NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

Decision and Reasons for Decision (RfD)

In the matter regarding the

Licensee Tariff Redetermination Application for the 2024/25 Financial Year

By

City Power

THE DECISION

1. At its meeting held on 7 September 2026, the Regulator Executive Committee (REC) considered City Power's tariff application. Based on the facts and evidence presented, the REC approved the tariff increases for the 2024/25 financial year as set out in the tariff analysis section of this document.

2. Based on the available information and the analysis performed, the REC decided:
   a) to approve the redetermination tariffs that are based on the Cost of Supply (COS) study as recommended in the tariff analysis section for implementation by the licensee with effect from 1 July 2024;
   b) to note the COS study submitted by the licensee;
   c) that the municipality must submit a report accounting for all the costs that have been noted in its COS study, to enable the National Energy Regulator of South Africa (NERSA) to perform its independent verification/audit process;
   d) that the licensee must submit a quarterly smart efficiency plan with improvement measures identified for reducing high energy losses and submit it by 31 January 2027; and
   e) that the licensee must undertake independent verification and valuation of its electricity distribution assets and establish a verified Regulatory Asset Base (RAB) with a clearly defined baseline year. The verified asset register and supporting valuation report must be submitted to NERSA with the 2027/28 tariff

application. The verified RAB must distinguish between assets that are used and useful, fully depreciated, or no longer in service, and the municipality must demonstrate that the depreciation allowance is based solely on the verified remaining depreciable value of the regulated assets.

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ABBREVIATIONS AND ACRONYMS

CoS	Cost of Supply
CPI	Consumer Price Index
D-Form	Distribution form
ERA	Electricity Regulation Act
EPP	Electricity Pricing Policy
FBE	Free Basic Electricity
Kd	Cost of Debt
Ke	Cost of Equity
NERA	National Energy Regulator Act
NERSA	National Energy Regulator of South Africa
OPEX	Operating Expenditure
RAB	Regulatory Asset Base
WACC	Weighted Average Cost of Capital

1. INTRODUCTION

1.1. The National Energy Regulator of South Africa (NERSA), in accordance with its statutory mandate, regulates electricity prices and tariffs and assesses tariff applications submitted by licensees on an annual basis. As part of this process, NERSA must approve municipal electricity tariffs prior to their implementation, which takes effect on 1 July of each financial year.

1.2. City Power is located in Gauteng and has an electricity sales profile largely driven by industrial customers, which contributed 47% of total electricity sales in the 2022/23 financial year, while domestic customers accounted for 34%.

1.3. The Licensee provides 50 kWh of Free Basic Electricity (FBE) per month to registered indigent customers, in line with national policy objectives to ensure access to basic energy services for low-income households. Detailed customer statistics and consumption patterns are shown in Table 1 below.

Table 1: Customer statistics (data obtained from the latest D-forms – 2022/23 FY)

Customer categories	***MWh***	***% MWh***	***Customer numbers***
Domestic(Prepaid)	667 539	9%	119 355
Domestic(Conventional)	1 794 952	25%	99 080
Agriculture	36 187	1%	24
Manufacturing	3 360 022	47%	3820
Commercial Prepaid	75 680	1%	3 166
Commercial Conventional	572 197	8%	10 415
Own use	239 503	3%	1
Other consumers(resellers)	328 600	5%	1179
TOTAL	**7 074 680**	**100%**	**237 040**
FBE	3663	0,15%	6106

1.4. NERSA received the Licensee's tariff application, together with its Cost of Supply (CoS) study, on 13 March 2026. The Licensee subsequently revised the CoS study and resubmitted it on 27 March 2026.

1.5. The Licensee's application was based on a Regulatory Asset Base (RAB) derived from a replacement cost valuation undertaken for insurance purposes in the 2022/23 financial year. The asset values were indexed using the Consumer Price Index (CPI) to determine the values applicable to the 2024/25 financial year and were subsequently used to calculate both depreciation and the Return on Assets (ROA) included in the tariff application. The approach adopted by the Licensee is consistent with key principles of a Rate of Return methodology.

1.6. The Licensee applied for an average price increase of 12.72% for the tariff redetermination for the 2024/25 financial year.

1.7. NERSA followed the notice and comment consultation process and considered oral presentations. City Power's tariff application was published on the NERSA website on 7 April 2026, as well as on social media platforms and in local and national newspapers to solicit written comments from affected parties.

1.8. NERSA's decision was made on 7 September 2026, taking into consideration the written comments received from affected stakeholders and the analysis conducted by NERSA.

2. LEGAL AND REGULATORY FRAMEWORK

NERSA's Statutory Mandate

2.1. NERSA is established as a juristic person in terms of section 3 of the National Energy Regulator Act, 2004 (Act No. 40 of 2004) ('the NERA'). In terms of section 4 of the NERA, NERSA, as the decision-making body, must regulate the electricity industry and execute the functions set out in the Electricity Regulation Act, 2006 (Act No. 4 of 2006) ('the ERA').

2.2. NERSA's electricity regulatory mandate is therefore primarily governed by the ERA. Section 3 of the ERA particularly provides that NERSA is the custodian and enforcer of the national electricity regulatory framework.

2.3. NERSA's mandate includes the regulation and approval of electricity tariffs, the imposition and enforcement of licence conditions, and oversight of licensed electricity distributors, including municipalities.

Tariff Determination Framework

2.4. The determination and approval of electricity tariffs is governed by section 15(1) of the ERA, which requires that tariffs enable cost recovery, provide a reasonable return, avoid undue discrimination, and may include cross-subsidisation and efficiency incentives.

2.5. These principles are supplemented by the Electricity Pricing Policy (EPP), which requires tariffs to be cost reflective, transparent and economically efficient, and supported by COS studies conducted in accordance with approved methodologies.

Administrative Law Requirements

2.6. The determination of municipal electricity tariffs constitutes administrative action under the Promotion of Administrative Justice Act,2000 (Act No. 3 of 2000) ('PAJA'); as such, NERSA must ensure that decisions are lawful, reasonable and procedurally fair.

2.7. To this end, meaningful public participation must be undertaken, ensuring that affected stakeholders are afforded an opportunity to make representations prior to final decision-making.

Judicial Intervention and the Redetermination Process

2.8. On or about 15 November 2024, NERSA received a judicial review application in relation to the approval of the 2024/25 FY municipal electricity tariffs applicable to City Power and City of Johannesburg (CoJ). In those proceedings, the relief sought was the review, setting aside and remittal of the tariff approval decision.

2.9. The issues raised in the court papers can be summarised as follows. Firstly, it is alleged there were procedural deficiencies and unfairness in the process. The CoJ's CoS study was not made available to the public, and it is said that NERSA did not afford the public a proper opportunity to make meaningful representations. As a result, NERSA's determination of the COJ electricity tariffs for the 2024/25 period is alleged to have been procedurally flawed, unfair and unlawful.

2.10. Secondly, it is contended that NERSA relied on irrelevant considerations and reached an irrational decision. Specifically, NERSA is said to have lacked the necessary relevant information, which suggests that the approval of COJ's application was rushed and based on outdated benchmarking or assumption methods. In light of these shortcomings, the decision was argued to have been irrational, as it failed to strike an appropriate balance between the interests of the COJ, electricity end users and the need to protect both present and future customers.

2.11. On 14 January 2026, the High Court of South Africa (Gauteng Division, Pretoria) reviewed and set aside the tariff approval decision for the 2024/25 financial year and directed NERSA to undertake a redetermination process by 30 June 2026. The court order further required NERSA to ensure that the CoJ's CoS study and supporting information are made available to interested and affected parties, that a reasonable opportunity is afforded for public participation and the submission of representations, and that the redetermination process is undertaken in accordance with the applicable legal and regulatory framework.

2.12. In compliance with the court order, NERSA initiated the redetermination process. This process included the publication of the CoS study and supporting information, the invitation of written comments, the conducting of public hearings, the consideration of submissions received from interested and affected parties and the reassessment of the tariff application based on the information placed before NERSA. The purpose of the redetermination process is to enable NERSA to make a lawful, reasonable and procedurally fair tariff determination supported by adequate information and clear reasons.

2.13. In terms of sections 4(a)(ii), 14 and 15 of the ERA, NERSA is empowered and obliged to determine and approve electricity tariffs for licensed electricity distributors. The annual determination of municipal electricity tariffs constitutes a prospective regulatory function intended to ensure the continued financial and operational sustainability of licensed distributors and the continued provision of electricity services.

2.14. In addition, sections 74(2)(d) and (e) of the Local Government: Municipal Systems Act, 2000 (Act No. 32 of 2000) ('MSA') require municipal tariff policies to promote the financial sustainability of municipal services and the efficient, effective and sustainable delivery of those services. In determining tariffs, NERSA must apply the principles contemplated in section 15 of the ERA, to give due consideration to the EPP, particularly policy positions 1, 2 and 23.

2.15. The EPP emphasises principles of cost reflectivity, revenue adequacy and the recovery of efficiently incurred costs as fundamental to the sustainable provision of electricity supply services. NERSA's annual prospective determination of municipal electricity tariffs accordingly enables municipalities to comply with their statutory obligations under sections 74(2)(d) and (e) of the MSA.

City Power and City of Johannesburg

2.16. The Court declared the 2024/25 financial year tariff approvals unlawful and set them aside with immediate effect. The Court further directed NERSA to undertake a tariff redetermination process, which was initially required to be finalised by 30 June 2026. Following an application for an extension, the Court subsequently varied the order on 21 July 2026, extending the deadline to 30 September 2026.

2.17. The Court further prescribed a structured process including resubmission of applications, publication, public participation and final determination within defined timelines, together with interim default tariff mechanisms.

2.18. In undertaking the redetermination process, NERSA considered the information submitted by the Licensee pursuant to the court order, the applicable legislative

and policy framework, representations received during the public participation process and the need to arrive at a lawful and reasonable tariff determination based on the information before it.

Legal Effect of the Court Orders

2.19. The court orders constitute binding orders of the Court. The previous tariff approval decisions were reviewed and set aside, and NERSA was directed to undertake a redetermination process. Pending such redetermination, the interim tariff is governed by the provisions of the court order.

Conclusion

2.20. The reasons set out below record the basis on which NERSA undertook the court-directed redetermination process and reached the decision in respect of the 2024/25 FY municipal tariffs for City Power.

3. FINANCIAL AND TECHNICAL PERFORMANCE

3.1. Level of Reliability of Information

3.1.1 In evaluating the financial and technical performance of City Power, the assessment was based on the 2022/23 FY Distribution forms (D-forms) submitted with the tariff application. The data was verified against supporting documents, including the Trial Balance and audited Annual Financial Statement, and is therefore considered reliable for tariff analysis purposes. The audited Annual Financial Statements (AFS) relate to City Power's electricity distribution operations and not to the broader operations of the City of Johannesburg.

