frequency protection system, ensures a much more robust regime for managing a system constraint.

A.5 Example of the calculation of schedules taking automatic under-frequency load shedding (UFLS) into consideration

Table E.1 is an example of how the integrity of the under-frequency scheme is maintained through careful allocation of loads to the scheduled time slots. In theory, if the UFLS loads are perfectly spread among the load shedding blocks then load shedding, if perfect, will reduce the instantaneous demand by the exact amount that the loss of the UFLS load would have required for compliance. Since a perfect spread is not possible, the utility will have to evaluate the gap from the analysis as per table E.1, provide the additional UFLS load and inform the System Operator of the extra amount now likely to be shed in the case of a UFLS event taking place outside of load shedding.

Annex A
(concluded)

The example in table A.1 assumes the following:

a) A schedule of eight 3 h time slots, with a 200 MW reduction required per time slot; and
b) UFLS stage 3 loads totalling 160 MW(10% of the peak demand) (see total in column 3)

Because of the percentage gap seen in column 6, additional UFLS is added in column 7 to achieve 100 % of the UFLS requirement under the load shedding condition. The increased amount is what is required to fill the largest gap in the UFLS coverage (5 MWs), which must be scheduled at other times, with no other time being having more UFLS scheduled than the previous largest amount (25 MWs).

Table A.1 — Example of the calculation of schedules taking UFLS into consideration

	1	2	3	4	5	6	7	8
3 h time slot	Load base	Manual load shedding (MW)	UFLS CVA required before LS	UFLS CVA required after LS	UFLS lost in LS stage	UFLS % available	UFLS lost in LS stage	UFLS % available
00:00-03:00	1600	200	160	140	17	102%	17	102%
03:00-06:00	1600	200	160	140	15	104%	15	104%
06:00-09:00	1600	200	160	140	25	96%	25	100%
09:00-12:00	1600	200	160	140	15	104%	15	107%
12:00-15:00	1600	200	160	140	25	96%	25	100%
15:00-18:00	1600	200	160	140	18	101%	18	105%
18:00-21:00	1600	200	160	140	22	99%	25	102%
21:00-24:00	1600	200	160	140	23	98%	25	101%
Total	NA	1600	NA	NA	160	NA	165	NA

Annex B – Essential load data for system restoration planning and load shedding – Model forms for information required from customers (end users)

(normative)

B.1 Model form for information on essential loads in the case of a network collapse and restoration

Form B.1

ESSENTIAL LOADS IN THE CASE OF NETWORK COLLAPSE AND RESTORATION

- Details regarding requirements for the return of electrical power supply and the priority of restoration after a national or regional large-scale network collapse are to be recorded in this form.
- Typically, there would be a total loss of power and the details submitted are required to determine the duration before power is returned to the customer's site and the extent of power that should be returned.
- All production would be shut down, and minimal power will be made available for the purposes of
  - a) avoiding danger to the lives and safety of persons,
  - b) avoiding a potential hazardous condition from developing,
  - c) shutting plant down safely.
- No provision should be made to continue with normal or reduced production until after the emergency has been concluded.

CATEGORY A1: THE RETURN OF POWER TO PREVENT DANGER TO LIVES AND FOR SAFETY

Maximum permissible duration of power interruption before dangerous conditions develop *(Explanation: the amount of time before conditions become life threatening)*	**Survival load required once power has been returned after the above interruption** *(Explanation: the amount of load required to effectively remove personnel or prevent a dangerous condition from developing.)* *(Not intended for continuous use, but for the purposes of a controlled and safe shutdown, evacuation, etc.)*	**Details of plant, equipment, facilities which will be operated by the power detailed herein.** *(For example, winders, vent fans, dewatering pumps.)*	
HOURS	**MVA**	**Please describe plant in the space below**	**General comments**

Annex B
(continued)

CATEGORY A2: THE RETURN OF POWER TO PREVENT A POTENTIAL ENVIRONMENTAL OR HEALTH HAZARD			
Maximum permissible duration of power interruption before a potential hazard develops *(Explanation: length of time before an outage (complete interruption)* ***causes damage to a resource or results in legislated limits e. g. environmental or occupational hygiene limits)*** (see foreword) ***to be exceeded.***	**Survival load required once power has been returned after the above interruption** *(Explanation: the amount of load needed to bring the limits back to acceptable levels. If the load needs to be continuous, please indicate this)* *(Not intended for continuous use, but for purposes of a controlled and safe shutdown, if possible.)*	**Details of plant, equipment, facilities which will be operated by the power detailed herein.** *(For example, dust control plants, oil water separation units, sewer pumps.)*	
HOURS	**MVA**	**Please describe in the space below**	**General comments How is it required?**

CATEGORY A3: THE RETURN OF POWER TO PREVENT THE DESTRUCTION OF OR DAMAGE TO PLANT, EQUIPMENT OR FACILITIES WHICH WOULD DISRUPT PRODUCTION OF A NATIONALLY CRITICAL PRODUCT			
Maximum permissible duration of power interruption before damage or destruction occurs *(Explanation: the amount of time before plant, equipment, facilities will incur damage. This applies only to plant, equipment or facilities and not to the product itself. If the plant, equipment, facility, will be instantly damaged or incur irreversible damage, please describe in field provided.)*	**Survival load required** *(Explanation: the amount of power, following an interruption which will be needed to prevent damage to the plant, equipment, facility. This may imply the need for continuous load but ideally should be the amount of load needed to ramp down the plant, facility, in a non-damaging way. Please describe the load (continuous or ramp-down) in the field provided.)*	**Details of plant, equipment, facilities, which will be operated by the power detailed herein.** *(For example smelters, silting of pipelines, freezing of charge or chutes.)*	
HOURS	**MVA**	**Please describe in the space below**	***If the plant, equipment, facility will be instantly damaged or incur irreversible damage, please describe in field below*** **General comments**

SUMMARY FOR ALL THREE " A " CATEGORIES		
Category	Time (hours)	Survival load (MVA)
A1		
A2		
A3		
TOTAL		
NOTE Categories A1, A2, and A3 should be mutually exclusive of one another.		

Annex B
(continued)

B.2 Model form for information required in the case of continuous load reduction (load shedding or curtailment)

Form B.2

ESSENTIAL LOADS IN THE CASE OF CONTINUOUS LOAD REDUCTION (LOAD SHEDDING OR CURTAILMENT)

- Details regarding application for the electrical power requirements during an emergency situation where load is curtailed to customers without an interruption are to be recorded in this appendix.
- This is the power required to sustain life, prevent violation of legislated limits (see foreword) and prevent damage to equipment, plant, facilities, for a limited period during a limited emergency.
- Typically, the outage reduction would last a few hours, generally according to a schedule. Customers should also supply details where extended duration could cause further damage, which may not be realized if the duration were confined to a few hours.
- The numbers here refer to load needed to maintain the plant in stasis without a complete shutdown.
- No power will be available for production requirements, except for temporarily sustaining life, until the load shedding has been switched to another location.

CATEGORY B3: REDUCE POWER TO A LEVEL THAT PREVENTS DESTRUCTION OF OR DAMAGE TO PLANT, EQUIPMENT, OR FACILITIES WHICH WOULD DISRUPT PRODUCTION OF A NATIONALLY CRITICAL PRODUCT

Minimum notification period required before a reduction of power supply. *(Explanation: the amount of time required to ensure that plant, equipment or facilities can be shut down or ramped down so that no destruction or damage occurs.)*	**Minimum load required** *(Explanation: the amount of power required to continuously operate plant, equipment, or facilities such that damage or destruction does not occur; i.e. after ramp-down period, the amount of power required to maintain the status of the plant, equipment or facility.)*	**Details of plant, equipment or facilities which will be operated by the power detailed herein.** *(Please describe what plant will be run by the power required.)*	**In the event of being shed without being reduced, is the amount of load needed different?** *(Explanation: Sometimes the amount of load needed to restart critical equipment or processes is greater than the running load. Please supply details.)*	
HOURS	**MVA**	**Description of minimum load**	**MVA**	**Please give details.**

Annex B
(continued)

CATEGORY B2: REDUCE POWER TO A LEVEL TO PREVENT A POTENTIAL ENVIRONMENTAL OR HEALTH HAZARD				
Minimum notification period required before a reduction of power supply. *(Explanation: the amount of time required to ensure that all activities are completed to avoid damage to a resource or to avoid exceeding a legislated environmental or health limit (or both).)* (see foreword)	**Minimum load required** *(Explanation – the amount of power required to continuously keep the system from exceeding legislated contamination limits* (see foreword) *for the period of the scheduled load shedding.)*	**Details of plant, equipment or facilities which will be operated by the power detailed herein.** *(Please describe what plant will be run by the power required.)*	**In the event of being shed without being reduced, is the amount of load needed different? If so, how much is it?** *(Explanation: Sometimes the amount of load needed to restart critical equipment processes is greater than the running load.)*	
HOURS	**MVA**	**Description of minimum load**	**MVA**	**Please supply details.**

CATEGORY B1: REDUCE POWER TO A LEVEL THAT DOES NOT ENDANGER LIVES AND THE SAFETY OF PERSONS				
Minimum notification period required before a reduction of power supply. *(Explanation: the amount of time required to ensure that all activities can be performed to ensure that no dangerous condition can develop.)*	**Minimum survival load required.** *(Explanation: the amount of load needed to keep the conditions in the plant, facility habitable without performing any actual work or production. People should be able to stay safely where they are for the duration of the load reduction (load shedding) and will not have to be moved. Therefore, power required for evacuating personnel should not be included. Please include power required to restart critical equipment.)*	**Details of plant, equipment or facilities which will be operated by the power detailed herein.** *(Please describe what plant will be run by the power required.)*	**In the event of being reduced without being shed, is the amount of load needed different? If so, how much is it?** *(Explanation: often the amount of load needed to restart critical equipment is greater than the running load. If load critical to sustaining life needs a high start-up power, please put into the field below, while continuous running values can be placed here.)*	
HOURS	**MVA**	**Description of minimum survival demand**	**MVA**	**Please give details.**

SUMMARY FOR ALL THREE CATEGORIES			
Category	**Time (hours)**	**Minimum survival load (MVA)**	**Reduced load (MVA) Demand (MVA)**
B1			
B2			
B3			
TOTAL			

Annex B
(concluded)

B.3 Model form for details of officials to be contacted during emergencies related to power supplies

Form B.3

OFFICIALS TO BE CONTACTED DURING EMERGENCIES RELATED TO POWER SUPPLIES

Official 1: (Primary contact)

Name	
Designation	
E-mail	
Telephone	
Fax	
Cellphone	

Official 2: (Secondary contact)

Name	
Designation	
E-mail	
Telephone	
Fax	
Cellphone	

Official 3: (Alternative 1)

Name	
Designation	
E-mail	
Telephone	
Fax	
Cellphone	

Official 4: (Senior Manager in charge – Last resort contact)

Name	
Designation	
E-mail	
Telephone	
Fax	
Cellphone	

Details of generally manned station such as the Mine Rescue Team (proto team) or main security offices:

Name	
Designation	
E-mail	
Telephone	
Fax	
Cellphone	

Do you have any other means by which the above persons may be contacted, for example, radio, satellite? Give details:

....

Can you offer any further information or motivation not captured elsewhere in this form that will be useful in identifying and evaluating your requirements related to power supplies during emergencies? (Attach separate pages, if required.)

....

