Technical Report

April 2025

ELECTRICITY PRICING AND SECTOR REFORM:

A Summary of Key Concepts and Strategic Questions

PRESIDENTIAL
CLIMATE COMMISSION
TOWARDS A JUST TRANSITION

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About this report

This report was prepared by SEA (Sustainable Energy Africa) to support the work of the Presidential Climate Commission (PCC) on its stakeholder engagements on electricity pricing and sector reform.

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This report was produced thanks to generous support from UK PACT (Partnering for Accelerated Climate Transitions).

UK PACT

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Executive summary

The electricity sector in South Africa is undergoing a fundamental transition. This report explores the pricing trajectory, and the intertwined system changes underway to achieve the goals of energy security, sustainability, equity and efficiency (affordability). It synthesises insights from technical studies, international case examples, and stakeholder consultations. The goal is to equip policymakers and social partners – including labour, industry, academia, civil society, and communities – to engage with the transition, with a focus on ensuring that the most vulnerable are not left behind.

Ensuring a least-cost, low-carbon electricity future is fundamental to economic development, climate response and long-term energy affordability. Electricity pricing is a critical lever for attracting investment. A reliable power system depends on sustained capital investment, which in turn requires predictable and adequate returns. In parallel, mechanisms must be in place for social inclusion through affordable access.

The South African electricity system is structurally unsustainable. Historic underfunding and an outdated structure have resulted in loadshedding, eroding economic growth. Eskom's debt, nearing R450 billion, represents a significant portion of sovereign debt. The distribution sector faces ageing infrastructure, ballooning municipal debt and deteriorating service reliability, alongside the rapidly escalating demands of managing growing distributed generation.

The electricity sector urgently requires substantial capital investment. However, the state cannot anchor the investments required. Electricity pricing must incentivise the needed investment for capacity expansion and modernisation by reflecting the real cost of electricity services and the value of electricity in real time.

Electricity pricing lies at the heart of the energy transition. The current model of recovering costs through average energy tariffs with inadequate fixed cost elements does not reflect new sector dynamics, leading to under-recovery and arbitrage – the ability to buy cheaply from outside of the regulated market, but pay the blended, or average price of the regulated market to balance supply needs.

Variable renewable energy (VRE) offers the least-cost energy path and addresses the critical local and global pollution challenges posed by our coal dependence, but fundamentally changes system economics. VRE is capital-intensive, with very low operating costs, and introduces variability that necessitates a more flexible and responsive energy mix. The growth of behind-the-meter generation and energy efficiency is reducing electricity sales, but fixed costs – related to infrastructure (grid and generation) investment and increased demand for system services – are rising.

Pricing reform must align with new system dynamics. A good tariff is one that sends a cost-reflective signal and elicits appropriate consumer behaviour. Customers buying from the market must pay the full costs they drive. This includes the system capacity held in reserve to balance their demand *in real time*. This is essential to ensure there is no shifting of these costs onto 'captive' customers (in the regulated market). Real-time pricing also provides a critical incentive to attract investment, value flexibility, and drive down prices through competition and innovation. The new system dynamics drive the urgent need for new pricing regimes that reflect real-time energy value and unbundled charges, ensuring that fixed capacity- and service-related costs are not absorbed into variable energy charges.

The introduction of a wholesale market is underway and can attract investment and deliver important efficiencies. With the promulgation of the Electricity Regulation Amendment Act (ERAA) and the establishment of the National Transmission Company of South Africa (NTCSA), South Africa is moving toward a competitive wholesale electricity market. Markets offer dynamic pricing, with the market price set at the point where supply meets demand, based on short-run marginal cost bids by all suppliers and load forecasts of buyers. The market ensures efficient dispatch of generation. The introduction of competition will drive efficiency, ensuring the lowest cost electricity for the country.

Investment risk in a market is spread across multiple suppliers, rather than being held by the state monopoly alone, and – by extension – the customers/taxpayers. More players within the system offer greater security of supply relative to a single (monopoly) company. VRE is highly scalable, with private investment in rooftop solar and utility-scale generation already underway. As a de facto market already exists, a market platform is needed to ensure these private players pay their fair share of system costs and do not shift them on to 'captive' customers.

Globally, 100-plus countries have undertaken unbundling and restructuring reform, including upper- and lower-middle income 'peer' countries, and all the (original) BRICS member countries (Brazil, Russia, India and China). While many different models have been adopted, they have all principally included unbundling of vertically integrated monopoly structures and the introduction of competition in generation *towards ensuring increased investment and security of supply*. Global evidence points to the market being critical for the rapid uptake of renewables required to meet the climate crisis and mitigate the impact of imminent international market carbon taxation, due to real-time pricing valuing the flexible resources required for a renewable-heavy system, and a market valuing lowest-cost technologies.