3.1.2 Table 2 below shows City Power’s technical and financial performance.

Table 2: Technical and financial performance

Performance Indicators	2021/22 FY	2022/23 FY
Percentage surplus/(Deficit): %	-4,69	-15,28
Energy Losses: %	27,87	27,20

3.2. **Percentage Surplus**

3.2.1. City Power recorded operating deficits in both the 2021/22 FY and 2022/23 financial years. The percentage deficit increased from 4,69% in the 2021/22 FY to 15,28% in the 2022/23 FY, indicating a deterioration in the financial performance of the electricity undertaking. The increase in the deficit suggests that expenditure growth continued to outpace revenue generated from electricity operations, resulting in insufficient revenue to fully recover the costs associated with providing the service.

3.2.2. The persistent operating deficits raise concerns regarding the financial sustainability of the electricity business and may be indicative of underlying challenges such as escalating operating costs, inadequate tariff levels, high energy losses, revenue collection inefficiencies, or a combination thereof. If not adequately addressed, continued deficits may constrain the Licensee's ability to maintain and expand infrastructure, fund asset replacement programmes, and ensure the long-term reliability and quality of electricity supply. NERSA notes that the reported financial information was verified against the audited AFS.

3.3. **Energy Losses**

3.3.1. City Power reported energy losses of 27.87% in the 2021/22 financial year and 27.20% in the 2022/23 financial year. While this reflects a marginal improvement of 0.67%, the level of energy loss remains substantially high. The persistently high losses suggest ongoing inefficiencies within the electricity distribution network and may be indicative of significant non-technical losses arising from electricity theft, inaccurate metering and billing-related deficiencies.

3.3.2. Table 3 below presents a revenue impact analysis under three energy loss scenarios to assess the effect of energy losses on the financial performance of the electricity undertaking, namely:

a) the actual losses of 27.20%, representing the current operating position;
b) a reduced loss level of 12%, reflecting an efficient and regulatory-aligned scenario, for assessment purposes; and
c) energy losses of 6%, reflecting an improved efficiency scenario for assessment purposes.

Table 3: Assessment of energy losses and revenue impact – 2024/25 FY

	D-Form Input	Energy Loss@12%	Energy Loss@6%
Average Selling Price	243,33		
Sales kWh	7 074 680 281,00	8 551 466 790,24	9 134 521 344,12
Purchases kWh	9 717 575 898,00	9 717 575 898,00	9 717 575 898,00
Losses kWh	2 642 895 617,00	1 166 109 107,76	583 054 553,88
Losses percentage	**27,20%**	**12,00%**	**6,00%**
Additional Energy (kWh)		1 476 786 509,24	2 059 841 063,12
Additional Revenue (Rands)		3 593 412 501,31	5 012 138 572,91
	D-Form Input	Energy Loss@12%	Energy Loss@6%
Total Revenue (Rands)	R 17 542 126 000,00	R 21 135 538 501,31	R 22 554 264 572,91
Total Expenses (Rands)	R 20 223 369 000,00	R 20 223 369 000,00	R 20 223 369 000,00
Net Profit (Loss)	R -2 681 243 000,00	R 912 169 501,31	R 2 330 895 572,91
Percentage Surplus/Deficit	**-15,28%**	**4,32%**	**10,33%**

3.3.3. The Licensee reported energy losses of 27,20%, equivalent to 2 642 895 617 kWh, based on electricity purchases of 9 717 575 898 kWh. NERSA notes that the reported losses are significantly above prudent levels and have a material impact on the financial sustainability of the electricity undertaking.

3.3.4. A sensitivity analysis was undertaken to assess the financial impact of reducing losses to 12% and 6%. The analysis indicates that, at a 12% loss level, the electricity business would generate a surplus of R912 169 501 (4,32%), while a 6% loss level would result in a surplus of R2 330 895 573 (10,33%). In contrast, the D-Form submission reflects a deficit of R2 681 243 000 (15,28%).

3.3.5. The analysis demonstrates that excessive technical and non-technical losses are a significant contributor to the financial challenges experienced by the electricity undertaking. NERSA is therefore of the view that City Power should prioritise the implementation of effective loss-reduction measures, including network refurbishment, revenue protection initiatives, improved metering and reducing illegal connections. Sustainable reductions in energy losses would improve the financial performance of the electricity business and reduce the reliance on tariff increases to restore financial viability.

3.4. **General conclusion on the financial and technical indicators**

3.4.1. NERSA notes that City Power's continued operating deficits and high energy losses place pressure on the financial sustainability of the electricity business. The analysis indicates that reducing technical and non-technical losses could significantly improve financial performance. NERSA therefore encourages City

Power to implement effective loss-reduction initiatives and improve operational efficiency to support a financially sustainable and cost-reflective electricity service.

4. DETERMINATION OF CITY POWER'S TARIFFS BASED ON THE COST OF SUPPLY (COS) STUDY

4.1. The analysis that NERSA performed in considering and approving City Power's tariff application was supported by a cost of supply study.

4.2. City Power utilised the revised CoS study model to determine its revenue requirement for the 2024/25 financial year and to allocate costs among customer classes in a fair and equitable manner. The CoS study was conducted in accordance with the NERSA CoS Framework and was based on the latest available audited financial information for the 2022/23 financial year.

4.3. Figure 1 below details the five steps considered in determining the COS.

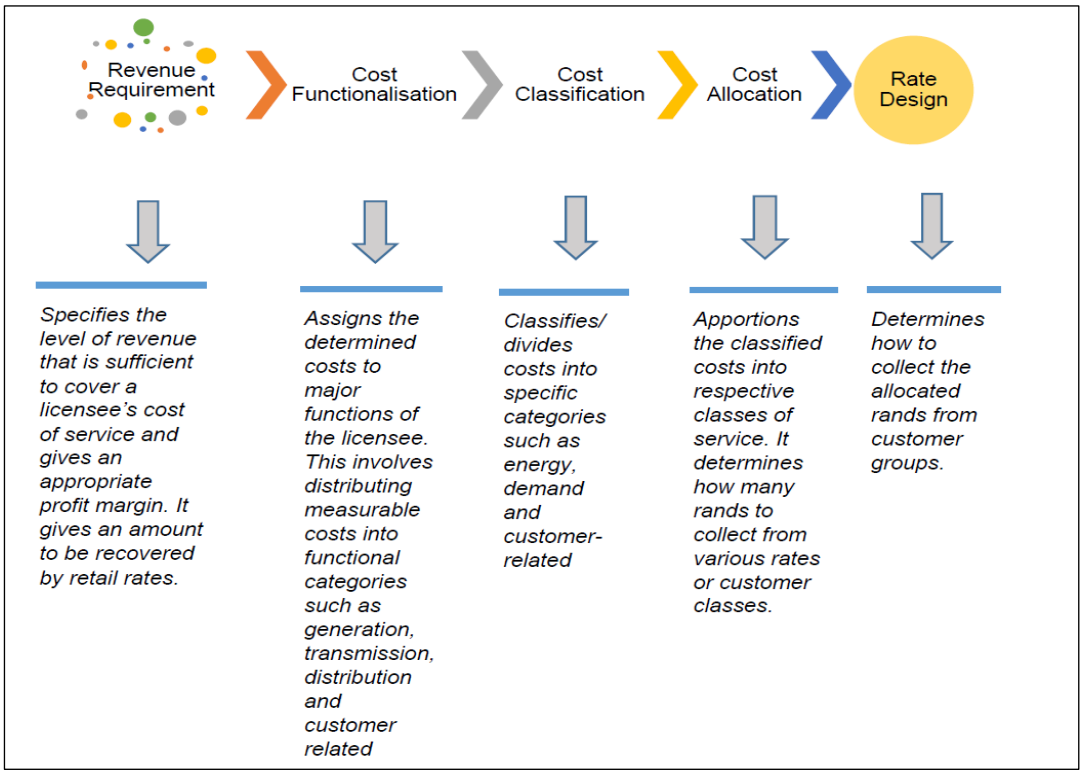


Figure 1: Five steps to determine COS

4.4. The following steps are undertaken to analyse the cost of supply study.

Revenue Requirement

4.5. NERSA assessed the Licensee's revenue requirement and allowable costs for the 2024/25 financial year. The Licensee applied for total allowable costs of R24

844 861 122, while NERSA approved R22 062 422 570, representing a reduction of R2 782 438 552. The reduction mainly relates to adjustments made to the cost of energy losses, depreciation and the return on assets following NERSA's assessment of the prudency and reasonableness of these cost components.

4.6. Energy purchases remain the largest cost driver, accounting for 50.9% of the approved allowable costs.

Table 4: Revenue requirement components

	Total cost (R)						
Revenue Requirement components	Wires	Retail	City Power Total Applied For	% of Total	NERSA Adjustment (R)	NERSA Recommended	% of Total
Allowable costs	R6 901 081 558	R17 943 779 564	R24 844 861 122	100%	(2 782 438 552)	R22 062 422 570	100%
Energy purchases from Eskom - net of cost of energy losses	R1 367 598 857	R10 029 058 285	R11 396 657 142	45,9%	(162 024 802)	R11 234 632 340	50,9%
Energy purchases from Eskom - cost of energy losses	R0	R2 450 957 324	R2 450 957 324	9,9%	(1 133 077 844)	R1 317 879 480	6,0%
Other energy purchases (Kelvin Power Station; City of Ekurhuleni and Mogale City	R0	R2 059 841 990	R2 059 841 990	8,3%	-	R2 059 841 990	9,3%
Depreciation -Replacement Valuation	R1 351 642 789	R36 941 076	R1 388 583 865	5,6%	(689 530 692)	R699 053 173	3,2%
Human Resources Cost	R832 476 580	R1 070 915 448	R1 903 392 027	7,7%	-	R1 903 392 027	8,6%
Repairs & Maitenance (Material)	R1 265 515 878	R0	R1 265 515 878	5,1%	-	R1 265 515 878	5,7%
Cust: Materials & Supplies	R0	R9 451 812	R9 451 812	0,0%	-	R9 451 812	0,0%
Consulting	R47 052 578	R60 529 430	R107 582 008	0,4%	-	R107 582 008	0,5%
Admin_IT_Support: Materials&Supplies	R31 400 467	R73 267 757	R104 668 224	0,4%	-	R104 668 224	0,5%
Administrative Charges	R37 998 476	R88 663 111	R126 661 588	0,5%	-	R126 661 588	0,6%
Bad Debt Provision	R261 098 782	R609 230 491	R870 329 274	3,5%	-	R870 329 274	3,9%
Other Operational expenditure	R448 751 854	R197 377 544	R646 129 398	2,6%	(4 654 815)	R641 474 583	2,9%
Return on Assets	R1 257 545 296	R1 257 545 296	R2 515 090 592	10,1%	(793 150 399)	R1 721 940 193	7,8%
Cost of energy losses disallowed	367 887 991	2 697 845 264	3 065 733 255		(1 054 891 870)	R4 120 625 125	
TOTAL COSTS	7 268 969 549	20 641 624 828	27 910 594 377			26 183 047 695	

4.7. It is important to assess cost efficiency in the 2022/23 financial year, as this is the most recent available actual data. This forms the basis for projecting costs for the 2024/25 financial year, using assumptions to calculate revenue requirements.