Annex C – Practical considerations and alternatives
(informative)

C.1 Overview

This annex provides options on how customers can reduce the impact of emergency load reduction.

C.1 Types of emergency load reduction

The types of emergency reduction defined in this part of NRS 048 are:

a) **load shedding** utilising time-based rotational schedules for stages 1 to 4 and contingency schedules for stages 5 to 8 – this is the default method of load reduction;

b) **load curtailment** – where customers comply with specified curtailment requirement; and

c) **load limiting/switching** – where customers are supplied with smart meters.

C.2 Collaboration between customers or groups of customers

Groups of customers may collaborate and agree with a licensee on how the above options can be accommodated through mutual cooperation. This type of collaboration could be provided by third-parties who establish the necessary protocols, metering and control technologies, and agreements with the licensee.

Examples include:

a) **targeted curtailment**: A mining house with several different facilities may choose to undertake load reduction by significantly curtailing load at one installation, whilst others remain in full production for the full duration of the emergency. This is typically enabled by a central control room at which the total load reduction for all facilities can be monitored and confirmed to be meeting the Stage 1 and 2 requirement of 10 %, the Stage 3 requirement of 15 %, and the Stage 4 requirement of 20 %.

b) **time-aggregated curtailment**: Several customers on a given circuit may agree amongst each other on how load is curtailed to prevent the need for shedding the full circuit that they are being supplied from. This could take the form of customers taking turns to switch off for the duration of the incident. For example, if seven similar-sized customers are supplied by the same feeder, they may each make themselves available on a different day to take up the full load reduction requirement.

c) **demand-aggregated curtailment**: Several customers on a given circuit (for example a large residential estate) may agree to install demand response technologies (such as smart meters) to provide the required load reduction through load limiting or load switching.

Figure D.1 sets out an example of the options for customers and a critical load served by a feeder that serves several customers or groups of customers.

C.3 Considerations

The extent to which a licensee can accommodate specific customers' requests for mitigation of the effects of load shedding will vary on a case by case basis. Licensees cannot commit to accede to all such requests because of network constraints and resource limitations.

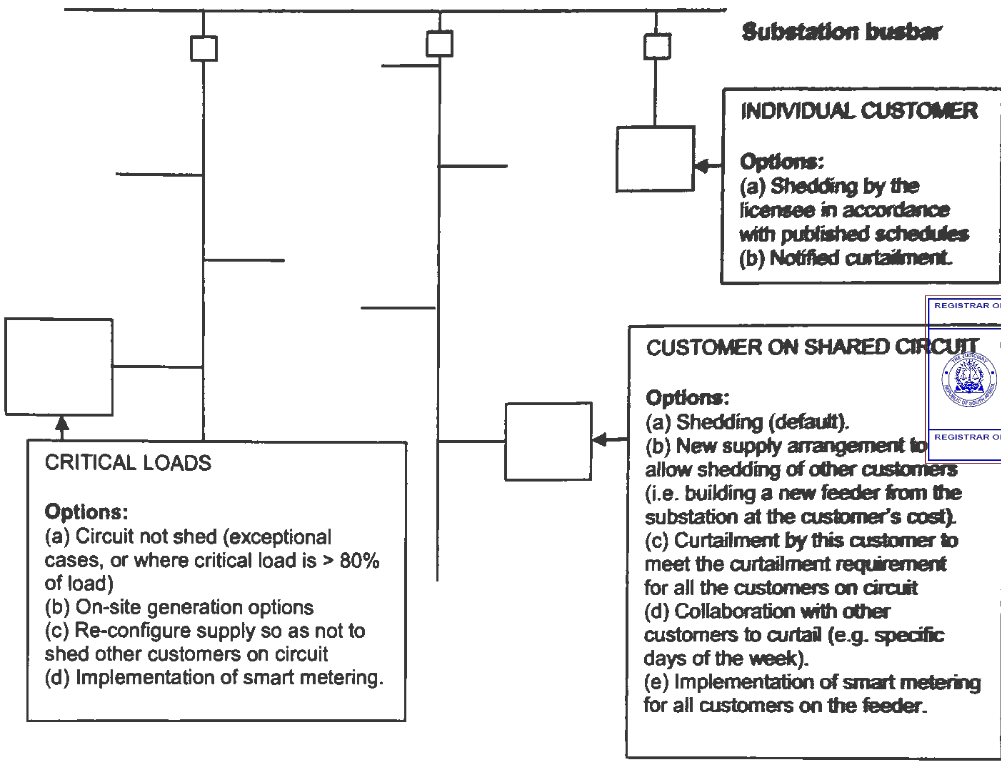


Figure C.1 — Illustration of the options for loads served by a feeder that serves other loads.

Annex D – Background to the approach adopted for setting up load shedding schedules based on fixed stages

(informative)

D.1 Balancing load shedding objectives and practical considerations

D.1.1 From a System Operator's point of view, load shedding would ideally be seen as a resource of a given size (MW) that can be dispatched at any point in the day (i.e. if 1 000 MW is required by the system, the sum of all the load shed by the various licensee control centres will provide this – regardless if this is in winter or summer, at peak or off peak).

D.1.2 Complying with this requirement is, however, complicated by the factors given in (a) to (c).

a) The key objective of ensuring predictability of load shedding for customers requires that specific feeders be pre-selected for each time slot in the load shedding schedule of a given licensee. These feeders will have a varying load profile for different days of the year.

b) Many licensees do not have feeder-level load profile data available in order to build schedules that will provide a specified, equal load reduction at each time slot in a given day. What licensees have available is peak feeder loading.

c) Diversity between licensee load profiles changes throughout the year, making it difficult to provide a given load reduction against a pre-defined schedule.

D.2 Approach adopted

D.2.1 For the above reasons, the approach adopted in this part of NRS 048 is that load shedding will provide the System Operator with a percentage reduction in demand at any point in the daily system profile (i.e. at system peak a stage 1 emergency may provide 1 000 MW at peak and 800 MW at another point during the day – in each case achieving approximately a 5 % reduction in system demand associated with non-curtailment customers).

D.2.2 Should an incident on the system result in an unplanned loss of generation capacity, the System Operator will make a call on the stage of load shedding required to match the evening peak, and to declare this for the period required.

D.2.3 The requirement in this part of NRS 048 is therefore for licensees to build load shedding schedules based on the normal feeder annual peak demand (i.e. excluding abnormal operating conditions). Licensees are further required to take into consideration the diversity between feeders so as to ensure that the overall reduction complies with the requirement in each time slot (and particularly at peak) not to shed feeders at peak that do not contribute to peak demand.

14

Annex E – Model for essential load data for system restoration planning and load shedding – Information required from municipalities and metropolitan municipalities

(normative)

E.1 Form E.1 – Essential loads register questionnaire

General information (information per bill)

NOTE A QUESTIONNAIRE MUST BE COMPLETED FOR EACH SUPPLY POINT REQUIRED

1 Details of customer

1.1	Customer's name:	
1.2	Account number:	
1.3	Physical address:	
1.4	Postal address:	
1.5	Postal code:	

2 Details of point of supply

Normal power provision

2.1	Power supplied from (substation name)	
2.2	Supply voltage	
2.3	Notified and highest maximum demand recorded in the last season	
2.4	Notified maximum demand	
2.5	Highest demand during low season demand (September to May) summer months	
2.6	Highest demand during high season demand (June to August) winter months	

3 Emergency power supply plant facility

3.1 Does your organization have an emergency power procedure and plan to deal with the loss of power supply or other power supply interruptions? (Tick correct option.)

Yes	
No	

If the answer is "NO", when will you have a procedure/plan?

....

3.2 Can you supply your emergency power requirements by means of a standby generator? Tick correct option.

Yes	
No	

Annex E
(continued)

If the answer is **"YES"**, to what category level can you provide own generation according to the attached appendices? (Tick applicable box.):

APPENDIX A (NETWORK COLLAPSE and RESTORE CONDITION)	CAT 1 – PREVENT DANGER TO LIFE and SAFETY	CAT 2 – PREVENT POTENTIAL ENVIRONMENTAL HAZARD	CAT 3 – PREVENT DAMAGE TO EQUIPMENT
APPENDIX B (LOAD SHEDDING OR LOAD REDUCTION CONDITION)	CAT 1 – PREVENT DANGER TO LIFE and SAFETY	CAT 2 – PREVENT POTENTIAL ENVIRONMENTAL HAZARD	CAT 3 – PREVENT DAMAGE TO EQUIPMENT

If the answer is **"NO"**, are the hazards and risks which may be present during loss of power supply or other power supply interruptions adequately addressed in your emergency power procedure/plan?

....

3.3 Standby generator capacity .... MVA

3.4 Maximum duration that the standby generator can be utilized?

Duration without refuelling (hours)	
Duration with refuelling (hours)	

4 Load reduction (load shedding) notification period

What notification period do you require before load reduction commences to ensure that all personnel are removed from high risk areas?

Annex E
(continued)

5 Aggregate of essential load requirements

The following spread sheet should be used to capture all the aggregated information from the municipal customers. Add all the loads required per hour from the time of notification for a national blackout in terms of the categories in the end-use customer essential load forms that you have received from your customers. This will be put into a graphical form for the control centre supplying you. See example in figure F.1.

Time from notification	Category 1 – Safety (MVA)	Category 2 – Environment (MVA)	Category 3 - Nationally critical product plant (MVA)
00:00	0	0	0
01:00	0	0	0
02:00	0	0	0
03:00	0	0	0
04:00	0	0	0
05:00	0	0	0
06:00	0	0	0
07:00	0	0	0
08:00	0	0	0
09:00	0	0	0
10:00	0	0	0
11:00	0	0	0
12:00	0	0	0
13:00	0	0	0
14:00	0	0	0
15:00	0	0	0
16:00	0	0	0
17:00	0	0	0
18:00	0	0	0
19:00	0	0	0
20:00	0	0	0
21:00	0	0	0
22:00	0	0	0
23:00	0	0	0
00:00	0	0	0

Annex E
(continued)

6 Official(s) to be contacted during emergencies related to power supplies:

Official 1: (Primary contact)

Name	
Designation	
E-mail	
Telephone	
Fax	
Cellphone	

Official 2: (Secondary contact)

Name	
Designation	
E-mail	
Telephone	
Fax	
Cellphone	

Official 3: (Alternate 1)

Name	
Designation	
E-mail	
Telephone	
Fax	
Cellphone	

Official 4: (Senior manager in charge – Last resort contact)

Name	
Designation	
E-mail	
Telephone	
Fax	
Cellphone	

Details of generally manned station such as the control centre

Name	
Designation	
E-mail	
Telephone	
Fax	
Cellphone	

Do you have any other means by which the above persons may be contacted, for example, radio, satellite? Give details:

....

....

Annex E
(continued)

Can you offer any further information or motivation that is not captured elsewhere in this questionnaire which will be useful in identifying and evaluating your requirements during emergencies related to power supplies?

....

....

7 General

7.1 Submit this form via e-mail or fax or arrange to have it delivered by hand to your relevant Customer Executive. Please confirm via email that your Customer Executive has received the form, and keep a record of the confirmation.

Customer Executive's name: ....

Telephone number: ....

Fax number: ....

Cellphone number: ....

E-mail address: ....

Date submitted: ....

7.2 If you do not receive an acknowledgement of receipt within 21 days, please contact your relevant Customer Executive.

7.3 Information in this questionnaire will be treated as confidential and should be certified as correct by a person from top management such as a director or general manager.

INFORMATION CERTIFIED AS CORRECT: ....

NAME AND SURNAME: ....

DESIGNATION: ....

SIGNATURE: ....

DATE: ....

22/12/2022-11:31:00 AM

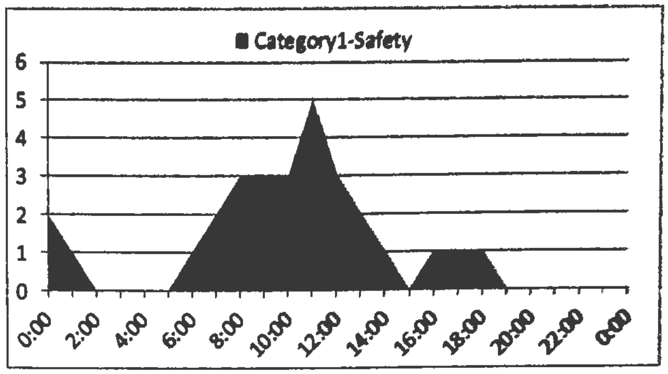
0278

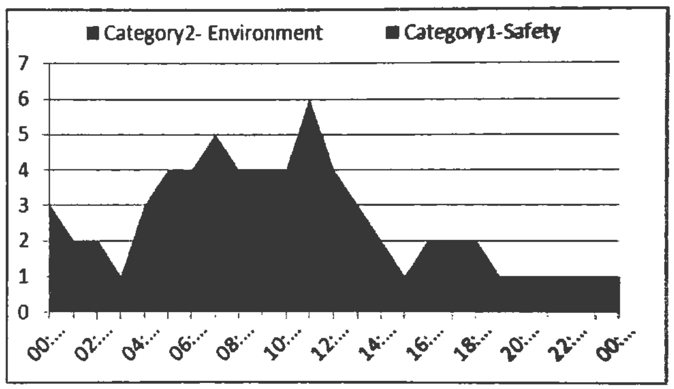
Annex E
(continued)

E.2 Example of graphical form of aggregated end-use customers' essential loads

Time from notification		Category 2 Environment	[illegible]
00:00	2	1	0
01:00	1	1	0
02:00	0	2	2
03:00	0	1	3
04:00	0	3	2
05:00	0	4	1
06:00	1	3	0
07:00	2	3	0
08:00	3	1	1
09:00	3	1	1,5
10:00	3	1	2
11:00	5	1	2
12:00	3	1	1,5
13:00	2	1	1
14:00	1	1	0
15:00	0	1	0
16:00	1	1	0
17:00	1	1	0
18:00	1	1	0
19:00	0	1	0
20:00	0	1	0
21:00	0	1	0
22:00	0	1	0
23:00	0	1	0
00:00	0	1	0

Annex E
(concluded)





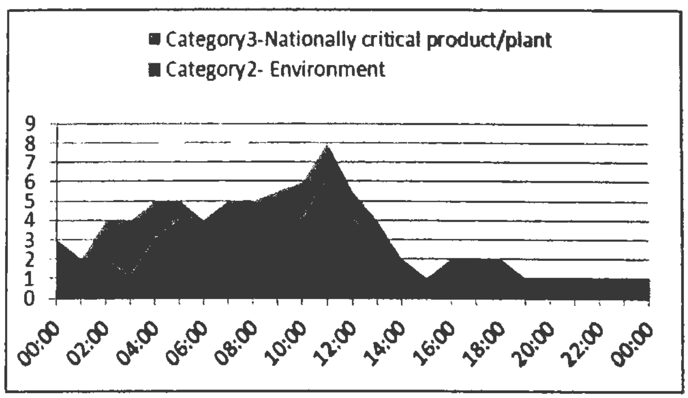
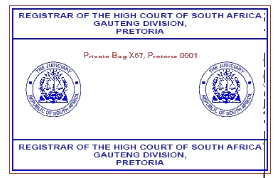


Figure E.1 — Example of graphical form of aggregated end-use customers' essential loads



Annex F – Development of load shedding schedules
(informative)

F.1 Option 1: 16/19 block expansion (see example schedules in annex G)

F.1.1 Stage 1 (scheduled)

The non-curtailment load (sheddable load), as determined in 4.8.2, should be divided into 19 blocks of load, as close to the same size as possible, based on the peak load values at the identified points of shedding. These blocks will then be arranged to follow each other on a 24 hour rotation, in accordance with the 2, 3 or 4 hour based schedules described in annex G. Each load block size will be at least 5 % of sheddable load.

NOTE 1 Each block must be at least 5% of the load. This leaves 5% available to manage the potential unequal block sizes, and a modest amount of critical load.

NOTE 2 Published schedules will indicate that customers are impacted for 2, 3 or 4 hours at a time. In practice, each time slot may overlap its adjacent time slot by an additional 0,5 h to facilitate smooth change over. The potential 0,5 h overlap should be noted in the communication of the schedules

F.1.2 Stage 2 (scheduled)

Using the 19 blocks described in stage 1, the licensee will schedule two such blocks in each of the time periods described in stage 1. The licensee will ensure that the same load block is not repeated in consecutive time periods. An example is illustrated in Annex G. Each load block size will be at least 10 % of sheddable load.

F.1.3 Stage 3 (scheduled)

Using the load blocks resulting from stage 2 and stage 1, the licensee will schedule two such blocks from each stage in each of the time periods described in stage 1. The licensee will ensure that the same load block is not repeated in consecutive time periods. An example is illustrated in annex G. Each load block size will be at least 15 % of sheddable load.

F.1.4 Stage 4 (scheduled)

Using the load blocks resulting from stage 2, the licensee will schedule two such blocks in each of the time periods described in stage 1. The licensee will ensure that the same load block is not repeated in consecutive time periods. An example is illustrated in annex G. Each load block size will be at least 20 % of sheddable load.

F.2 Option 2: 24 block expansion (see example schedules in annex H)

F.2.1 Stage 1 (scheduled)

5 % of the non-curtailment load, as determined in 4.8.5 shall be determined. The load allocated to the 24 blocks shall be based on the peak load values at the identified points of shedding. These blocks will then be arranged to follow each other on a 24 hour rotation, in accordance with the 2 hour schedule. Each load block size will be at least 5% of the sheddable load.

NOTE 1 Each block must be at least 5 % of the load. This leaves 5 % available to manage the potential unequal block sizes, and a modest amount of critical load.

NOTE 2 Published schedules will indicate that customers are impacted for 2 hours at a time. In practice, each time slot may overlap its adjacent time slot by an additional 0,5 h to facilitate smooth change over. The potential 0,5 h overlap should be noted in the communication of the schedules.

Annex F
(concluded)

F.2.2 Stage 2 (scheduled)

Using the 24 blocks described in stage 1, the licensee will schedule two such blocks in each of the time periods described in stage 1. The licensee will ensure that the same load block is not repeated in consecutive time periods. An example is illustrated in annex H. Each load block size will be at least 10 % of sheddable load.

F.2.3 Stage 3 (scheduled)

Using the load block from Stage 2 and adding another block the licensee will ensure that the same load block is not repeated in consecutive time periods. Each total load block size will be at least 15 % of sheddable load.

F.2.4 Stage 4 (scheduled)

Using the load blocks resulting from stage 3, the licensee will schedule another block. Each total load block size will be at least 20 % of sheddable load.

Annex G – Examples of 24/7 rotational load shedding schedules based on 19 blocks

(informative)

G.1 Overview

Typical model load shedding schedules are shown in this annex, based on the 19 blocks identified for the load shedding schedules, as described in annex F. The model schedules provided address load shedding periods of 2hrs (figure G.1), 3hrs (figure G.2), and 4hrs (figure G.3).

Licensees may use these model schedules to generate their own schedules based on the normative requirements in sections 1 to 10 of this Code.

G.2 Methodology

The assumption made in the examples provided is that the base load has been divided into 19 equal blocks, of between 5 and 6% of the base load each. These are then rotated across the day, over all 24 hours, and all 7 days of the week. In this case the pattern is expected to repeat every 19 days.

Figure G.1 — Model load shedding schedule for a 2 hour shedding period (each number in the table designates the number of the block shed of the 19 blocks)

Day	Stage	00:00 - 02:00	02:00 - 04:00	04:00 - 06:00	06:00 - 08:00	08:00 - 10:00	10:00 - 12:00	12:00 - 14:00	14:00 - 16:00	16:00 - 18:00	18:00- 20:00	20:00 - 22:00	22:00 - 00:00
1	Stage 1	1	2	3	4	5	6	7	8	9	10	11	12
	Stage 2	1,6	2,7	3,8	4,9	5,10	6,11	7,12	8,13	9,14	10,15	11,16	12,17
	Stage 3	1,6,11	2,7,12	3,8,13	4,9,14	5,10,15	6,11,16	7,12,17	8,13,18	9,14,19	10,15,1	11,16,2	12,17,3
	Stage 4	1,6,11,16	2,7,12,17	3,8,13,18	4,9,14,19	5,10,15,1	6,11,16,2	7,12,17,3	8,13,18,4	9,14,19,5	10,15,1,6	11,16,2,7	12,17,3,8
2	Stage 1	13	14	15	16	17	18	19	1	2	3	4	5
	Stage 2	13,18	14,19	15,1	16,2	17,3	18,4	19,5	1,6	2,7	3,8	4,9	5,10
	Stage 3	13,18,4	14,19,5	15,1,6	16,2,7	17,3,8	18,4,9	19,5,10	1,6,11	2,7,12	3,8,13	4,9,14	5,10,15
	Stage 4	13,18,4,9	14,19,5,10	15,1,6,11	16,2,7,12	17,3,8,13	18,4,9,14	19,5,10,15	1,6,11,16	2,7,12,17	3,8,13,18	4,9,14,19	5,10,15,1

0282

74

Annex G
(continued)

3	Stage 1	6	7	8	9	10	11	12	13	14	15	16	17
	Stage 2	6,11	7,12	8,13	9,14	10,15	11,16	12,17	13,18	14,19	15,1	16,2	17,3
	Stage 3												
	Stage 4	6,11,16,2	7,12,17,3	8,13,18,4	9,14,19,5	10,15,1,6	11,16,2,7	12,17,3,8	13,18,4,9	14,19,5,10	15,1,6,11	16,2,7,12	17,3,8,13
4	Stage 1	18	19	1	2	3	4	5	6	7	8	9	10
	Stage 2	18,4	19,5	1,6	2,7	3,8	4,9	5,10	6,11	7,12	8,13	9,14	10,15
	Stage 3												
	Stage 4	18,4,9,14	19,5,10,15	1,6,11,16	2,7,12,17	3,8,13,18	4,9,14,19	5,10,15,1	6,11,16,2	7,12,17,3	8,13,18,4	9,14,19,5	10,15,1,6
5	Stage 1	11	12	13	14	15	16	17	18	19	1	2	3
	Stage 2	11,16	12,17	13,18	14,19	15,1	16,2	17,3	18,4	19,5	1,6	2,7	3,8
	Stage 3												
	Stage 4	11,16,2,7	12,17,3,8	13,18,4,9	14,19,5,10	15,1,6,11	16,2,7,12	17,3,8,13	18,4,9,14	19,5,10,15	1,6,11,16	2,7,12,17	3,8,13,18
6	Stage 1	4	5	6	7	8	9	10	11	12	13	14	15
	Stage 2	4,9	5,10	6,11	7,12	8,13	9,14	10,15	11,16	12,17	13,18	14,19	15,1
	Stage 3												
	Stage 4	4,9,14,19	5,10,15,1	6,11,16,2	7,12,17,3	8,13,18,4	9,14,19,5	10,15,1,6	11,16,2,7	12,17,3,8	13,18,4,9	14,19,5,10	15,1,6,11
7	Stage 1	16	17	18	19	1	2	3	4	5	6	7	8
	Stage 2	16,2	17,3	18,4	19,5	1,6	2,7	3,8	4,9	5,10	6,11	[illegible]	[illegible]
	Stage 3												
	Stage 4	16,2,7,12	17,3,8,13	18,4,9,14	19,5,10,15	1,6,11,16	2,7,12,17	3,8,13,18	4,9,14,19	5,10,15,1	6,11,16,2	7,12,17,3	8,13,18,4