4.8. Furthermore, NERSA has verified all expense items included in the revenue requirements to ensure they relate only to the licensee's electricity function. In instances where expenses are deemed inflated or unjustified, these have been adjusted accordingly and expanded on below.

Bulk purchases

4.9. City Power applied for R11 396 657 142 in respect of energy purchases from Eskom, net of the cost of energy losses, representing 45.9% of the total allowable costs. NERSA approved R11 234 632 340 for energy purchases from Eskom (net of energy losses) and R2 059 841 990 for other energy purchases. The Licensee applied for R2 450 957 324 in energy losses; however, the assessment revealed that the Licensee applied an energy loss factor of 15%,

which exceeds the maximum allowable loss level of 12% prescribed in the approved CoS Methodology. NERSA approved R1 317 879 480, reflecting a significant reduction due to the disallowance of excessive energy losses that exceeded prudent and efficient levels. NERSA verified the bulk electricity purchase costs against the audited AFS for the 2022/23 financial year, which served as the base year for the CoS study.

4.10. The total forecast electricity purchases were determined at 9 717 575 898 kWh, comprising 8 469 634 035 kWh purchased from Eskom and 1 247 941 863 kWh purchased from non-Eskom suppliers (Kelvin Power Station, City of Ekurhuleni and Mogale City). The contribution of each supplier to the total forecast purchases was used to determine its weighting in the Average Purchase Price (APP) calculation.

4.11. The APP was calculated as the weighted average of the individual supplier purchase prices, based on each supplier's percentage contribution to the total forecast electricity purchases. As Eskom supplied 87.16% of the forecast electricity purchases and the non-Eskom suppliers supplied 12.84%, the APP reflects the proportionate contribution of each supplier's purchase price.

4.12. The calculated APP was then applied to the total forecast electricity purchases of 9 717 575 898 kWh to determine the total bulk electricity purchase cost. Accordingly, the total bulk electricity purchase cost amounted to R14 112 107 000 for the 2022/23 financial year, R16 626 746 679 for the 2023/24 financial year and R18 732 978 935 for the 2024/25 financial year.

Operational Expenditure

4.13. City Power’s operational expenditure, including depreciation determined in accordance with the Rate of Return (ROR) methodology, amounts to R6 422 314 074 for the 2024/25 financial year. This represents approximately 25% of the total cost of supply and includes depreciation, as reflected in Table 5 below.

Table 5: Total operating expenditure

	Total cost (R)						
Cost Drivers	Wires	Retail	City Power Total Applied For	% of Total	NERSA Adjustment (R)	NERSA Recommended	% of Total
Depreciation -Replacement Valuation	R1 351 642 789	R36 941 076	R1 388 583 865	5,6%	(689 530 692)	R699 053 173	3,2%
Human Resources Cost	R832 476 580	R1 070 915 448	R1 903 392 027	7,7%	-	R1 903 392 027	8,6%
Repairs & Maitenance (Material)	R1 265 515 878	R0	R1 265 515 878	5,1%	-	R1 265 515 878	5,7%
Cust: Materials & Supplies	R0	R9 451 812	R9 451 812	0,0%	-	R9 451 812	0,0%
Consulting	R47 052 578	R60 529 430	R107 582 008	0,4%	-	R107 582 008	0,5%
Admin_IT_Support: Materials&Supplies	R31 400 467	R73 267 757	R104 668 224	0,4%	-	R104 668 224	0,5%
Administrative Charges	R37 998 476	R88 663 111	R126 661 588	0,5%	-	R126 661 588	0,6%
Bad Debt Provision	R261 098 782	R609 230 491	R870 329 274	3,5%	-	R870 329 274	3,9%
Other Operational expenditure	R448 751 854	R197 377 544	R646 129 398	2,6%	(4 654 815)	R641 474 583	2,9%
TOTAL Operating Expenditure	4 275 937 405	2 146 376 669	6 422 314 074	0	(694 185 507)	5 728 128 567	

4.14. The Licensee applied for depreciation based on replacement valuation amounting to R1 388 583 865, representing 5,6% of the total allowable revenue requirement. Human resource costs amount to R1 903 392 027 (7,7%), while repairs and maintenance expenditure totals R1 265 515 878 (5,1%). NERSA notes that adequate provision for maintenance expenditure is critical to ensure network reliability and the long-term sustainability of the distribution network.

4.15. The application further includes a bad debt provision of R870 329 274, representing 3.5% of the total allowable revenue requirement. NERSA assessed the bad debt provision based on the information submitted by the Licensee and considered the amount reasonable for tariff-setting purposes. Accordingly, no adjustment was made to the amount applied for. NERSA will, however, continue to monitor bad debt levels to ensure that only prudent and efficient costs are recovered through approved tariffs and that customers are not required to fund inefficiencies arising from inadequate revenue collection practices.

4.16. NERSA is satisfied that the methodology applied by the Licensee to forecast operating expenditure is reasonable. NERSA notes that the depreciation allowance is based on a RAB derived from a replacement valuation undertaken for insurance purposes as at the 2022/23 financial year and subsequently adjusted using the CPI to derive asset values for the 2024/25 financial year. While this reflects the Licensee's adoption of a return on assets approach, based on replacement valuation, in line with the requirements of the EPP, the underlying asset values should be independently verified for regulatory tariff-setting purposes.

4.17. NERSA assessed the depreciation charge in accordance with the approved CoS Methodology and verified the underlying asset information against the audited AFS for the 2022/23 financial year.

4.18. The CoS Methodology requires depreciation to be calculated on the RAB using the straight-line method over the useful economic life of the assets. In assessing the depreciation claim, NERSA evaluated the asset values, depreciation schedules, asset lives, and supporting financial records submitted by the Licensee. The assessment considered whether the depreciation calculation was consistent with the CoS Methodology and whether the asset values and depreciation information reflected in the CoS study were consistent with the information contained in the audited AFS.

4.19. The assessment revealed that the depreciation amount applied for by the licensee, which was derived using the Replacement Valuation Methodology, was not fully supported by the audited financial information and resulted in a depreciation charge that exceeded the amount determined in accordance with the approved CoS Methodology. NERSA therefore recalculated the depreciation allowance using the asset values and depreciation information verified from the audited AFS and in accordance with the requirements of the CoS Methodology.

4.20. Based on the assessment undertaken, NERSA determined an allowable depreciation expense of R699 053 173, representing a reduction of R689 530 692 from the amount applied for by the Licensee. The adjustment ensures that the approved tariffs support the recovery of prudent and efficient costs while balancing the municipality's financial sustainability with the need to provide affordable electricity tariffs to customers.

4.21. NERSA is satisfied that the recommended depreciation allowance appropriately reflects the prudent and reasonable consumption of assets utilised in the provision of regulated electricity services and is consistent with the principles of cost reflectivity and regulatory prudency embodied in the approved CoS Methodology. Accordingly, NERSA recommends a depreciation allowance of R699 053 173 for tariff determination purposes.

4.22. The recommended depreciation allowance is based on the verified accounting depreciation of R631 689 775 recorded in the audited AFS for the 2022/23 financial year, which served as the base year for the CoS study, as reflected in figures 2 and 3. The amount was indexed using the applicable CPI to determine the depreciation allowance for the 2024/25 financial year, resulting in a recommended amount of R699 053 173.

4.23. Notwithstanding the above, NERSA notes that the Licensee excluded the cost of interest on Eskom amounting to R900 263 514 from the total cost, on the basis that these are within its control.

4.24. NERSA assessed the treatment of FBE costs included in the application and found that the cost of FBE supplied by Eskom, amounting to R4 654 819, is funded through the equitable share allocation. Accordingly, NERSA excluded these costs from the revenue requirement to prevent double recovery through tariffs.

Return on Assets (ROA)

4.25. The CoS Methodology requires the ROA to be determined using the Weighted Average Cost of Capital (WACC), which represents the cost of financing the regulated electricity business through a combination of debt and equity. The WACC, comprising the Cost of Debt (Kd) and the Cost of Equity (Ke), is applied to the RAB to calculate the allowable return on assets and ensure that the licensee is able to recover a reasonable return on capital employed in providing regulated electricity services.

4.26. The Licensee applied for an ROA of R2 515 090 591, representing approximately 10.1% of the total allowable revenue requirement. The ROA constitutes a significant component of the application and has a material impact on the resulting tariff.

4.27. The Licensee's ROA was calculated using a RAB derived from a replacement cost valuation undertaken for insurance purposes.

4.28. In the absence of an appropriate asset valuation methodology, NERSA independently recalculated the ROA in accordance with the approved CoS Methodology, using asset values verified against the audited AFS for the 2022/23 financial year and the Licensee's asset register. Based on this assessment, NERSA determined an allowable ROA of R2 389 129 339. NERSA notes that applying the full calculated ROA would have resulted in an average tariff increase of approximately 16.13% for the 2024/25 financial year.

4.29. Section 15(1) (aA) of the ERA requires the Regulator to allow a licensee a reasonable return proportionate to the risk of the licensed activity. In determining the allowable return, NERSA considered the return derived from the assessment, the risks associated with the licensed activity and the impact of the resulting revenue requirement on the tariff outcome, having regard to the need to avoid unreasonable tariff volatility and price shocks while maintaining the financial viability and sustainability of the licensed activity. Having considered these factors within the applicable regulatory and policy framework, NERSA

approved an ROA of R1 721 940 193, which was considered reasonable and proportionate to the risks of the licensed activity. The approved ROA resulted in an average tariff increase of 12.72% for the 2024/25 financial year. The Licensee is applying for the same average price increase of 12.72% as part of the redetermination of the 2024/25 financial year tariff.

4.30. Section 9.3.3 of the MYPD 4 Methodology provides that 'the Energy Regulator will, however, apply reasonable regulatory judgment in balancing between the need to smooth price increases, allowing the licensee a reasonably cost reflective return on investment, and preventing excessive or inadequate returns'. In determining the allowable return for the 2024/25 financial year, NERSA applied this principle of regulatory judgement, taking into account the need to allow the Licensee a reasonable and cost-reflective return on investment, while also considering the impact of the resulting tariff increase on customers. The Licensee's return was therefore adjusted in accordance with the applicable provisions of the methodology governing the rate-of-return approach. NERSA approved an ROA of R1 721 940 193, which was considered reasonable and proportionate to the risks of the licensed activity. This resulted in an average tariff increase of 12.72% for the 2024/25 financial year.