0283

74

Annex G
(continued)

8	Stage 1	9	10	11	12	13	14	15	16	17	18	19	1
	Stage 2	9,14	10,15	11,16	12,17	13,18	14,19	15,1	16,2	17,3	18,4	19,5	1,6
	Stage 3												
	Stage 4	9,14,19,5	10,15,1,6	11,16,2,7	12,17,3,8	13,18,4,9	14,19,5,10	15,1,6,11	16,2,7,12	17,3,8,13	18,4,9,14	19,5,10,15	1.6,11,16
9	Stage 1	2	3	4	5	6	7	8	9	10	11	12	13
	Stage 2	2,7	3,8	4,9	5,10	6,11	7,12	8,13	9,14	10,15	11,16	12,17	13,18
	Stage 3												
	Stage 4	2,7,12,17	3,8,13,18	4,9,14,19	5,10,15,1	6,11,16,2	7,12,17,3	8,13,18,4	9,14,19,5	10,15,1,6	11,16,2,7	12,17,3.8	13.18,4,9
10	Stage 1	14	15	16	17	18	19	1	2	3	4	5	6
	Stage 2	14,19	15,1	16,2	17,3	18,4	19,5	1,6	2,7	3,8	4,9	5,10	6,11
	Stage 3												
	Stage 4	14,19,5,10	15,1,6,11	16,2,7,12	17,3,8,13	18,4,9,14	19,5,10,15	1,6,11,16	2,7,12,17	3,8,13,18	4,9,14,19	5.10.15.1	6.11.16.2
11	Stage 1	7	8	9	10	11	12	13	14	15	16	17	18
	Stage 2	7,12	8,13	9,14	10,15	11,16	12,17	13,18	14,19	15,1	16,2	17,3	18,4
	Stage 3												
	Stage 4	7,12,17,3	8,13,18,4	9,14,19,5	10,15,1,6	11,16,2,7	12,17,3,8	13,18,4,9	14,19,5,10	15,1,6,11	16.2,7,12	17.3.8.13	18,4.9.14
12	Stage 1	19	1	2	3	4	5	6	7	8	9	10	11
	Stage 2	19,5	1,6	2,7	3,8	4,9	5,10	6,11	7,12	8,13	9,14	[illegible]	[illegible]
	Stage 3												
	Stage 4	19,5,10,15	1,6,11,16	2,7,12,17	3,8,13,18	4,9,14,19	5,10,15,1	6,11,16,2	7.12.17.3	8.13.18.4	[illegible]	[illegible]	[illegible]

0284

Annex G
(continued)

13	Stage 1	12	13	14	15	16	17	18	19	1	2	3	4
	Stage 2	12,17	13,18	14,19	15,1	16,2	17,3	18,4	19,5	1,6	2,7	3,8	4,9
	Stage 3												
	Stage 4	12,17,3,8	13,18,4,9	14,19,5,10	15,1,6,11	16,2,7,12	17,3,8,13	18,4,9,14	19,5,10,15	1,6,11,16	2,7,12,17	3,8,13,18	4,9,14,19
14	Stage 1	5	6	7	8	9	10	11	12	13	14	15	16
	Stage 2	5,10	6,11	7,12	8,13	9,14	10,15	11,16	12,17	13,18	14,19	15,1	16,2
	Stage 3												
	Stage 4	5,10,15,1	6,11,16,2	7,12,17,3	8,13,18,4	9,14,19,5	10,15,1,6	11,16,2,7	12,17,3,8	13,18,4,9	14,19,5,10	15,1,6,11	16,2,7,12
15	Stage 1	17	18	19	1	2	3	4	5	6	7	8	9
	Stage 2	17,3	18,4	19,5	1,6	2,7	3,8	4,9	5,10	6,11	7,12	8,13	9,14
	Stage 3												
	Stage 4	17,3,8,13	18,4,9,14	19,5,10,15	1,6,11,16	2,7,12,17	3,8,13,18	4,9,14,19	5,10,15,1	6,11,16,2	7,12,17,3	8,13,18,4	9,14,19,5
16	Stage 1	10	11	12	13	14	15	16	17	18	19	1	2
	Stage 2	10,15	11,16	12,17	13,18	14,19	15,1	16,2	17,3	18,4	19,5	1,6	2,7
	Stage 3												
	Stage 4	10,15,1,6	11,16,2,7	12,17,3,8	13,18,4,9	14,19,5,10	15,1,6,11	16,2,7,12	17,3,8,13	18,4,9,14	19,5,10,15	1,6,11,16	2,7,12,17
17	Stage 1	3	4	5	6	7	8	9	10	11	12	13	14
	Stage 2	3,8	4,9	5,10	6,11	7,12	8,13	9,14	10,15	[illegible]	[illegible]	[illegible]	[illegible]
	Stage 3												
	Stage 4	3,8,13,18	4,9,14,19	5,10,15,1	6,11,16,2	7,12,17,3	8,13,18,4	9,14,19,5	10,15,1,6	11,16,2,[illegible]	12,1[illegible],3,8	13,18,4,9	14,19,5,10

0285

Annex G
(continued)

18	Stage 1	15	16	17	18	19	1	2	3	4	5	6	7
	Stage 2	15,1	16,2	17,3	18,4	19,5	1,6	2,7	3,8	4,9	5,10	6,11	7,12
	Stage 3	15,1,6	16,2,7	17,3,8	18,4,9	19,5,10	1,6,11	2,7,12	3,8,13	4,9,14	5,10,15	6,11,16	7,12,17
	Stage 4	15,1,6,11	16,2,7,12	17,3,8,13	18,4,9,14	19,5,10,15	1,6,11,16	2,7,12,17	3,8,13,18	4,9,14,19	5,10,15,1	6,11,16,2	7,12,17,3
19	Stage 1	8	9	10	11	12	13	14	15	16	17	18	19
	Stage 2	8,13	9,14	10,15	11,16	12,17	13,18	14,19	15,1	16,2	17,3	18,4	19,5
	Stage 3	8,13,18	9,14,19	10,15,1	11,16,2	12,17,3	13,18,4	14,19,5	15,1,6	16,2,7	17,3,8	18,4,9	19,5,10
	Stage 4	8,13,18,4	9,14,19,5	10,15,1,6	11,16,2,7	12,17,3,8	13,18,4,9	14,19,5,10	15,1,6,11	16,2,7,12	17,3,8,13	18,4,9,14	19,5,10,15

0286

Annex G
(continued)

Figure G.2 — Model load shedding schedule for a 3 hour shedding period (each number in the table designates the number of the block shed of the 19 blocks)

Day	Stage	00:00 - 03:00	03:00 - 06:00	06:00 - 09:00	09:00 - 12:00	12:00 - 15:00	15:00 - 18:00	18:00 - 21:00	21:00 - 00:00
1	Stage 1	1	2	3	4	5	6	7	8
	Stage 2	1,17	2,18	3,19	4,1	5,2	6,3	7,4	8,5
	Stage 3								
	Stage 4	1,17,14,11	2,18,15,12	3,19,16,13	4,1,17,14	5,2,18,15	6,3,19,16	7,4,1,17	8,5,2,18
2	Stage 1	9	10	11	12	13	14	15	16
	Stage 2	9,6	10,7	11,8	12,9	13,10	14,11	15,12	16,13
	Stage 3								
	Stage 4	9,6,3,19	10,7,4,1	11,8,5,2	12,9,6,3	13,10,7,4	14,11,8,5	15,12,9,6	16,13.10.7
3	Stage 1	17	18	19	1	2	3	4	5
	Stage 2	17,14	18,15	19,16	1,17	2,18	3,19	4,1	5,2
	Stage 3								
	Stage 4	17,14,11,8	18,15,12,9	19,16,13,10	1,17,14,11	2,18,15,12	3,19,16,13	4,1,17,14	5.2.18.15
4	Stage 1	6	7	8	9	10	11	12	13
	Stage 2	6,3	7,4	8,5	9,6	10,7	11,8	12,9	13,10
	Stage 3								
	Stage 4	6,3,19,16	7,4,1,17	8,5,2,18	9,6,3,19	10,7,4,1	11,8,5,2	12.9.6.3	13.10.7.4
5	Stage 1	14	15	16	17	18	19	1	2
	Stage 2	14,11	15,12	16,13	17,14	18,15	19,16	[illegible]	[illegible]
	Stage 3								
	Stage 4	14,11,8,5	15,12,9,6	16,13,10,7	17,14,11,8	18,15,12,9	19,16,13,10	1,17,14,11	2,18,15,12

0287

Annex G
(continued)

6	Stage 1	3	4	5	6
	Stage 2	3,19	4,1	5,2	6,3
	Stage 3				
	Stage 4	3,19,16,13	4,1,17,14	5,2,18,15	6,3,19,16
7	Stage 1	11	12	13	14
	Stage 2	11,8	12,9	13,10	14,11
	Stage 3				
	Stage 4	11,8,5,2	12,9,6,3	13,10,7,4	14,11,8,5
8	Stage 1	19	1	2	3
	Stage 2	19,16	1,17	2,18	3,19
	Stage 3				
	Stage 4	19,16,13,10	1,17,14,11	2,18,15,12	3,19,16,13
9	Stage 1	8	9	10	11
	Stage 2	8,5	9,6	10,7	11,8
	Stage 3				
	Stage 4	8,5,2,18	9,6,3,19	10,7,4,1	11,8,5,2
10	Stage 1	16	17	18	19
	Stage 2	16,13	17,14	18,15	19,16
	Stage 3				
	Stage 4	16,13,10,7	17,14,11,8	18,15,12,9	19,16,13,10

6	Stage 1	7	8	9	10
	Stage 2	7,4	8,5	9,6	10,7
	Stage 3				
	Stage 4	7,4,1,17	8,5,2,18	9,6,3,19	10,7,4,1
7	Stage 1	15	16	17	18
	Stage 2	15,12	16,13	17,14	18,15
	Stage 3				
	Stage 4	15,12,9,6	16,13,10,7	17,14,11,8	18,15,12,9
8	Stage 1	4	5	6	7
	Stage 2	4,1	5,2	6,3	7,4
	Stage 3				
	Stage 4	4,1,17,14	5,2,18,15	6,3,19,16	7.4.1.17
9	Stage 1	12	13	14	15
	Stage 2	12,9	13,10	14,11	15,12
	Stage 3				
	Stage 4	12,9,6,3	13,10,7,4	14,11,8.5	15.12.9.6
10	Stage 1	1	2	3	4
	Stage 2	1,17	2,18	3,19	4,1
	Stage 3				
	Stage 4	1,17,14,11	2,18,15,12	3,19,16,13	4,1,17,14

0288

Annex G
(continued)

11	Stage 1	5	6	7	8	9	10	11	12
	Stage 2	5,2	6,3	7,4	8,5	9,6	10,7	11,8	12,9
	Stage 3								
	Stage 4	5,2,18,15	6,3,19,16	7,4,1,17	8,5,2,18	9,6,3,19	10,7,4,1	11,8,5,2	12,9,6,3
12	Stage 1	13	14	15	16	17	18	19	1
	Stage 2	13,10	14,11	15,12	16,13	17,14	18,15	19,16	1,17
	Stage 3								
	Stage 4	13,10,7,4	14,11,8,5	15,12,9,6	16,13,10,7	17,14,11,8	18,15,12,9	19,16,13,10	1,17,14,11
13	Stage 1	2	3	4	5	6	7	8	9
	Stage 2	2,18	3,19	4,1	5,2	6,3	7,4	8,5	9,6
	Stage 3								
	Stage 4	2,18,15,12	3,19,16,13	4,1,17,14	5,2,18,15	6,3,19,16	7,4,1,17	8,5,2,18	9,6,3,19
14	Stage 1	10	11	12	13	14	15	16	17
	Stage 2	10,7	11,8	12,9	13,10	14,11	15,12	16,13	17,14
	Stage 3								
	Stage 4	10,7,4,1	11,8,5,2	12,9,6,3	13,10,7,4	14,11,8,5	15,12,9,6	16,13,10,7	17,14,11,8
15	Stage 1	18	19	1	2	3	4	5	6
	Stage 2	18,15	19,16	1,17	2,18	3,19	4,1	5,2	6,3
	Stage 3								
	Stage 4	18,15,12,9	19,16,13,10	1,17,14,11	2,18,15,12	3,19,16,13	4,1,17,14	5,2,18,15	6,3,19,16
16	Stage 1	7	8	9	10	11	12	13	14
	Stage 2	7,4	8,5	9,6	10,7	11,8	12,9	13,10	14,11
	Stage 3								
	Stage 4	7,4,1,17	8,5,2,18	9,6,3,19	10,7,4,1	11,8,5,2	12,9,6,3	13,10,7,4	14,11,8,5

0289

Annex G
(continued)

17	Stage 1	15	16	17	18	19	1	2	3
	Stage 2	15,12	16,13	17,14	18,15	19,16	1,17	2,18	3,19
	Stage 3								
	Stage 4	15,12,9,6	16,13,10,7	17,14,11,8	18,15,12,9	19,16,13,10	1,17,14,11	2,18,15,12	3,19,16,13
18	Stage 1	4	5	6	7	8	9	10	11
	Stage 2	4,1	5,2	6,3	7,4	8,5	9,6	10,7	11,8
	Stage 3								
	Stage 4	4,1,17,14	5,2,18,15	6,3,19,16	7,4,1,17	8,5,2,18	9,6,3,19	10,7,4,1	11,8,5,2
19	Stage 1	12	13	14	15	16	17	18	19
	Stage 2	12,9	13,10	14,11	15,12	16,13	17,14	18,15	19,16
	Stage 3								
	Stage 4	12,9,6,3	13,10,7,4	14,11,8,5	15,12,9,6	16,13,10,7	17,14,11,8	18,15,12,9	19,16,13,10

0290

Annex G
(continued)

Figure G.3 — Model load shedding schedule for a 4 hour shedding period (each number in the table designates the number of the block shed of the 19 blocks)

Day	Stage	00:00 - 04:00	04:00 - 08:00	08:00 - 12:00	12:00 - 16:00	16:00 - 20:00	20:00 - 00:00
1	Stage 1	1	2	3	4	5	6
	Stage 2	1,13	2,14	3,15	4,16	5,17	6,18
	Stage 3						
	Stage 4	1,13,6,18	2,14,7,19	3,15,8,1	4,16,9,2	5,17,10,3	6,18,11,4
2	Stage 1	7	8	9	10	11	12
	Stage 2	7,19	8,1	9,2	10,3	11,4	12,5
	Stage 3						
	Stage 4	7,19,12,5	8,1,13,6	9,2,14,7	10,3,15,8	11,4,16,9	12,5,17,10
3	Stage 1	13	14	15	16	17	18
	Stage 2	13,6	14,7	15,8	16,9	17,10	18,11
	Stage 3						
	Stage 4	13,6,18,11	14,7,19,12	15,8,1,13	16,9,2,14	17,10,3,15	18,11,4,16
4	Stage 1	19	1	2	3	4	5
	Stage 2	19,12	1,13	2,14	3,15	4,16	5,17
	Stage 3						
	Stage 4	19,12,5,17	1,13,6,18	2,14,7,19	3,15,8,1	4,16,9,2	5,17,10,3
5	Stage 1	6	7	8	9	10	11
	Stage 2	6,18	7,19	8,1	9,2	10,3	11,4
	Stage 3						
	Stage 4	6,18,11,4	7,19,12,5	8,1,13,6	9,2,14,7	10,3,15,8	11,4,16,9

Annex G

0291

(continued)

6	Stage 1	12	13	14	15	16	17
	Stage 2	12,5	13,6	14,7	15,8	16,9	17,10
	Stage 3	12,5,17	13,6,18	14,7,19	15,8,1	16,9,2	17,10,3
	Stage 4	12,5,17,10	13,6,18,11	14,7,19,12	15,8,1,13	16,9,2,14	17,10,3,15
7	Stage 1	18	19	1	2	3	4
	Stage 2	18,11	19,12	1,13	2,14	3,15	4,16
	Stage 3	18,11,4	19,12,5	1,13,6	2,14,7	3,15,8	4,16,9
	Stage 4	18,11,4,16	19,12,5,17	1,13,6,18	2,14,7,19	3,15,8,1	4,16,9,2
8	Stage 1	5	6	7	8	9	10
	Stage 2	5,17	6,18	7,19	8,1	9,2	10,3
	Stage 3	5,17,10	6,18,11	7,19,12	8,1,13	9,2,14	10,3,15
	Stage 4	5,17,10,3	6,18,11,4	7,19,12,5	8,1,13,6	9,2,14,7	10,3,15,8
9	Stage 1	11	12	13	14	15	16
	Stage 2	11,4	12,5	13,6	14,7	15,8	16,9
	Stage 3	11,4,16	12,5,17	13,6,18	14,7,19	15,8,1	16,9,2
	Stage 4	11,4,16,9	12,5,17,10	13,6,18,11	14,7,19,12	15,8,1,13	16,9,2,14
10	Stage 1	17	18	19	1	2	3
	Stage 2	17,10	18,11	19,12	1,13	2,14	3,15
	Stage 3	17,10,3	18,11,4	19,12,5	1,13,6	2,14,7	3,15,8
	Stage 4	17,10,3,15	18,11,4,16	19,12,5,17	1,13,6,18	2,14,7,19	3,15,8,1

0292

Annex G
(continued)

11	Stage 1	4	5	6	7	8	9
	Stage 2	4,16	5,17	6,18	7,19	8,1	9,2
	Stage 3						
	Stage 4	4,16,9,2	5,17,10,3	6,18,11,4	7,19,12,5	8,1,13,6	9,2,14,7
12	Stage 1	10	11	12	13	14	15
	Stage 2	10,3	11,4	12,5	13,6	14,7	15,8
	Stage 3						
	Stage 4	10,3,15,8	11,4,16,9	12,5,17,10	13,6,18,11	14,7,19,12	15,8,1,13
13	Stage 1	16	17	18	19	1	2
	Stage 2	16,9	17,10	18,11	19,12	1,13	2,14
	Stage 3						
	Stage 4	16,9,2,14	17,10,3,15	18,11,4,16	19,12,5,17	1,13,6,18	2,14,7,19
14	Stage 1	3	4	5	6	7	8
	Stage 2	3,15	4,16	5,17	6,18	7,19	8,1
	Stage 3						
	Stage 4	3,15,8,1	4,16,9,2	5,17,10,3	6,18,11,4	7,19,12,5	8,1,13,6
15	Stage 1	9	10	11	12	13	14
	Stage 2	9,2	10,3	11,4	12,5	13,6	14,7
	Stage 3						
	Stage 4	9,2,14,7	10,3,15,8	11,4,16,9	12,5,17,10	13,6,18,11	14,7,19,12
16	Stage 1	15	16	17	18	19	1
	Stage 2	15,8	16,9	17,10	18,11	19,12	1,13
	Stage 3						
	Stage 4	15,8,1,13	16,9,2,14	17,10,3,15	18,11,4,16	19,12,5,17	1,13,6,18

0293

22/12/2022-11:31:00 AM

Annex G
(continued)

17	Stage 1	2	3	4	5	6	7
	Stage 2	2,14	3,15	4,16	5,17	6,18	7,19
	Stage 3						
	Stage 4	2,14,7,19	3,15,8,1	4,16,9,2	5,17,10,3	6,18,11,4	7,19,12,5
18	Stage 1	8	9	10	11	12	13
	Stage 2	8,1	9,2	10,3	11,4	12,5	13,6
	Stage 3						
	Stage 4	8,1,13,6	9,2,14,7	10,3,15,8	11,4,16,9	12,5,17,10	13,6,18,11
19	Stage 1	14	15	16	17	18	19
	Stage 2	14,7	15,8	16,9	17,10	18,11	19,12
	Stage 3						
	Stage 4	14,7,19,12	15,8,1,13	16,9,2,14	17,10,3,15	18,11,4,16	19,12,5,17

0294

Annex H – Examples of 24/7 rotational load shedding schedules based on 24 blocks

(informative)

H.1 Overview

Typical model load shedding schedules are shown in this annex, based on the 24 blocks identified for the load shedding schedules, as described in Annex F (section F.2). The model schedules provided address load shedding periods of 2hrs (figure H.1).

Licensees may use these model schedules to generate their own schedules based on the normative requirements in sections 1 to 10 of this code.

H.2 Methodology

The assumption made in the examples provided is that the base load has been divided into 24 equal blocks, of between 5 % and 6 % of the base load each. These are then rotated across the day, over all 24 hours, and all 7 days of the week.

The schedule is designed from Monday to Sunday, 24/7 for Stages 1 to 4, from 06h00 to 22h00 (the likely period of load shedding) and from 22h00 to 06h00 (the unlikely period of load shedding). The following is applied:

a) the schedule is made up of blocks and each block is scheduled for 2 hours with a 30 minute overlap to allow for switching. Two (2) hour blocks are designed to prevent numerous waiting load trip outs when restoring supply and to prevent a customer from experiencing a prolonged outage. However, it was noted that certain industrial customers preferred a longer time period for their block under Stage 3 and 4 due to the start-up time requirements which was not accommodated;

b) the blocks are labeled from 1-24. Blocks 1-16 are largely residential and commercial type customers and blocks 17-24 are largely industrial customers;

c) from Monday to Sunday, blocks 1-16 are included from Stage 1 and blocks 17-24 are included from Stage 3;

d) the minimum duration before a block is shed again under the relevant stages for the likely period (06h00 to 22h00) of load shedding from Monday to Sunday are:

   i) Stage 1, a block (hence customer) will be affected every second day (48 hours);
   ii) Stage 2 and 3, a block will be affected once a day (24 hours); and
   iii) Stage 4, a block will be affected once a day and twice a day for every second day with a 6 hour break.

e) blocks 1-16 are only scheduled under the relevant stages for the unlikely period (22h00 to 06h00) of load shedding from Monday to Sunday;

f) the block allocation to the time periods during the likely period of load shedding from Monday to Sunday adheres to the following:

   i) Blocks 1-16 are rotated in the morning, day and evening periods,
   ii) 06h00 to 08h00 is considered the morning period, 08h00 to 16h00 is considered the day period and 16h00 to 22h00 is considered the evening period, and
   iii) A block under Stage 1 has no more than 2 evening time periods and under Stage 2 and 3 has no more than 3 evening time periods.