4.31. The return of R1 721 940 193 was achieved by applying the adjusted WACC of 9.3% instead of the calculated WACC of 12.92%.

4.32. The recommended return represents approximately 7.8% of the total allowable revenue of R22 062 422 570. This indicates that the licensee is not generating an excessive return from electricity tariffs but rather maintaining a relatively modest operating buffer within the electricity business.

4.33. The return forms an important component of the Licensee's electricity business sustainability as it contributes towards:

a) funding future infrastructure refurbishment and replacement;
b) strengthening cash flow and working capital requirements;
c) mitigating financial risks associated with bulk electricity price increases and revenue under-collection; and
d) supporting the long-term financial viability of the electricity undertaking.

4.34. However, the Licensee's ability to realise the recommended return remains dependent on several operational and financial factors, including:

a) the effectiveness of revenue collection;
b) the management of technical and non-technical energy losses;
c) the containment of operating expenditure; and
d) the Licensee's ability to manage Eskom-related debt obligations and avoid additional interest charges and penalties.

4.35. The assessment further indicates that, despite the approved return, the electricity business remains under significant financial pressure due to the high proportion of bulk electricity purchase costs and elevated energy losses. As a result, the approved return should not be interpreted as excessive profitability, but rather as a necessary provision to support the sustainability and resilience of the electricity business.

4.36. Figures 2 and 3 below illustrate the basis on which NERSA determined the allowable depreciation of R631 689 775 (R567 774 000 plus R63 916 000) and the corresponding asset value of R16 709 782 000 (R16 310 723 000 plus R399 059 000), as verified against the audited AFS for the 2022/23 financial year and applied in accordance with the approved CoS Methodology.

Notes to the Annual Financial Statements

Figures in Rand thousand — 2023 — 2022

9. Property, plant and equipment (continued)

Reconciliation of property, plant and equipment - 2023

	Opening balance	Additions	Disposals	Transfers	Depreciation	Impairment reversal	Total
Land	32 095	-	-	-	-	-	32 095
Buildings	777 218	17 159	-	2 297	(14 662)	-	782 012
Plant and machinery	14 913 713	1 018 617	(289)	(2 297)	(536 141)	22 133	15 415 736
Furniture and fixtures	5 508	1 459	(6)	-	(789)	-	6 172
Motor vehicles	17 150	4 763	-	-	(7 774)	-	14 139
IT equipment	17 342	51 635	-	-	(8 408)	-	60 569
	15 763 026	**1 093 633**	**(295)**	**-**	**(567 774)**	**22 133**	**16 310 723**

Figure 2: Asset values and depreciation historical values

Notes to the Annual Financial Statements

Figures in Rand thousand — 2023 — 2022

10. Intangible assets

	2023			2022		
	Cost	Accumulated amortisation and accumulated impairment	Carrying value	Cost	Accumulated amortisation and accumulated impairment	Carrying value
Capacity rights	261 228	-	261 228	261 228	-	261 228
Computer software	429 192	(291 361)	137 831	408 652	(260 101)	148 551
Total	**690 420**	**(291 361)**	**399 059**	**669 880**	**(260 101)**	**409 779**

Reconciliation of intangible assets - 2023

	Opening balance	Additions	Disposals	Amortisation	Total
Capacity rights	261 228	-	-	-	261 228
Computer software	148 551	58 231	(5 035)	(63 916)	137 831
	409 779	**58 231**	**(5 035)**	**(63 916)**	**399 059**

Figure 3: Other asset values and depreciation historical values

4.37. Figures 4, 5 and 6 below illustrate the basis used by the Licensee to determine the allowable depreciation of R1 388 583 864 (R1 351 642 789 plus R36 941 076) and the corresponding asset value of R39 922 072 876 (R38 863 971 222 plus R1 058 101 654). NERSA notes that the depreciation allowance was determined using a RAB derived from a replacement valuation undertaken for insurance purposes as at the 2022/23 financial year. The valuation was subsequently escalated using the CPI to determine the asset values applicable to the 2024/25 financial year.

Summary of network asset register analysis – closing balance at the end of Year 0

Asset Group Label	Asset Value (Rand)	Annual depreciation - calculated	Accumulated depreciation to date	Net depreciated value
132-275kV / Mixed	R 2 348 491 203	R 61 069 670	R 531 476 907	R 1 755 944 626
22-33kV / Mixed	R 4 696 982 406	R 122 139 340	R 1 062 953 814	R 3 511 889 252
6.6-11 kV / Mixed	R 32 878 876 840	R 854 975 378	R 7 440 676 696	R 24 583 224 766
400 V / Mixed	R 7 045 473 608	R 183 209 010	R 1 594 430 720	R 5 267 833 878
	R 46 969 824 056	**R 1 221 393 397**	**R 10 629 538 137**	**R 35 118 892 523**

Figure 4: Network asset values and depreciation replacement values

Summary of other assets register analysis – closing balance at the end of Year 0

Asset Group Name	Asset Value (Rand)	Annual depreciation	Accumulated depreciation to date	Net depreciated value
Land	R 32 095 000	R -	R -	
Buildings	R 1 163 398 337	R 16 410 295	R 271 729 050	R 875 258 992
Furniture & Vehicles	R 25 999 000	R 789 000	R 19 038 000	R 6 172 000
Motor Vehicles	R 43 340 000	R 7 774 000	R 21 427 000	R 14 139 000
IT Equpment	R 154 602 000	R 8 408 000	R 85 625 000	R 60 569 000
	R 1 419 434 337	**R 33 381 295**	**R 397 819 050**	**R 956 138 992**

Figure 5: Other asset values and depreciation replacement values

City Power's ROR calculation based on the WACC

	Year 1	Year 2		
Bechmark Cost Reflective WACC	11,4%	11,4%		
Proposed WACC (real)	6,30%	6,30%		
CPI	6,00%	4,40%		
DRC (Replacement)	R 37 226 026 075	38 863 971 222	Wires	Retail
Other Assets	R 1 013 507 331	1 058 101 654		
RAB Valuation		39 922 072 876		
Depreciation RAB	R 1 294 677 001	1 351 642 789	1 351 642 789	
Depreciation Other asets	R 35 384 172,33	R 36 941 076		R 36 941 076
Rate of Return		2 515 090 591	1 257 545 296	1 257 545 296

Figure 6: ROR calculations

Determination of the Real Pre-Tax Weighted Average Cost of Capital (WACC)

4.38. The CoS Methodology requires the ROA to be determined using the WACC, which reflects the cost of financing the regulated business through a combination of debt and equity. The WACC comprises the Cost of Debt (Kd) and the Cost of Equity (Ke) and is applied to the RAB to calculate the allowable return on assets. The calculation is undertaken in accordance with the approved CoS Methodology.

Step 1: Determine the Regulatory Asset Base (RAB)

Audited 2022/23 asset values:

Property, Plant and Equipment = 16 310 723 000
Intangible Assets = R399 059 000
Total Base-Year RAB of R16 709 782 000 (R16 310 723 000 + R399 059 000)

Step 2: Escalate the Asset Base to 2024/25

Escalate PPE

2023/24 Inflation (6.0%) (R16 310 723 000 x 1,06) = R17 289 366 380

2024/25 Inflation (4.4%) (R17 289 366 380 X1,044) =R18 050 098 501

Escalate Intangible Assets

2023/24 Inflation (6.0%) (R399 059 000 x 1,06) = R423 002 540

2024/25 Inflation (4.4%) (R423 002 540 X1,044) = R441 614 652

Inflation-Adjusted RAB

For 2024/25 FY (R18 050 098 501 + R441 614 652) =R18 491 713 153

Step 3: Determine Cost of Debt (Kd)

City Power submitted WACC model, the following assumptions were applied:

Risk-free rate 10,059%
Debt premium 3,500%

Therefore: Kd = (10,059% + 3,500%) = 13,559%

Step 4: Determine Cost of Equity (Ke)

NERSA Methodology:
$Ke=Rf+(\beta \times MRP)$

Risk-free rate:
$Rf=10.059\%$

Levered beta:
$\beta=0.82$

Market risk premium:
$MRP=6.00\%$

Therefore:
$Ke=10,059\%+(0,82\times 6,00\%)$
$=10,059\%+4,920\%$
$=14,979\%$

<u>Convert to Pre-Tax Cost of Equity</u>

Tax rate: 27%
Ke Pretax = (14,98%)/ (1-0,27)
(14,98%)/ (0,73) = 20,52%

Step 5: Determine Capital Structure

City Power WACC Model:
Debt weight: 27,71%
Equity weight: 72,29%

Step 6: Calculate Nominal Pre-Tax WACC

<u>NERSA Methodology:</u>

$WACC = (Kd \times G) + [Ke\times(1-G)]$

Substituting values:
Debt Contribution
$13,559\%\times 28\%$
$=3,796\%$

Equity Contribution

20,52%×72%
=14,774%

Nominal WACC

=3,796%+14,774%
=18,57%
(Nominal WACC=18,57%)

Step 7: Convert to Real Pre-Tax WACC

NERSA Methodology:

Real WACC= ((1+Nominal WACC)/(1+Inflation))-1

Using City Power inflation:
= (1,1857) / (1,05)-1
= 1,1294-1
= 0,1292
= 12,92%
(Real WACC=12,92%)

Step 8: Calculate Return on Assets (ROA)

NERSA Methodology:

ROA = RAB x Real WACC

Substituting values = R18 491 713 153 X 12,92%
ROA = R2 389 129 339

4.39. The Licensee applied for an ROA of R2 515 090 591. NERSA independently assessed the asset values and recalculated the allowable ROA at R2 389 129 339 in accordance with the approved CoS Methodology. The final allowable return remained a regulatory determination by NERSA, having regard to the Licensee's entitlement to a reasonable return proportionate to the risk of the licensed activity and the impact of the resulting tariff on customers.

Return on Assets and Asset Valuation

4.40. The comparative assessment below illustrates the effect of the different asset valuation bases on the RAB, ROA and tariff impact.

Comparative Assessment of Asset Valuation Scenarios

Scenario	Basis of Valuation	Asset Value/RAB	Return on Assets (ROA)	Tariff Impact
Scenario 1 Insurance Valuation	Replacement valuation undertaken for insurance purposes	R39 922 072 876	R4 551 116 308	37.34%
Scenario 2 Insurance Valuation	Replacement Valuation Approach, Adjusted to Reflect Customer Affordability	R39 922 072 876	R2 515 090 591	26.94%
Scenario 3 AFS Verified historical value	Historical asset values supported by audited AFS and verification	R18 491 713 153	R2 389 129 339	16.13%
Scenario 4 NERSA-approved position	Historical value approach with adjustment for customer affordability	R18 491 713 153	R1 721 940 193	12.72%

Figure 7: Asset valuation scenarios

4.41. NERSA considered the asset values arising from both the replacement valuation and the historical cost approach. The assessment showed that the replacement valuation would result in a significantly higher asset base and, consequently, a higher return on assets, depreciation and tariff impact. NERSA therefore considered the implications of each approach, including the reliability and verifiability of the asset values for regulatory purposes and the affordability and sustainability of the resulting tariffs.