22/12/2022-11:31:00 AM

0296

Annex H
(continued)

g) a block has no more than one consecutive evening time period;

h) blocks remained grouped throughout the week for Stages 1, 2 and 3;

i) the time periods allocated to the different blocks ensure that there is full rotation from Monday to Sunday for the likely period of load shedding considering a Stage 2 emergency. (i.e. no block has a repeat time slot); and

j) blocks 12, 13 and 15 are used to accommodate traffic congestion in the City Centre and adheres to the following:

i) These blocks are not allocated from 06h00 to 08h00 from Wednesday to Friday; and
ii) These blocks are not allocated from 16h00 to 18h00 from Monday to Friday.

Annex H
(continued)

	Monday				Tuesday			
Time	Stage 1	Stage 2	Stage 3	Stage 4	Stage 1	Stage 2	Stage 3	Stage 4
00:00-02:00	6	6,11	6,11,13	6,11,13,4	3	3,16	3,16,2	3,16,2,7
02:00-04:00	16	16,3	16,3,7	16,3,7,2	12	12,8	12,8,4	12,8,4,13
04:00-06:00	15	15,4	15,4,8	15,4,8,9	10	10,7	10,7,11	10,7,11,5
06:00-08:00	2	2,13	2,13,23	2,13,23,11	8	8,12	8,12,24	8,12,24,14
08:00-10:00	9	9,5	9,5,19	9,5,19,1	13	13,2	13,2,23	13,2,23,5
10:00-12:00	3	3,16	3,16,17	3,16,17,10	6	6,11	6,11,18	6,11,18,15
12:00-14:00	4	4,15	4,15,21	4,15,21,12	16	16,3	16,3,17	16,3,17,7
14:00-16:00	11	11,6	11,6,18	11,6,18,2	14	14,1	14,1,20	14,1,20,8
16:00-18:00	1	1,14	1,14,20	1,14,20,9	5	5,9	5,9,19	5,9,19,13
18:00-20:00	10	10,7	10,7,22	10,7,22,3	15	15,4	15,4,21	15,4,21,6
20:00-22:00	12	12,8	12,8,24	12,8,24,4	7	7,10	7,10,22	7,10,22,16
22:00-00:00	14	14,1	14,1,5	14,1,5,10	1	1,14	1,14,9	1,14,9,8

	Wednesday				Thursday			
Time	Stage 1	Stage 2	Stage 3	Stage 4	Stage 1	Stage 2	Stage 3	Stage 4
00:00-02:00	13	13,2	13,2,6	13,2,6,3	4	4,15	4,15,12	4,15,12,14
02:00-04:00	5	5,9	5,9,8	5,9,8,11	2	2,13	2,13,3	2,13,3,16
04:00-06:00	15	15,4	15,4,14	15,4,14,12	10	10,7	10,7,11	10,7,11,6
06:00-08:00	11	11,6	11,6,18	11,6,18,2	5	5,9	5,9,19	5,9,19,8
08:00-10:00	4	4,15	4,15,21	4,15,21,3	16	16,3	16,3,17	16,3,17,7
10:00-12:00	10	10,7	10,7,22	10,7,22,9	15	15,4	15,4,21	15,4,21,14
12:00-14:00	12	12,8	12,8,24	12,8,24,1	13	13,2	13,2,23	13,2,23,6
14:00-16:00	2	2,13	2,13,23	2,13,23,11	8	8,12	8,12,24	8,12,24,5
16:00-18:00	3	3,16	3,16,17	3,16,17,4	7	7,10	7,10,22	7,10,22,16
18:00-20:00	9	9,5	9,5,19	9,5,19,10	14	14,1	14,1,20	14,1,20,15
20:00-22:00	1	1,14	1,14,20	1,14,20,12	6	6,11	6,11,18	6,11,18,13
22:00-00:00	7	7,10	7,10,16	7,10,16,2	9	9,5	9,5,1	9,5,1,15

	Friday				Saturday			
Time	Stage 1	Stage 2	Stage 3	Stage 4	Stage 1	Stage 2	Stage 3	Stage 4
00:00-02:00	6	6,11	6,11,13	6,11,13,2	3	3,16	3,16,4	3,16,4,15
02:00-04:00	16	16,3	16,3,7	16,3,7,4	12	12,8	12,8,2	12,8,2,14
04:00-06:00	14	14,1	14,1,15	14,1,15,9	11	11,6	11,6,10	11,6,10,13
06:00-08:00	3	3,16	3,16,17	3,16,17,10	15	15,4	15,4,21	15,4,21,5
08:00-10:00	1	1,14	1,14,20	1,14,20,11	7	7,10	7,10,22	7,10,22,13
10:00-12:00	12	12,8	12,8,24	12,8,24,2	14	14,1	14,1,20	14,1,20,8
12:00-14:00	9	9,5	9,5,19	9,5,19,4	6	6,11	6,11,18	6,11,18,16
14:00-16:00	10	10, 7	10,7,22	10,7,22,3	5	5,9	5,9,19	5,9,19,15
16:00-18:00	11	11,6	11,6,18	11,6,18,1	13	13,2	13,2,23	13,2,23,7
18:00-20:00	2	2,13	2,13,23	2,13,23,12	8	8,12	8,12,24	8,12,24,14
20:00-22:00	4	4,15	4,15,21	4,15,21,9	16	16,3	16,3,17	16,3,17,6
22:00-00:00	8	8,12	8,12,5	8,12,5,10	1	1,14	1,14,9	1,14,9,16

	Sunday			
Time	Stage 1	Stage 2	Stage 3	Stage 4
00:00-02:00	10	10,13	10,13,5	10,13,5,4
02:00-04:00	9	9,14	9,14,7	9,14,7,2
04:00-06:00	11	11,16	11,16,8	11,16,8,6
06:00-08:00	1	1,14	1,14,20	1,14,20,3
08:00-10:00	8	8,12	8,12,24	8,12,24,4
10:00-12:00	2	2,13	2,13,23	2,13,23,6
12:00-1400	7	7,10	7,10,22	7,10,22,5
14:00-16:00	3	3,16	3,16,17	3,16,17,1
16:00-18:00	4	4,15	4,15,21	4,15,21,8
18:00-20:00	6	6,11	6,11,18	6,11,18,2
20:00-22:00	5	5,9	5,9,19	5,9,19,7
22:00-00:00	12	12,15	12,15,1	12,15,1,3

Annex I – Calculation of a Curtailment Base Load Profile (CBL)

(informative)

I.1 Determining curtailment base load

A Curtailment Base Load profile (CBL) is created for every day of the week based on historic demand consumption. An average daily demand profile is created based on a half-hourly average of previous similar demand profile days.

The following options may be used to select historical demand data to determine CBL:

a) where a customers' operations are routine and the daily profiles are fairly repetitive, 3 previous "like" days may be used to determine a CBL. 3 week days may be used to determine a week day profile and 3 weekend days to determine a weekend profile;

b) a longer duration may also be utilised to determine the CBL. For example, 1, 2 or 3 month historical demand data;

c) where the customers' daily operations are similar, a single CBL day may be determined. Other options include a daily CBL for each of the 7 days of the week; a weekday and weekend CBL, etc.;

d) the CBL shall consist of average half-hourly profiles. These profiles shall exclude other curtailment days and Demand Response days for those participating in Demand response programs. A planned and unplanned maintenance day may be excluded for the purpose of CBL calculations; and

e) public holidays may be treated as a Saturday or Sunday.

The CBL should be updated at a frequency that takes into consideration the type of operation and the seasonal changes.

I.2 Performance Monitoring and Assessment Method

The relevant CBL is compared with the profile of the customer during the emergency declaration period. The difference in the profiles is used to calculate an average percentage reduction which is compared with the targets for the relevant load curtailment stages.

Load curtailment (LC) shall be calculated per the Integration Period, subtracting the Actual Load from the CBL and summated for the duration of the load curtailment request. The calculation is as follows:

$$LC = \text{sum}\ [(CBL\ (n) - \text{Actual Load}\ (n))\ldots\ldots(CBL\ (m) - \text{Actual Load}\ (m))]$$

where
n = first Integration Period of the Load Curtailment request
m = last Integration Period of the Load Curtailment request

If the Actual Load exceeds the CBL, the said difference shall be a negative variance and if the Actual Load is less than the CBL, the said difference shall be a positive variance. For each load curtailment event, the positive variances and the negative variances shall be summated.

For each Load curtailment event, the CBL shall be scaled up or down to match the Actual Load in proportion to the difference between the average of the CBL and the average Actual Load during the first 2 Integration Periods X(z) of a moving 3 completed Integration Periods immediately prior to the Load Reduction event.

Annex I
(concluded)

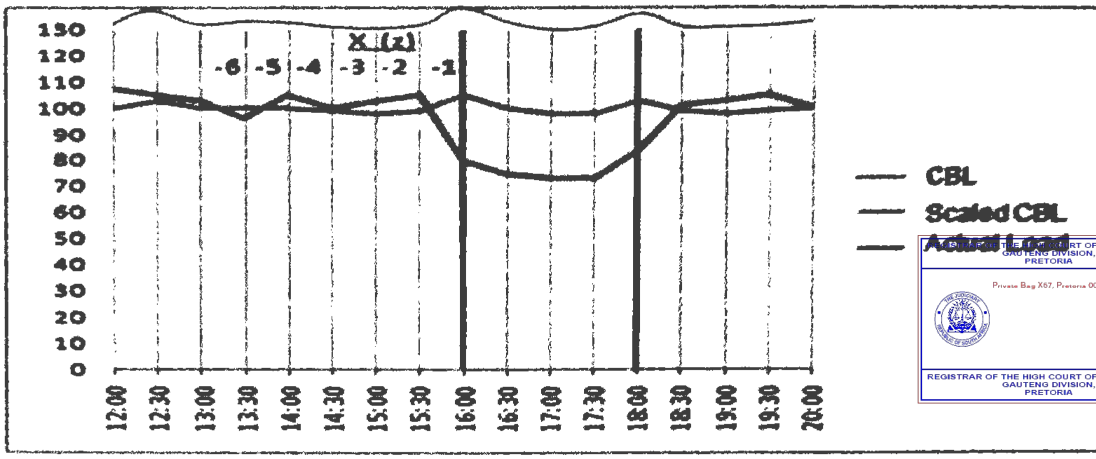


Figure H.1 — Curtailment base line measurement

The reference point X(z) may be moved to a mutually agreed period of normal consumption up to point -6, as indicated in the illustration. The allowed options for such a movement shall be limited to points (-1 and -2), (-3 and 4), (-4 and 5) or (-5 and 6).

Annex J – Design of contingency schedules
(normative)

J.1 Overview

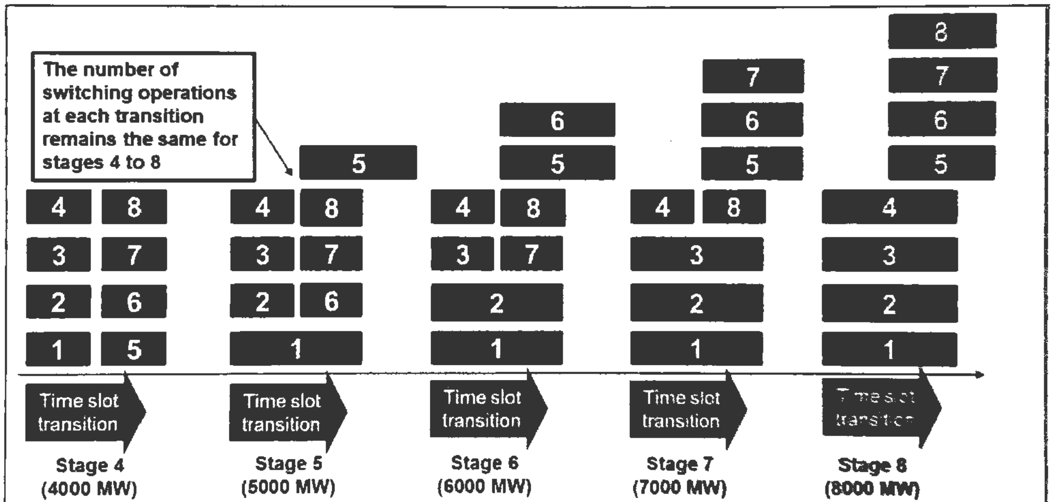
Contingency schedules are a requirement of this part of NRS048 in order to provide the System Operator with a controlled load reduction in the event of an extreme constraint (beyond Stages 1 to 4). The requirements below are normative, unless agreement has been reached with the System Operator for alternative approaches.

NOTE The implications of controlled switching at this level may significantly affect system frequency, and therefore the System Operator is required to approve and coordinate reduction regimes adopted by licensees.

J.2 Contingency schedule design

Licensees shall prepare extended load shedding schedules (Stages 5 to 8) based on a doubling of the time-slots for each block related to the respective load shedding stages (illustrated in figure J.1)

NOTE Whilst Stage 4 shedding provides up to approximately 4000 MW of load reduction, the reduction provided by contingency schedules is doubled to 8000 MW in 1000 MW increments from Stages 5 to 8.



NOTE 1 Each numbered block represents the customers shed in the time slot. For illustrative purposes, Stage 1 shedding would typically be block 1 followed by block 5 in the next time slot. Stage 2 shedding would be blocks 1 and 2 followed by blocks 5 and 6. Stage 4 shedding would be blocks 1 to 4 followed by blocks 5 to 8. Stage 5 would double the time for which blocks 1 and 5 are shed, but their start times remain the same. This means that blocks 1 and 5 overlap, contributing to the additional 1000 MW at a national level.

NOTE 2 In this illustrative example, customers on a 2 hr schedule will experience load shedding for a period of 4 hrs, with the interruption in supply being initiated at approximately the same time as indicated in the Stage 4 schedule.

NOTE 3 The actual transition times may be staggered.

Figure J.1 — Illustration of contingency schedules based on progressively extended switching durations from Stage 5 (one block interrupted for double the time) to Stage 8 (all blocks interrupted for double the time)

Annex J
(concluded)

The design shall be implemented as follows:

a) **stage 5 schedules** shall be the same as Stage 4 schedules with the exception that blocks shed under Stage 1 are doubled in time (e.g. 2 hr time slots become 4 hr slots).

b) **stage 6 schedules** shall be the same as Stage 4 schedules with the exception that blocks shed under Stage 1 and 2 are doubled in time (e.g. 2 hr time slots become 4 hr slots).

c) **stage 7 schedules** shall be the same as Stage 4 schedules with the exception that blocks shed under Stage 1, 2, and 3 are doubled in time (e.g. 2 hr time slots become 4 hrs slots).

d) **stage 8 schedules** shall be the same as Stage 4 schedules with the exception that all blocks shed are doubled in time (e.g. 2 hr time slots become 4 hrs slots).

Annex K – 16 Block rotating schedule for a standard month

(informative)

K.1 Overview

Typical model load shedding schedules are shown in this annex, based on the 16 blocks identified for the load shedding schedules. The model schedules provided address load shedding periods of 2hrs (figure K.1), 3hrs (figure K.2), and 4hrs (figure K.3).

Licensees may use these model schedules to generate their own schedules based on the normative requirements in sections 1 to 10 of this Code.

K.2 Methodology

The assumption made in the examples provided is that the base load has been divided into 16 equal blocks, of just more than 6% of the base load each. These are then rotated across the day, over all 24 hours, and all 7 days of the week. The pattern is repeated until the 31st day, to establish a standard pattern for each month. The pattern begins again on day 1 of each month and runs until the end of the month, be it a 28 day, 30 day or 31 day month.

Table K.1- pattern of 16 2hour block schedule rotated through 31 days
The blocks are listed per stage per day, and accumulate as the stages increase. In other words:

- **Stage 1 consists of the Stage 1 listed block**
- **Stage 2 consists of the Stage 2 and 1 listed block,**
- **Stage 3 consists of the Stage 3, 2 and 1 listed blocks and**
- **Stage 4 consists of the Stage 4, 3, 2 and 1 listed blocks.**

Time	Blocks per stage	Day of the month, repeating at the end of the month, not rolling over																														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
00:00-02:30	1	1	13	9	5	2	14	10	6	3	15	11	7	4	16	12	8	5	1	13	9	6	2	14	10	7	3	15	11	8	4	16
	2	5	1	13	9	6	2	14	10	7	3	15	11	8	4	16	12	9	5	1	13	10	6	2	14	11	7	3	15	12	8	4
	3	[illegible]	[illegible]	1	13	10	6	2	14	11	7	[illegible]	15	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
02:00-04:30	1	2	14	10	6	3	15	11	7	4	16	12	8	5	1	13	9	6	2	14	10	7	3	15	11	8	4	16	12	9	5	1
	2	6	2	14	10	7	3	15	11	8	4	16	12	9	5	1	13	10	6	2	14	11	7	3	15	12	8	4	16	13	9	5
	3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

0302

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA GAUTENG DIVISION, PRETORIA

Annex K
(continued)

04:00-06:30	1		3	15	11	7	4	16	12	8	5	1	13	9	6	2	14	10	7	3	15	11	8	4	16	12	9	5	1	13	10	6	2
	2		7	3	15	11	8	4	16	12	9	5	1	13	10	6	2	14	11	7	3	15	12	8	4	16	13	9	5	1	14	10	6
	3		11	7	3	15	12	8	4	16	13	9	5	1	14	10	6	2	15	11	7	3	16	12	8	4	1	13	9	5	2	14	10
	4		15	11	7	3	16	12	8	4	1	13	9	5	2	14	10	6	3	15	11	7	4	16	12	8	5	1	13	9	6	2	14
06:00-08:30	1		4	16	12	8	5	1	13	9	6	2	14	10	7	3	15	11	8	4	16	12	9	5	1	13	10	6	2	14	11	7	3
	2		8	4	16	12	9	5	1	13	10	6	2	14	11	7	3	15	12	8	4	16	13	9	5	1	14	10	6	2	15	11	7
	3		12	8	4	16	13	9	5	1	14	10	6	2	15	11	7	3	16	12	8	4	1	13	9	5	2	14	10	6	3	15	11
	4		16	12	8	4	1	13	9	5	2	14	10	6	3	15	11	7	4	16	12	8	5	1	13	9	6	2	14	10	7	3	15
08:00-10:30	1		5	1	13	9	6	2	14	10	7	3	15	11	8	4	16	12	9	5	1	13	10	6	2	14	11	7	3	15	12	8	4
	2		9	5	1	13	10	6	2	14	11	7	3	15	12	8	4	16	13	9	5	1	14	10	6	2	15	11	7	3	16	12	8
	3		13	9	5	1	14	10	6	2	15	11	7	3	16	12	8	4	1	13	9	5	2	14	10	6	3	15	11	7	4	16	12
	4		1	13	9	5	2	14	10	6	3	15	11	7	4	16	12	8	5	1	13	9	6	2	14	10	7	3	15	11	8	4	16
10:00-12:30	1		6	2	14	10	7	3	15	11	8	4	16	12	9	5	1	13	10	6	2	14	11	7	3	15	12	8	4	16	13	9	5
	2		10	6	2	14	11	7	3	15	12	8	4	16	13	9	5	1	14	10	6	2	15	11	7	3	16	12	8	4	1	13	9
	3		14	10	6	2	15	11	7	3	16	12	8	4	1	13	9	5	2	14	10	6	3	15	11	7	4	16	12	8	5	1	13
	4		2	14	10	6	3	15	11	7	4	16	12	8	5	1	13	9	6	2	14	10	7	3	15	11	8	4	16	12	9	5	1
12:00-14:30	1		7	3	15	11	8	4	16	12	9	5	1	13	10	6	2	14	11	7	3	15	12	8	4	16	13	9	5	1	14	10	6
	2		11	7	3	15	12	8	4	16	13	9	5	1	14	10	6	2	15	11	7	3	16	12	8	4	1	13	9	5	2	14	10
	3		15	11	7	3	16	12	8	4	1	13	9	5	2	14	10	6	3	15	11	7	4	16	12	8	5	1	13	9	6	2	14
	4		3	15	11	7	4	16	12	8	5	1	13	9	6	2	14	10	7	3	15	11	8	4	16	12	9	5	1	13	10	6	2
14:00-16:30	1		8	4	16	12	9	5	1	13	10	6	2	14	11	7	3	15	12	8	4	16	13	9	5	1	14	10	6	2	15	11	7
	2		12	8	4	16	13	9	5	1	14	10	6	2	15	11	7	3	16	12	8	4	1	13	9	5	2	14	10	6	3	15	11
	3		16	12	8	4	1	13	9	5	2	14	10	6	3	15	11	7	4	16	12	8	5	1	13	9	6	2	14	10	7	3	15
	4		4	16	12	8	5	1	13	9	6	2	14	10	7	3	15	11	8	4	16	12	9	5	1	13	10	6	2	14	11	7	3

0303

Annex K
(continued)