4.42. Having considered the applicable Cost of Supply Framework and the potential impact of the different valuation approaches on customers, NERSA adopted the historical value approach as the basis for determining the RAB. NERSA further exercised its regulatory discretion in determining the allowable return on assets, taking into account customer affordability and the need to allow the Licensee a reasonable return proportionate to the risks of the licensed activity.

4.43. The verification provided a more reliable and auditable basis for determining the RAB, depreciation and ROA. Under the CoS Methodology, the WACC is applied to the RAB to determine the allowable return on capital employed in the regulated electricity business.

4.44. Section 7.2 of the CoS Framework, read with section 15(1) (aA) of the ERA, requires that a licensee be allowed a reasonable return proportionate to the risk of the licensed activity.

4.45. Section 17.1 of the CoS Framework recognises asset valuation as a key component of the cost allocation methodology, while EPP policy position 1(a) requires the revenue requirement to provide for the full cost of supply, including a reasonable risk-adjusted return on appropriate asset values.

4.46. Having considered the available evidence, NERSA found that the AFS-verified asset values provided a more reliable basis for the regulatory assessment than reliance solely on the insurance valuation.

4.47. Although the calculated ROA of R2 389 129 339 was supported by the verified RAB and WACC, NERSA considered the resulting tariff impact and customer affordability in determining the final allowable return.

4.48. Accordingly, NERSA approved an ROA of R1 721 940 193. The approved return is considered reasonable and proportionate to the risks of the licensed activity and balances the Licensee's need for financial sustainability with the interests of customers.

4.49. The approved ROA resulted in an average tariff increase of 12.72% for the 2024/25 financial year.

4.50. The approved revenue requirement under the Rate of Return approach is calculated as follows:

4.51. Approved revenue requirement = Approved operating expenditure + Approved ROA

= R5 728 128 567 + R1 721 940 193

= R7 450 068 760

Cost Functionalisation

4.52. The Licensee categorised its applied-for revenue requirement of R24 844 861 120 into the 'Wires' and 'Retail' business functions in accordance with the approved NERSA CoS Framework. Following its assessment, NERSA approved a revenue requirement of R22 062 422 570. NERSA verified the underlying costs and found them to be aligned with the approved revenue requirement, as shown in Table 6 below.

Table 6: Cost breakdown by function

	Total Functionalised Costs (R)			
Functions	Wires	Retail	Total	NERSA Recommended
Eskom Energy Purchase - excl. losses	1 367 598 857	10 029 058 285	11 396 657 142	11 234 632 340
Eskom Energy Purchase - cost of losses	-	2 450 957 324	2 450 957 324	1 317 879 480
Other Energy Purchase	-	2 059 841 990	2 059 841 990	2 059 841 990
CAPEX and return	1 257 545 296	1 257 545 296	2 515 090 591	1 721 940 193
Depreciation	1 351 642 789	36 941 076	1 388 583 864	699 053 173
Network repairs & maintenance	1 265 515 878	-	1 265 515 878	1 265 515 878
HVMVLV: Materials&Supplies(R&M)	-	9 451 812	9 451 812	9 451 812
Consult(R&M)	47 052 578	60 529 430	107 582 008	107 582 008
Salary(R&M)	832 476 580	1 070 915 448	1 903 392 027	1 903 392 027
Other Operating Expenses	448 751 854	197 377 544	646 129 398	641 474 583
Bad Debt Provisions	261 098 782	609 230 491	870 329 274	870 329 274
Admin_IT_Support: Materials&Supplies	31 400 467	73 267 757	104 668 224	104 668 224
Admin Charges COJ	37 998 476	88 663 111	126 661 588	126 661 588
	6 901 081 557	17 943 779 563	24 844 861 120	22 062 422 570

4.53. The wires function is mainly driven by network repairs and maintenance, while energy purchases are the primary cost driver of the retail function.

Cost Classification

4.54. The Licensee classified its costs into energy-, demand- and customer-related categories in accordance with the NERSA CoS Framework. Following assessment, NERSA approved a revenue requirement of R22 062 422 570, as shown in Table 7 below.

Table 7: Cost classification

Revenue Requirement components	Demand/Capacity	Energy	Basic/ Customer	Total	NERSA Recommended
Energy purchases from Eskom - net of cost of losse	R1 367 598 857	R9 527 605 371	R501 452 914	R11 396 657 142	R11 234 632 340
Energy purchases from Eskom - cost of losses	R0	R2 450 957 324	R0	R2 450 957 324	R1 317 879 480
Other energy purchases	R0	R1 956 849 890	R102 992 099	R2 059 841 990	R2 059 841 990
Bulk Purchases -Generation	R1 367 598 857	R13 935 412 585	R604 445 014	R15 907 456 456	R14 612 353 810
Depreciation -Replacment Valuation	R1 351 642 789	R36 941 076	R0	R1 388 583 864	R699 053 173
Human Resources Cost	R832 476 580	R1 070 915 448	R0	R1 903 392 027	R1 903 392 027
Repairs & Maitenance (Material)	R1 265 515 878	R0	R0	R1 265 515 878	R1 265 515 878
Cust: Materials & Supplies	R0	R9 451 812	R0	R9 451 812	R9 451 812
Consulting	R47 052 578	R0	R60 529 430	R107 582 008	R107 582 008
Admin_IT_Support: Materials&Supplies	R31 400 467	R0	R73 267 757	R104 668 224	R104 668 224
Administrative Charges	R37 998 476	R0	R88 663 111	R126 661 588	R126 661 588
Bad Debt Provision	R261 098 782	R426 461 344	R182 769 147	R870 329 274	R870 329 274
Other Operational expenditure	R448 751 854	R138 164 281	R59 213 263	R646 129 398	R641 474 583
Other revenues	R0	R0	R0	R0	
Return on Assets	R1 257 545 296	R1 257 545 296	R0	R2 515 090 591	R1 721 940 193
Total City Power Operating Cost	R5 533 482 700	R2 939 479 256	R464 442 709	R8 937 404 665	R7 450 068 760
Total Cost	**R6 901 081 557**	**R16 874 891 841**	**R1 068 887 723**	**R24 844 861 120**	**R22 062 422 570**

4.55. Energy purchases constitute energy-driven costs, with the highest expenses occurring during summer under standard time-of-use, mainly because summer spans a larger portion of the year. Demand-driven costs are also predominantly incurred in summer. Customer-driven costs are primarily attributed to 'Other OPEX', which encompasses expenses related to providing electricity distribution services to customers.

Cost Allocation

4.56. In this step, the Licensee's revenue requirements of R24 844 861 120, as shown in Table 8, were allocated among the various customer categories. Following its assessment, NERSA approved a revenue requirement of R22 062 422 570, as shown in Table 8 below.

Table 8: Allocation of costs between customer categories (based on replacement value figures)

Revenue Requirement components	Total Demand	Total Energy	Total Customer	Total Rev. Req.	Projected Sales Vol (kWh)	Projected ASP (kWh)	Total Rev. Year 01 (Rand)	ASP Y1	Increase
Residential Prepaid	**R785 869 080**	**R2 015 524 244**	**R537 807 552**	R3 339 200 876	758 359 784	R4,40	R1 648 294 991	R2,17	103%
Residential Single Phase 60A	**R521 897 924**	**R2 766 900 055**	**R267 869 661**	R3 556 667 640	1 041 071 937	R3,42	R2 809 408 569	R2,70	27%
Residential Single Phase 80A	**R260 948 962**	**R1 431 155 201**	**R133 934 830**	R1 826 038 993	538 485 484	R3,39	R1 463 270 733	R2,72	25%
Residential Three Phase 80A	**R75 327 267**	**R238 525 867**	**R22 322 472**	R336 175 606	89 747 581	R3,75	R253 776 547	R2,83	32%
Residential Reseller	**R1 079 275 216**	**R740 260 741**	**R4 569 032**	R1 824 104 989	278 530 004	R6,55	R448 383 585	R1,61	307%
Residential Single Phase Seasonal (80A)	**R37 663 634**	**R166 968 107**	**R11 161 236**	R215 792 976	62 823 307	R3,43	R160 171 103	R2,55	35%
Residential Three Phase Seasonal (80A)	**R37 663 634**	**R166 968 107**	**R11 161 236**	R215 792 976	62 823 307	R3,43	R165 120 743	R2,63	31%
Business Prepaid (Seasonal)	**R159 550 204**	**R201 137 153**	**R15 067 894**	R375 755 251	75 679 729	R4,97	R261 897 042	R3,46	43%
Business Conventioanal (Seasonal)	**R496 923 771**	**R1 520 751 513**	**R46 929 460**	R2 064 604 744	572 196 932	R3,61	R1 808 862 017	R3,16	14%
Business Reseller (Seasonal)	**R240 899 484**	**R133 074 511**	**R743 482**	R374 717 477	50 070 525	R7,48	R154 419 700	R3,08	143%
Agriculture	**R1 167 997**	**R2 392 706**	**R108 143**	R3 668 846	900 278	R4,08	R2 659 737	R2,95	38%
Streetlight/Robots	**R0**	**R0**	**R0**	R0	-	R0,00	R0	R0,00	0%
LPU Demand LV	**R1 598 124 025**	**R2 880 067 425**	**R14 373 978**	R4 492 565 428	1 288 814 513	R3,49	R4 420 936 112	R3,43	2%
LPU Demand MV	**R503 364 934**	**R1 133 166 339**	**R950 755**	R1 637 482 028	522 252 490	R3,14	R1 586 424 679	R3,04	3%
LPU TOU LV	**R299 394 783**	**R643 992 908**	**R1 130 993**	R944 518 684	288 183 325	R3,28	R840 970 273	R2,92	12%
LPU TOU MV	**R796 795 678**	**R2 735 582 096**	**R752 493**	R3 533 130 267	1 260 772 149	R2,80	R3 475 247 362	R2,76	2%
AEL	**R6 214 963**	**R98 424 868**	**R4 506**	R104 644 337	64 208 443	R1,63	R72 923 456	R1,14	43%
Total Cost	**6 901 081 557**	**R16 874 891 841**	**R1 068 887 723**	**R24 844 861 120**	6 954 919 786	R3,57	**R19 572 766 649**	R2,81	27%

Table 9: Allocation of costs between customer categories (according to NERSA)

Revenue Requirement components	Total Demand	Total Energy	Total Customer	Total Rev. Req.	Projected Sales Vol (kWh)	Projected ASP (kWh)	Total Rev. Year 01 (Rand)	ASP Y1	Increase
Residential Prepaid	**R661 694 137**	**R1 795 788 988**	**R534 005 939**	R2 991 489 065	758 359 784	R3,94	R1 648 294 991	R2,17	81%
Residential Single Phase 60A	**R439 432 987**	**R2 465 248 763**	**R265 976 164**	R3 170 657 914	1 041 071 937	R3,05	R2 809 408 569	R2,70	13%
Residential Single Phase 80A	**R219 716 493**	**R1 275 128 671**	**R132 988 082**	R1 627 833 246	538 485 484	R3,02	R1 463 270 733	R2,72	11%
Residential Three Phase 80A	**R63 424 828**	**R212 521 445**	**R22 164 680**	R298 110 953	89 747 581	R3,32	R253 776 547	R2,83	17%
Residential Reseller	**R908 739 256**	**R659 556 486**	**R4 536 735**	R1 572 832 477	278 530 004	R5,65	R448 383 585	R1,61	251%
Residential Single Phase Seasonal (80A)	**R31 712 414**	**R148 765 012**	**R11 082 340**	R191 559 766	62 823 307	R3,05	R160 171 103	R2,55	20%
Residential Three Phase Seasonal (80A)	**R31 712 414**	**R148 765 012**	**R11 082 340**	R191 559 766	62 823 307	R3,05	R165 120 743	R2,63	16%
Business Prepaid (Seasonal)	**R134 339 723**	**R179 208 901**	**R14 961 383**	R328 510 007	75 679 729	R4,34	R261 897 042	R3,46	25%
Business Conventioanal (Seasonal)	**R418 404 992**	**R1 354 957 069**	**R46 597 728**	R1 819 959 789	572 196 932	R3,18	R1 808 862 017	R3,16	1%
Business Reseller (Seasonal)	**R202 835 027**	**R118 566 543**	**R738 226**	R322 139 796	50 070 525	R6,43	R154 419 700	R3,08	109%
Agriculture	**R983 443**	**R2 131 850**	**R107 378**	R3 222 671	900 278	R3,58	R2 659 737	R2,95	21%
Streetlight/Robots	**R0**	**R0**	**R0**	R0	-	R0,00	R0	R0,00	0%
LPU Demand LV	**R1 345 604 917**	**R2 618 684 562**	**R14 272 372**	R3 978 561 851	1 288 814 513	R3,09	R4 420 936 112	R3,43	-10%
LPU Demand MV	**R423 828 389**	**R1 034 213 835**	**R944 035**	R1 458 986 258	522 252 490	R2,79	R1 586 424 679	R3,04	-8%
LPU TOU LV	**R252 087 501**	**R585 546 807**	**R1 122 999**	R838 757 307	288 183 325	R2,91	R840 970 273	R2,92	0%
LPU TOU MV	**R670 894 227**	**R2 496 700 397**	**R747 174**	R3 168 341 798	1 260 772 149	R2,51	R3 475 247 362	R2,76	-9%
AEL	**R5 232 939**	**R94 662 494**	**R4 474**	R99 899 907	64 208 443	R1,56	R72 923 456	R1,14	37%
Total Cost	**5 810 643 686**	**R15 190 446 834**	**R1 061 332 050**	**R22 062 422 570**	6 954 919 786	R3,17	**R19 572 766 649**	R2,81	13%

Rate Design

4.57. The CoS study results indicate a required tariff increase of 27%, as illustrated in Table 10 below. However, the Licensee proposed an average tariff increase of 12.72% for the 2024/25 financial year. In arriving at this proposal, the Licensee considered the need to maintain a sustainable tariff level that supports electricity demand, enables the recovery of Eskom bulk electricity costs, maintains customer affordability and supports the long-term financial sustainability of the electricity business.

Table 10: Rate design

Results BEFORE phasing			
	BAU	**New rates (Dashboard selection) City Power**	**New rates (Dashboard selection) NERSA Recommendation**
Total revenue forecast (with new rates)	19 572 766 649	**24 844 861 120**	**22 062 422 570**
	Additional Revenue Required	5 272 094 472	2 489 655 921
Average increase in rates	**27%**		**12,72%**

4.58. The licensee is not proposing any structural changes to its tariffs for the 2024/25 financial year.

5. CONCLUSION ON THE COS

5.1. NERSA recognises that significantly high tariff increases may result in reduced consumption, lower revenue collection and constraints in meeting financial obligations, including payments to Eskom.

5.2. In its evaluation for the assessment of the tariff applications, NERSA considered the following principles.

5.3. The CoS study indicated an allowable revenue requirement of R24 844 861 120 based on the Licensee's submitted valuation approach, compared to the Licensee's proposed average tariff increase of 12.72%. NERSA considered that the CoS outcome should inform, but not determine, the final tariff decision, which must also take account of the applicable legal and regulatory requirements, customer impact and affordability.

5.4. For the tariff redetermination, NERSA did not rely solely on the replacement valuation used by the Licensee. The valuation was undertaken for insurance purposes and the underlying asset values, and depreciation were not fully supported by the audited financial information. NERSA therefore verified the

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							retained as the recommended tariffs.

2. Residential Prepaid High	2023/24 Approved	% Increase	2024/2025 Approved	2024/2025 Redetermination Tariff	2024/2025 Recommended Tariff	2024/2025 Recommended % Increase	Analysis and Key Findings
Block 1 (0–350 kWh)	209,67	12,72%	236,34	236,34	236,34	12,72%	The Residential Prepaid High tariff was approved at an increase of 12.72% across all energy consumption blocks for the 2024/25 financial year. In addition, a new Service Charge of R70.00 per month and a new Capacity Charge of R130.00 per month were introduced as part of the tariff restructuring process. The approved tariffs, including the new fixed charges, are retained as the recommended tariffs to
Block 2 (350–500 kWh)	240,51	12,72%	271,10	271,10	271,10	12,72%	
Block 3 (>500 kWh)	274,05	12,72%	308,91	308,91	308,91	12,72%	
Service Charge (R/month)	0,00	New	70,00	70,00	70,00	0	
Capacity Charge (R/month)	0,00	New	130,00	130,00	130,00	0	

							enhance cost reflectivity and support the financial sustainability of the electricity undertaking.

3. Residential Single Phase 60A	2023/24 Approved	% Increase	2024/2025 Approved	2024/2025 Redetermination Tariff	2024/2025 Recommended Tariff	2024/2025 Recommended % Increase	Analysis and Key Findings
Block 1 (0–500 kWh)	201,63	12,72%	227,28	227,28	227,28	12,72%	The Residential Single Phase 60A tariff was approved at a uniform increase of 12.72% across all energy consumption blocks, as well as the service and capacity charges, for the 2024/25 financial year. The approved tariffs are retained as the recommended tariffs, ensuring tariff stability, cost reflectivity, and continued support for the financial sustainability of the electricity undertaking.
Block 2 (501–1000 kWh)	231,40	12,72%	260,83	260,83	260,83	12,72%	
Block 3 (1001–2000 kWh)	248,47	12,72%	280,08	280,08	280,08	12,72%	
Block 4 (2001–3000 kWh)	262,15	12,72%	295,50	295,50	295,50	12,72%	
Block 5 (>3000 kWh)	275,02	12,72%	310,00	310,00	310,00	12,72%	
Service Charge (R/month)	209,18	12,72%	235,79	235,79	235,79	12,72%	
Capacity Charge (R/month)	616,20	12,72%	694,58	694,58	694,58	12,72%	

4. Residential Single Phase 80A	2023/24 Approved	% Increase	2024/2025 Approved	2024/2025 Redetermination Tariff	2024/2025 Recommended Tariff	2024/2025 Recommended % Increase	Analysis and Key Findings
Block 1 (0–500 kWh)	201,63	12,72%	227,28	227,28	227,28	12,72%	The Residential Single Phase 80A tariff was approved at a uniform increase of 12.72% across all energy consumption blocks, the service charge, and the capacity charge for the 2024/25 financial year. The approved tariffs are retained as the recommended tariffs, as they remain reasonable, cost-reflective and supportive of the financial sustainability of the electricity undertaking.
Block 2 (501–1000 kWh)	231,40	12,72%	260,83	260,83	260,83	12,72%	
Block 3 (1001–2000 kWh)	248,47	12,72%	280,08	280,08	280,08	12,72%	
Block 4 (2001–3000 kWh)	262,15	12,72%	295,50	295,50	295,50	12,72%	
Block 5 (>3000 kWh)	275,02	12,72%	310,00	310,00	310,00	12,72%	
Service Charge (R/month)	209,18	12,72%	235,79	235,79	235,79	12,72%	
Capacity Charge (R/month)	677,58	12,72%	763,77	763,77	763,77	12,72%	
5. Residential Three Phase (<= 80A)	**2023/24 Approved**	**% Increase**	**2024/2025 Approved**	**2024/2025 Redetermination Tariff**	**2024/2025 Recommended Tariff**	**2024/2025 Recommended % Increase**	**Analysis and Key Findings**
Block 1 (0–500 kWh)	201,63	12,72%	227,28	227,28	227,28	12,72%	

Block 2 (501–1000 kWh)	231,40	12,72%	260,83	260,83	260,83	12,72%	The Residential Three Phase (≤ 80A) tariff was approved at an increase of 12.72% across all energy consumption blocks and the service charge, while the capacity charge increased by 12.19% for the 2024/25 financial year. The approved tariffs are retained as the recommended tariffs, as they remain reasonable, cost-reflective and supportive of the financial sustainability of the electricity undertaking.
Block 3 (1001–2000 kWh)	248,47	12,72%	280,08	280,08	280,08	12,72%	
Block 4 (2001–3000 kWh)	262,15	12,72%	295,50	295,50	295,50	12,72%	
Block 5 (>3000 kWh)	275,02	12,72%	310,00	310,00	310,00	12,72%	
Service Charge (R/month)	209,18	12,72%	235,79	235,79	235,79	12,72%	
Capacity Charge (R/month)	848,04	12,19%	951,45	951,45	951,45	12,19%	

6. Residential Reseller Conventional (<=80A)	**2023/24 Approved**	**% Increase**	**2024/2025 Approved**	**2024/2025 Redetermination Tariff**	**2024/2025 Recommended Tariff**	**2024/2025 Recommended % Increase**	**Analysis and Key Findings**

Block 1 (0–350 kWh)			212,71	212,71	212,71	0	The Residential Reseller Conventional (≤80A) tariff was introduced for the 2024/25 financial year, with new energy charges applicable across the three consumption blocks. The service charge and capacity charge increased by 12.72%, while the energy charges remain unchanged during the redetermination process.
Block 2 (350–500 kWh)			243,99	243,99	243,99	0	
Block 3 (>500 kWh)			278,02	278,02	278,02	0	
Service Charge (R/month)	210,17	12,72%	236,90	236,90	236,90	12,72%	
Capacity Charge (R/month)	848,04	12,72%	955,91	955,91	955,91	12,72%	