16:00-18:30	1		9	5	1	13	10	6	2	14	11	7	3	15	12	8	4	16	13	9	5	1	14	10	6	2	15	11	7	3	16	12	8
	2		13	9	5	1	14	10	6	2	15	11	7	3	16	12	8	4	1	13	9	5	2	14	10	6	3	15	11	7	4	16	12
	3		1	13	9	5	2	14	10	6	3	15	11	7	4	16	12	8	5	1	13	9	6	2	14	10	7	3	15	11	8	4	16
	4		5	1	13	9	6	2	14	10	7	3	15	11	8	4	16	12	9	5	1	13	10	6	2	14	11	7	3	15	12	8	[illegible]
[illegible]	1		10	6	2	14	11	7	3	15	12	8	4	16	13	9	5	1	14	10	6	2	15	11	7	3	16	12	8	4	1	13	9
	2		14	10	6	2	15	11	7	3	16	12	8	4	1	13	9	5	2	14	10	6	3	15	11	7	4	16	12	8	5	1	13
	3		2	14	10	6	3	15	11	7	4	16	12	8	5	1	13	9	6	2	14	10	7	3	15	11	8	4	16	12	9	5	1
	4		6	2	14	10	7	3	15	11	8	4	16	12	9	5	1	13	10	6	2	14	11	7	3	15	12	8	4	16	[illegible]	[illegible]	[illegible]
20:00-22:[illegible]	1		11	7	3	15	12	8	4	16	13	9	5	1	14	10	6	2	15	11	7	3	16	12	8	4	1	13	9	5	2	14	10
	2		15	11	7	3	16	12	8	4	1	13	9	5	2	14	10	6	3	15	11	7	4	16	12	8	5	1	13	9	6	2	14
	3		3	15	11	7	4	16	12	8	5	1	13	9	6	2	14	10	7	3	15	11	8	4	16	12	9	5	1	13	10	6	2
	4		7	3	15	11	8	4	16	12	9	5	1	13	10	6	2	14	11	7	3	15	12	8	4	16	13	9	5	[illegible]	[illegible]	[illegible]	[illegible]
22:00-00:30	1		12	8	4	16	13	9	5	1	14	10	6	2	15	11	7	3	16	12	8	4	1	13	9	5	2	14	10	6	3	15	11
	2		16	12	8	4	1	13	9	5	2	14	10	6	3	15	11	7	4	16	12	8	5	1	13	9	6	2	14	10	7	3	15
	3		4	16	12	8	5	1	13	9	6	2	14	10	7	3	15	11	8	4	16	12	9	5	1	13	10	6	2	14	11	7	3
	4		8	4	16	12	9	5	1	13	10	6	2	14	11	7	3	15	12	8	4	16	13	9	5	1	14	10	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

0304

Annex K
(continued)

Table K.2 — Pattern of 16 4hour block schedule rotated through 31 days. The blocks are listed per stage per day, and accumulate as the stages increase as per table K.1

Time		[illegible] month, repeating at the end of the month, not rolling over																														
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
00:00:00	1	1	7	13	3	9	15	5	11	2	8	14	4	10	16	6	12	3	9	15	5	11	1	7	13	4	10	16	6	12	2	8
	2	5	11	1	7	13	3	9	15	6	12	2	8	14	4	10	16	7	13	3	9	15	5	11	1	8	14	4	10	16	6	12
	3	9	15	5	11	1	7	13	3	10	16	6	12	2	8	14	4	11	1	7	13	3	9	15	5	12	2	8	14	4	10	16
04:00:00	1	2	8	14	4	10	16	6	12	3	9	15	5	11	1	7	13	4	10	16	6	12	2	8	14	5	11	1	7	13	3	9
	2	6	12	2	8	14	4	10	16	7	13	3	9	15	5	11	1	8	14	4	10	16	6	12	2	9	15	5	11	1	7	13
	3	10	16	6	12	2	8	14	4	11	1	7	13	3	9	15	5	12	2	8	14	4	10	16	6	13	3	9	15	5	11	[illegible]
08:00:00	1	3	9	15	5	11	1	7	13	4	10	16	6	12	2	8	14	5	11	1	7	13	3	9	15	6	12	2	8	14	4	10
	2	7	13	3	9	15	5	11	1	8	14	4	10	16	6	12	2	9	15	5	11	1	7	13	3	10	16	6	12	2	8	14
	3	11	1	7	13	3	9	15	5	12	2	8	14	4	10	16	6	13	3	9	15	5	11	1	7	14	4	10	16	6	12	2
12:00:00	1	4	10	16	6	12	2	8	14	5	11	1	7	13	3	9	15	6	12	2	8	14	4	10	16	7	13	3	9	15	5	11
	2	8	14	4	10	16	6	12	2	9	15	5	11	1	7	13	3	10	16	6	12	2	8	14	4	11	1	7	13	3	9	15
	3	12	2	8	14	4	10	16	6	13	3	9	15	5	11	1	7	14	4	10	16	6	12	2	8	15	5	11	1	7	13	[illegible]
16:00:00	1	5	11	1	7	13	3	9	15	6	12	2	8	14	4	10	16	7	13	3	9	15	5	11	1	8	14	4	10	16	6	12
	2	9	15	5	11	1	7	13	3	10	16	6	12	2	8	14	4	11	1	7	13	3	9	15	5	12	2	8	14	4	10	16
	3	13	3	9	15	5	11	1	7	14	4	10	16	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

0305

Annex K
(concluded)

	1	6	12	2	8	14	4	10	16	7	13	3	9	15	5	11	1	8	14	4	10	16	6	12	2	9	15	5	11	1	7	13
20:00:00	2	10	16	6	12	2	8	14	4	11	1	7	13	3	9	15	5	12	2	8	14	4	10	16	6	13	3	9	15	5	11	1
	3	14	4	10	16	6	12	2	8	15	5	11	1	7	13	3	9	16	6	12	2	8	14	[illegible]	10	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	15	[illegible]

0306

Bibliography

NRS 086, *Centralized load control systems.*

IN THE HIGH COURT OF SOUTH AFRICA

GAUTENG DIVISION, PRETORIA

Case no: ____________

In the matter between:

SAKELIGA NPC	**1st Applicant**
AGRI NORTH WEST	**2nd Applicant**
TLU SA	**3rd Applicant**
MAGALIESBERG CITRUS COMPANY (PTY) LTD	**4th Applicant**

and

ESKOM HOLDINGS SOC LTD	**1st Respondent**
THE NATIONAL ENERGY REGULATOR OF SOUTH AFRICA (NERSA)	**2nd Respondent**
THE MINISTER OF MINERAL RESOURCES AND ENERGY	**3rd Respondent**

CONFIRMATORY AFFIDAVIT

I, the undersigned,

PHILIPPUS DU TOIT

M.T

Do hereby confirm under oath that:

1 I am a major male, and the chief executive for the 2nd applicant, duly appointed and authorised by its executive committee.

2 The facts deposed to herein fall within my personal knowledge, unless the context indicates otherwise, and are to the best of my belief both true and correct.

3 I have read the founding affidavit of TOBIAS VIVIAN ALBERTS, which I on behalf of the 2nd applicant support, and confirm that the content thereof is both true and correct in as far as it relates to me and the 2nd applicant.

DEPONENT

I HEREBY CERTIFY THAT THE DEPONENT HAS ACKNOWLEDGED:

(a) he/she knows and understands the contents of this affidavit;

(b) he/she has no objection to taking an oath;

(c) he/she considers the oath to be binding on his/her conscience.

THUS signed and sworn before me, at Jeeruft on this the 21 day of 12 **2022**, the Regulations contained in Government Notice No. R1648 of 19 August 1977 (as amended) having been fully complied with.

M.G

91/07017-3

Mmagwgosi

COMMISSIONER OF OATHS

FULL NAMES: MATLHOMOLA T. MABELWA

BUSINESS ADDRESS: 01 GERRIT MARITZ STR ZEERUST

DESIGNATION: CST

TIRELO YA MAPODISI A AFRIKA BORWA
COMMUNITY SERVICE CENTRE
2022 -12- 21
ZEERUST
SUID AFRIKAANSE POLISIEDIENS
SOUTH AFRICAN POLICE SERVICE

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA
Private Bag X67, Pretoria 0001
REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA

IN THE HIGH COURT OF SOUTH AFRICA

GAUTENG DIVISION, PRETORIA

Case no: ______________

In the matter between:

SAKELIGA NPC	**1st Applicant**
AGRI NORTH WEST	**2nd Applicant**
TLU SA	**3rd Applicant**
MAGALIESBERG CITRUS COMPANY (PTY) LTD	**4th Applicant**

and

ESKOM HOLDINGS SOC LTD	**1st Respondent**
THE NATIONAL ENERGY REGULATOR OF SOUTH AFRICA (NERSA)	**2nd Respondent**
THE MINISTER OF MINERAL RESOURCES AND ENERGY	**3rd Respondent**

SUPPORTING AFFIDAVIT

I, the undersigned,

GABRIEL JACOBUS LÖTTER

Do hereby state under oath that:

1 I am a major male, and the head of services and trauma for the 3rd applicant, duly appointed and authorised by its executive committee.

2 The facts deposed to herein fall within my personal knowledge, unless the context indicates otherwise, and are to the best of my belief both true and correct.

3 I have read the founding affidavit of TOBIAS VIVIAN ALBERTS, which I on behalf of the 3rd applicant support, and confirm that the content thereof is both true and correct in as far as it relates to me and the 3rd applicant.

DEPONENT

I HEREBY CERTIFY THAT THE DEPONENT HAS ACKNOWLEDGED:

(a) He knows and understands the contents of this affidavit;
(b) He has no objection to taking an oath;
(c) He considers the oath to be binding on his conscience.

THUS signed and sworn before me, at **Pretoria** on this the 21 day of **December 2022**, the Regulations contained in Government Notice No. R1648 of 19 August 1977 (as amended) having been fully complied with.

COMMISSIONER OF OATHS
FULL NAMES:
BUSINESS ADDRESS:
DESIGNATION:

PIET HENDRIK SCHALK BEZUIDENHOUT
BOTHA BEZUIDENHOUT ATTORNEYS
Commissioner of Oaths
Practising Attorney (RSA)
HB Forum, 13 Stamvrug Street
Val de Grace, Pretoria

IN THE HIGH COURT OF SOUTH AFRICA

GAUTENG DIVISION, PRETORIA

Case no: ____________

In the matter between:

SAKELIGA NPC	**1st Applicant**
AGRI NORTH WEST	**2nd Applicant**
TLU SA	**3rd Applicant**
MAGALIESBERG CITRUS COMPANY (PTY) LTD	**4th Applicant**

and

ESKOM HOLDINGS SOC LTD	**1st Respondent**
THE NATIONAL ENERGY REGULATOR OF SOUTH AFRICA (NERSA)	**2nd Respondent**
THE MINISTER OF MINERAL RESOURCES AND ENERGY	**3rd Respondent**

CONFIRMATORY AFFIDAVIT

I, the undersigned,

HENDRIK NAUDE PIENAAR

L. C

Do hereby confirm under oath that:

1 I am a major male, and the general manager for the 2nd applicant, duly appointed and authorised by its executive committee.

2 The facts deposed to herein fall within my personal knowledge, unless the context indicates otherwise, and are to the best of my belief both true and correct.

3 I have read the founding affidavit of TOBIAS VIVIAN ALBERTS, which I on behalf of the 2nd applicant support, and confirm that the content thereof is both true and correct in as far as it relates to me and the 2nd applicant.

DEPONENT

I HEREBY CERTIFY THAT THE DEPONENT HAS ACKNOWLEDGED:

(a) he/she knows and understands the contents of this affidavit;

(b) he/she has no objection to taking an oath;

(c) he/she considers the oath to be binding on his/her conscience.

THUS signed and sworn before me, at OTTOSHOOP on this the 21 day of 12 **2022**, the Regulations contained in Government Notice No. R1648 of 19 August 1977 (as amended) having been fully complied with.

L.C

72133571
CST
VAN ROOYEN L.C

COMMISSIONER OF OATHS

FULL NAMES: L.C Van Rooyen

BUSINESS ADDRESS: 01 Commissioner Street, Ottoshoop, 2866

DESIGNATION: Constable

TIRO YA MAPODISI A AFRIKA BORWA
STATION COMMANDER
2022 -12- 21
OTTOSHOOP
SUID AFRIKAANSE POLISIEDIENS
SOUTH AFRICAN POLICE SERVICE

REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA
Private Bag X67, Pretoria 0001
REGISTRAR OF THE HIGH COURT OF SOUTH AFRICA
GAUTENG DIVISION,
PRETORIA

L.C