7. Residential Seasonal (<=80A)	2023/24 Approved	% Increase	2024/2025 Approved	2024/2025 Redetermination Tariff	2024/2025 Recommended Tariff	2024/2025 Recommended % Increase	Analysis and Key Findings
Summer Energy Charges							
Block 1 (0–500 kWh)	191,77	12,72%	216,16	216,16	216,16	12,72%	The Residential Seasonal (≤80A) tariff was approved at a uniform increase of 12.72% across all summer and winter energy charges, as well as the service and capacity charges, for the 2024/25 financial year. The approved tariffs are retained as the recommended tariffs, as they remain reasonable, cost-reflective and supportive of the financial sustainability of the electricity undertaking.
Block 2 (501–1000 kWh)	221,54	12,72%	249,72	249,72	249,72	12,72%	
Block 3 (1001–2000 kWh)	238,62	12,72%	268,97	268,97	268,97	12,72%	
Block 4 (2001–3000 kWh)	252,29	12,72%	284,38	284,38	284,38	12,72%	
Block 5 (>3000 kWh)	265,16	12,72%	298,89	298,89	298,89	12,72%	
Winter Energy Charges							
Block 1 (0–500 kWh)	228,79	12,72%	257,89	257,89	257,89	12,72%	
Block 2 (501–1000 kWh)	258,56	12,72%	291,45	291,45	291,45	12,72%	
Block 3 (1001–2000 kWh)	275,63	12,72%	310,69	310,69	310,69	12,72%	
Block 4 (2001–3000 kWh)	283,72	12,72%	319,81	319,81	319,81	12,72%	
Block 5 (>3000 kWh)	302,18	12,72%	340,62	340,62	340,62	12,72%	
		12,72%					
Service Charge (R/month)	209,18	12,72%	235,79	235,79	235,79	12,72%	
Capacity Charge (R/month)	844,08	12,72%	951,45	951,45	951,45	12,72%	

8. Residential Time-of-Use (<=80A)	2023/24 Approved	% Increase	2024/2025 Approved	2024/2025 Redetermination Tariff	2024/2025 Recommended Tariff	2024/2025 Recommended % Increase	Analysis and Key Findings
Summer Energy Charges							
Peak	244,48	12,72%	275,58	275,58	275,58	12,72%	The Residential Time-of-Use (≤80A) tariff was approved at a uniform increase of 12.72% across all summer and winter energy charges, as well as the service and capacity charges, for the 2024/25 financial year. The approved tariffs are retained as the recommended tariffs, ensuring continued cost reflectivity, preservation of Time-of-Use pricing signals, and support for the financial sustainability of the electricity undertaking.
Standard	193,40	12,72%	218,00	218,00	218,00	12,72%	
Off-peak	152,15	12,72%	171,50	171,50	171,50	12,72%	
Winter Energy Charges							
Peak	562,47	12,72%	634,02	634,02	634,02	12,72%	
Standard	230,41	12,72%	259,72	259,72	259,72	12,72%	
Off-peak	162,59	12,72%	183,27	183,27	183,27	12,72%	
Service Charge (R/month)	209,18	12,72%	235,79	235,79	235,79	12,72%	
Capacity Charge (R/month)	844,08	12,72%	951,45	951,45	951,45	12,72%	

9. Business Prepaid	2023/24 Approved	% Increase	2024/2025 Approved	2024/2025 Redetermination Tariff	2024/2025 Recommended Tariff	2024/2025 Recommended % Increase	Analysis and Key Findings
Summer Charges							
Block 1 (0–500 kWh)	315,73	-2,44%	308,04	308,04	308,04	-2,44%	The Business Prepaid tariff was restructured to introduce seasonal energy charges, resulting in lower summer energy charges and higher winter energy charges. In addition, new service and capacity charges were introduced for different demand categories. The approved tariffs are retained as the recommended tariffs.
Block 2 (501–1000 kWh)	345,35	-2,10%	338,11	338,11	338,11	-2,10%	
Block 3 (1001–2000 kWh)	361,75	-1,99%	354,56	354,56	354,56	-1,99%	
Block 4 (2001–3000 kWh)	374,66	-1,91%	367,49	367,49	367,49	-1,91%	
Block 5 (>3000 kWh)	386,64	-1,87%	379,41	379,41	379,41	-1,87%	
Winter Energy Charges							
Block 1 (0–500 kWh)	315,73	2,14%	322,48	322,48	322,48	2,14%	
Block 2 (501–1000 kWh)	345,35	1,66%	351,09	351,09	351,09	1,66%	
Block 3 (1001–2000 kWh)	361,75	1,38%	366,76	366,76	366,76	1,38%	
Block 4 (2001–3000 kWh)	374,66	1,27%	379,43	379,43	379,43	1,27%	
Block 5 (>3000 kWh)	386,64	0,98%	390,42	390,42	390,42	0,98%	
Basic Charges (<=50kVA)							

Service Charge (R/month)			690,38	690,38	690,38	0	
Capacity Charge (R/month)			661,90	661,90	661,90	0	
Basic Charges (>50kVA<=100kVA)							
Service Charge (R/month)	-		690,38	690,38	690,38	0	
Capacity Charge (R/month)	-		945,88	945,88	945,88	0	

10. Business Conventional	2023/24 Approved	% Increase	2024/2025 Approved	2024/2025 Redetermination Tariff	2024/2025 Recommended Tariff	2024/2025 Recommended % increase	Analysis and Key Findings
Summer Energy Charges							
Block 1 (0–500 kWh)	273,28	12,72%	308,04	308,04	308,04	12,72%	The Business Conventional tariff was approved at a uniform increase of 12.72% across all summer and winter energy charges, as well as the service and capacity charges for all demand categories. The approved tariffs are retained as the recommended tariffs, as they remain reasonable,
Block 2 (501–1000 kWh)	299,96	12,72%	338,11	338,11	338,11	12,72%	
Block 3 (1001–2000 kWh)	314,55	12,72%	354,56	354,56	354,56	12,72%	
Block 4 (2001–3000 kWh)	326,02	12,72%	367,49	367,49	367,49	12,72%	
Block 5 (>3000 kWh)	336,60	12,72%	379,41	379,41	379,41	12,72%	
Winter Energy Charges							
Block 1 (0–500 kWh)	286,09	12,72%	322,48	322,48	322,48	12,72%	
Block 2 (501–1000 kWh)	311,47	12,72%	351,09	351,09	351,09	12,72%	
Block 3 (1001–2000 kWh)	325,37	12,72%	366,76	366,76	366,76	12,72%	
Block 4 (2001–3000 kWh)	336,61	12,72%	379,43	379,43	379,43	12,72%	
Block 5 (>3000 kWh)	346,36	12,72%	390,42	390,42	390,42	12,72%	
Basic Charges (<=50kVA)							
Service Charge (R/month)	612,47	12,72%	690,38	690,38	690,38	12,72%	
Capacity Charge (R/month)	587,21	12,72%	661,90	661,90	661,90	12,72%	

Basic Charges (>50kVA<=100kVA)							cost-reflective and supportive of the financial sustainability of the electricity undertaking.
Service Charge (R/month)	612,47	12,72%	690,38	690,38	690,38	12,72%	
Capacity Charge (R/month)	839,14	12,72%	945,88	945,88	945,88	12,72%	

11. Business Conventional Reseller	2023/24 Approved	% Increase	2024/2025 Approved	2024/2025 Redetermination Tariff	2024/2025 Recommended Tariff	2024/2025 Recommended % Increase	Analysis and Key Findings
Summer Energy Charges							
Block 1 (0–500 kWh)	278,71	2,79%	286,48	286,48	286,48	2,79%	The Business Conventional Reseller tariff was approved with energy charge increases ranging from 1.82% to 2.79% across the summer and winter consumption blocks, while the service and capacity charges increased by 12.72% for the 2024/25 financial year. The approved
Block 2 (501–1000 kWh)	306,72	2,52%	314,45	314,45	314,45	2,52%	
Block 3 (1001–2000 kWh)	322,05	2,39%	329,74	329,74	329,74	2,39%	
Block 4 (2001–3000 kWh)	334,11	2,29%	341,77	341,77	341,77	2,29%	
Block 5 (>3000 kWh)	345,22	2,21%	352,85	352,85	352,85	2,21%	

							tariffs are retained as the recommended tariffs, as they remain reasonable, cost-reflective and supportive of the financial sustainability of the electricity undertaking.
Winter Energy Charges							
Block 1 (0–500 kWh)	293,54	2,17%	299,91	299,91	299,91	2,17%	
Block 2 (501–1000 kWh)	320,10	2,00%	326,51	326,51	326,51	2,00%	
Block 3 (1001–2000 kWh)	334,64	1,93%	341,08	341,08	341,08	1,92%	
Block 4 (2001–3000 kWh)	346,08	1,96%	352,87	352,87	352,87	1,96%	
Block 5 (>3000 kWh)	356,61	1,82%	363,09	363,09	363,09	1,82%	
Service Charge (R/month)	630,48	12,72%	710,68	710,68	710,68	12,72%	
Capacity Charge (R/month)	604,49	12,72%	681,38	681,38	681,38	12,72%	

12. Agriculture	2023/24 Approved	% Increase	2024/2025 Approved	2024/2025 Redetermination Tariff	2024/2025 Recommended Tariff	2024/2025 Recommended % Increase	Analysis and Key Findings
Summer Energy Charges	235,61	12,72%	265,58	265,58	265,58	12,72%	

Winter Energy Charge	272,66	12,72%	307,34	307,34	307,34	12,72%	
Service Charge (R/month)	630,48	12,72%	710,68	710,68	710,68	12,72%	
Capacity Charge (R/month)	848,04	12,72%	955,91	955,91	955,91	12,72%	

13. Municipal/Robot Intersection	2023/24 Approved	% Increase	2024/2025 Approved	2024/2025 Redetermination Tariff	2024/2025 Recommended Tariff	2024/2025 Recommended % Increase	Analysis and Key Findings
Energy Charges	391,87	12,72%	441,72	441,72	441,72	12,72%	The Municipal/Robot Intersection tariff was approved at an increase of 12.72% for the 2024/25 financial year. The approved tariff is retained as the recommended tariff, as it remains reasonable, cost-reflective and supportive of the financial sustainability of the electricity undertaking.

14. Municipal Street light & Billboard	2023/24 Approved	% Increase	2024/2025 Approved	2024/2025 Redetermination Tariff	2024/2025 Recommended Tariff	2024/2025 Recommended % Increase	Analysis and Key Findings
Energy Charges	439,30	12,72%	495,18	495,18	495,18	12,72%	The Municipal Street Light and Billboard tariff was approved at an increase of 12.72% for the 2024/25 financial year. The approved tariff is retained as the recommended tariff, as it remains reasonable, cost-reflective and supportive of the financial sustainability of the electricity undertaking.

15. Industrial LV	2023/24 Approved	% Increase	2024/2025 Approved	2024/2025 Redetermination Tariff	2024/2025 Recommended Tariff	2024/2025 Recommended % Increase	Analysis and Key Findings

Summer Energy Charge	213,06	11,72%	238,03	238,03	238,03	11,72%	The Industrial LV tariff was approved with energy charge increases of 11.72% for both summer and winter energy charges, while the demand, reactive energy, service, and capacity charges increased by approximately 12.72% for the 2024/25 financial year. The approved tariffs are retained as the recommended tariffs, as they remain reasonable, cost-reflective and supportive of the financial sustainability of the electricity undertaking.
Winter Energy Charge	249,57	11,72%	278,82	278,82	278,82	11,72%	
All season Demand Charge (R/kVA)	318,31	12,72%	358,80	358,80	358,8	12,72%	
All-season Demand Charge (c/kVArh)	33,39	12,72%	37,64	37,64	37,64	12,73%	
Service Charge (R/month)	1050,79	12,72%	1184,45	1184,45	1184,45	12,72%	
Capacity Charge (R/month)	1604,65	12,72%	1808,76	1808,76	1808,76	12,72%	

16. Industrial MV	2023/24 Approved	% Increase	2024/2025 Approved	2024/2025 Redetermination Tariff	2024/2025 Recommended Tariff	2024/2025 Recommended % Increase	Analysis and Key Findings

Summer Energy Charge	198,89	11,72%	222,20	222,20	222,20	11,72%	The Industrial MV tariff was approved with energy charge increases of 11.72% for both summer and winter energy charges, while the demand, reactive energy, service, and capacity charges increased by approximately 12.72% for the 2024/25 financial year. The approved tariffs are retained as the recommended tariffs, as they remain reasonable, cost-reflective and supportive of the financial sustainability of the electricity undertaking.
Winter Energy Charge	235,41	11,72%	263,00	263,00	263,00	11,72%	
All-season Demand Charge (R/kVA)	297,53	12,72%	335,38	335,38	335,38	12,72%	
All-season Demand Charge (c/kVArh)	33,39	12,72%	37,64	37,64	37,64	12,73%	
Service Charge (R/month)	1260,93	12,72%	1421,32	1421,32	1 421,32	12,72%	
Capacity Charge (R/month)	6809,18	12,72%	7675,31	7675,31	7 675,31	12,72%	

17. Industrial LV (TOU) Large Power User	2023/24 Approved	% Increase	2024/2025 Approved	2024/2025 Redetermination Tariff	2024/2025 Recommended Tariff	2024/2025 Recommended % Increase	Analysis and Key Findings
Summer Energy Charges							
Peak	239,03	12,02%	267,76	267,76	267,76	12,02%	

Standard	179,96	12,02%	201,59	201,59	201,59	12,02%	NERSA notes that the approved tariff increases of 12.02% to 12.73% for the Industrial HV (TOU) Large Power User category remain reasonable. The approved tariffs are retained as the recommended tariffs, ensuring continued cost reflectivity and supporting the financial sustainability of the electricity undertaking.
Off-peak	138,33	12,02%	154,96	154,96	154,96	12,02%	
Winter Energy Charge							
Peak	568,79	12,02%	637,16	637,16	637,16	12,02%	
Standard	217,17	12,02%	243,27	243,27	243,27	12,02%	
Off-peak	148,79	12,02%	166,67	166,67	166,67	12,02%	
All season Demand Charge (R/kVA)	318,35	12,72%	358,84	358,84	358,84	12,72%	
All season Demand Charge (c/kVArh)	33,39	12,72%	37,64	37,64	37,64	12,73%	
Service Charge (R/month)	1681,25	12,72%	1895,11	1895,11	1895,11	12,72%	
Capacity Charge (R/month)	1503,11	12,72%	1694,31	1694,31	1694,31	12,72%	

18. Industrial MV (TOU) Large Power User	2023/24 Approved	% Increase	2024/2025 Approved	2024/2025 Redetermination Tariff	2024/2025 Recommended Tariff	2024/2025 Recommended % Increase	Analysis and Key Findings
							NERSA notes that the approved
Summer Energy Charges							

Peak	239,03	12,02%	267,76	267,76	267,76	12,02%	tariff increases of 12.02% to 12.73% for the Industrial HV (TOU) Large Power User category remain reasonable. The approved tariffs are retained as the recommended tariffs, ensuring continued cost reflectivity and supporting the financial sustainability of the electricity undertaking.
Standard	179,96	12,02%	201,59	201,59	201,59	12,02%	
Off-peak	138,33	12,02%	154,96	154,96	154,96	12,02%	
Winter Energy Charge							
Peak	568,79	12,02%	637,16	637,16	637,16	12,02%	
Standard	217,17	12,02%	243,27	243,27	243,27	12,02%	
Off-peak	148,79	12,02%	166,67	166,67	166,67	12,02%	
All season Demand Charge (R/kVA)	297,53	12,72%	335,38	335,38	335,38	12,72%	
All season Demand Charge (c/kVArh)	33,39	12,72%	37,64	37,64	37,64	12,73%	
Service Charge (R/month)	2311,74	12,72%	2605,79	2605,79	2605,79	12,72%	
Capacity Charge (R/month)	6429,40	12,72%	7247,22	7247,22	7247,22	12,72%	

19. Industrial HV (TOU) Large Power User	**2023/24 Approved**	**% Increase**	**2024/2025 Approved**	**2024/2025 Redetermination Tariff**	**2024/2025 Recommended Tariff**	**2024/2025 Recommended % Increase**	**Analysis and Key Findings**
							NERSA notes that the approved tariff increases of 12.02% to 12.73% for the
Summer Energy Charges							
Peak	239,03	12,02%	267,76	267,76	267,76	12,02%	
Standard	179,96	12,02%	201,59	201,59	201,59	12,02%	

Off-peak	138,33	12,02%	154,96	154,96	154,96	12,02%	Industrial HV (TOU) Large Power User category remain reasonable. The approved tariffs are retained as the recommended tariffs, ensuring continued cost reflectivity and supporting the financial sustainability of the electricity undertaking.
Winter Energy Charge							
Peak	568,79	12,02%	637,16	637,16	637,16	12,02%	
Standard	217,17	12,02%	243,27	243,27	243,27	12,02%	
Off-peak	148,79	12,02%	166,67	166,67	166,67	12,02%	
All season Demand Charge (R/kVA)	276,70	12,72%	311,89	311,89	311,89	12,72%	
All season Demand Charge (c/kVArh)	33,39	12,72%	37,64	37,64	37,64	12,73%	
Service Charge (R/month)	25325,25	12,72%	28546,62	28546,62	28546,62	12,72%	
Capacity Charge (R/month)	30160,00	12,72%	33996,35	33996,35	33996,35	12,72%	

20. Embedded Generators	**2023/24 Approved**	**% Increase**	**2024/2025 Approved**	**2024/2025 Redetermination Tariff**	**2024/2025 Recommended Tariff**	**2024/2025 Recommended % Increase**	**Analysis and Key Findings**
Residential Embedded Generator	85,50	12,73%	96,38	96,38	96,38	12,73%	The redetermined tariffs are identical to

Business & LPU Embedded Generators (<=1 MW)	70,85	12,72%	79,86	79,86	79,86	12,72%	the approved tariffs, indicating that the original tariff determination remains reflective of the cost structure and revenue requirements of the electricity undertaking.

21. City of Ekurhuleni (TOU)	2023/24 Approved Tariffs	% Increase	2024/2025 Approved	2024/2025 Redetermination Tariff	2024/2025 Recommended Tariff	2024/2025 Recommended % Increase	Analysis and Key Findings
Summer Energy Charges c/kWh							
Peak			242,04	242,04	242,04		This is the tariff at which City of Ekurhuleni and City Power Charge each other, as previously approved by NERSA for the direct supply of electricity of the few customers that are in City Power's supply area but supplied with electricity sourced from City of Ekurhuleni due to historic network configuration. The agreed tariff is Eskom Megaflex plus 10%. The increase in the tariff is therefore linked to the increase in the
Standard			172,23	172,23	172,23		
Off-peak			115,92	115,92	115,92		
Winter Energy Charge c/kWh							
Peak			704,57	704,57	704,57		
Standard			226,11	226,11	226,11		
Off-peak			131,09	131,09	131,09		
Notified Maximum Demand Charge (R/kVA)			53,25	53,25	53,25		
Utilised Demand Charge (R/KVA)			67,34	67,34	67,34		
Service Charge (R/Month)			13 460,96	13 460,96	13 460,96		
Administrative Charge (R/month)			6 067,33	6 067,33	6 067,33		
Reactive Energy Charge (c/kVArh)			31,13	38,61	38,61		

							underlying Eskom Megaflex tariff; however, the margin of 10% remains the same.

22. AEL	2023/24 Approved Tariffs	% Increase	2024/2025 Approved	2024/2025 Redetermination Tariff	2024/2025 Recommended Tariff	2024/2025 Recommended % Increase	Analysis and Key Findings
Summer Energy Charges c/kWh							
Peak			226,64	226,64	226,64		AEL is a customer directly supplied by Eskom but based in City Power's area of supply. The intention is to, in the near future, transfer the customer to take direct supply from City Power. In the meantime, an arrangement was entered into between the parties that AEL be charged Eskom
Standard			161,27	161,27	161,27		
Off-peak			108,54	108,54	108,54		
Winter Energy Charge c/kWh							
Peak			659,74	659,74	659,74		
Standard			211,72	211,72	211,72		
Off-peak			122,75	122,75	122,75		
Notified Maximum Demand Charge (R/kVA)			49,86	49,86	49,86		
Utilised Demand Charge (R/Kva)			63,06	63,06	63,06		
Service Charge (R/Month)			414,39	414,39	414,39		

Administrative Charge (R/month)			186,78	186,78	186,78		Megaflex plus 3%. The increase in the tariff is therefore linked to the increase in the underlying Eskom Megaflex tariff; however, the margin of 3% remains the same.
Reactive Energy Charge (c/kVArh)			29,15	38,61	38,61		

9. CONFIDENTIALITY

9.1. None.

10. CONCLUSION

10.1. From a conspectus of the facts and evidence presented to the REC, supporting information, stakeholder inputs and applicable legal framework, it is appropriate to consider and approve City Power's tariff application as set out in this Reasons for Decision document for the 2024/25 financial year

End.