Reform is high-risk but necessary. Global experience indicates the risks associated with markets. Stakeholder concerns include privatisation of key economic assets, price spikes and volatility, private sector profiteering, renewable investment falling away as profit margins decline, and that critical social transfers are not protected. These concerns are being engaged through market design and associated policies in South Africa, but further engagement and vigilance is required.

South Africa is addressing risk in the market design, drawing substantially on global experience. The market will be phased in. While private competition will be introduced in generation, Eskom will continue to own generation assets and be a key part of the wholesale market (a 'pluralistic' market, i.e. private and public). Vesting contracts (securing a set price range) with Eskom in the initial years will smooth prices and mitigate exploitation of market dominance in price-setting. A combination of longer term, bilateral contracts (usually 5 – 20 years) and short-term (day ahead and spot) markets will support price stability. Transmission and distribution assets will remain public-owned, with required expansion supported through private investment, but transferred to public ownership. An asset-centric business such as the electricity supply industry (ESI) will always include a return on investment (or "profit"), whether state or privately owned. Regulatory oversight is required to ensure this is a fair return.

Achieving an operational market and market maturity is a complex exercise requiring institutional capacity and oversight that must still be developed. Effective market operation requires strong oversight, such as to ensure 'gaming' or collusion does not happen. Market evolution needs to be continuous and responsive. For example, exploring the best approaches to preserve policy goals, such as minimum price/price floors for renewable energy to meet carbon commitments. Outside of the market itself, wider electricity system issues must be addressed, or they will collapse the market. Critically, the issue of non-payment, or structural debt, must be addressed. System inefficiencies resulting from a lack of system visibility create costly imbalances and institutional capacity must be developed to reduce this.

Municipal distributors play a key role in reform but face severe challenges. Municipalities account for nearly half of electricity sales. Hence, their participation as buyers in the wholesale market is important for effective competition. However, most face severe financial, regulatory and capacity limitations. Initially, direct participation in the market will be very limited, but should increase over time. Indirect participation will be facilitated through an entity that trades on their behalf – a public entity set up for this purpose (could be another utility or grouping of utilities), a private trader or a 'supplier of last resort', such as Eskom Distribution.

The sale of electricity by distributors to their customers will continue to be regulated. Most – smaller – customers will continue to buy electricity from their municipal utility or Eskom Distribution. Distribution utility tariff structures will need to evolve to better reflect the new market dynamics, including greater fixed charges, but will need to balance cost reflectivity with customer retention on the grid and affordability. Tariffs should also incentivise flexibility – to reduce load or discharge stored energy at times of limited supply (and/or high cost) to achieve efficiency and drive down costs. However, in the main, 'captive' customers will be buffered from volatile market prices through regulated retail tariffs based on the current average cost approach. Therefore, for ordinary customers, not much should change.

The gap between the wholesale market price and regulated retail price can lead to systemic financial shortfalls that must be addressed. Suppliers of wholesale electricity must be paid, requiring the system to facilitate this 'deferred payment', i.e. the 'gap' between the wholesale price and the regulated tariff payment. This, alongside non-payment risks, requires a well-developed understanding of the structural debt in the system and mechanism/s to address this, through hedging and subsidies.

Reform of the electricity distribution industry (EDI) is urgently required to enable municipal market participation, ensure cost recovery, and support investment in grid reliability and flexibility. Distributors (municipalities and Eskom Distribution) have two roles that need to be functionally separated: the 'wires' (maintaining the network) and 'retail' (selling electricity) business functions. Separating these business elements will help to ensure cost recovery on all services. This is the first step of EDI and tariff reform and is required regardless of wholesale market reform. Over time, this will enable more responsive (potentially consolidated) 'future-ready' EDI formations to emerge, whilst retaining their public ownership.

The success of the market model and protection of social equity requires complementary reforms. This includes review of the Electricity Pricing Policy and the National Subsidies Framework (both are underway), at a minimum. Municipalities must be enabled to participate in the market – current financial regulations, in particular the Municipal Financial Management Act (MFMA), inhibit this.

Access to basic electricity services has been a cornerstone of government policy post-democracy, but is breaking down. Indications are that the gap between the cost to serve and what people can afford to pay represents ~R30 billion per annum. The Electricity Pricing Policy made provision for this through the Local Government Equitable Share (LGES) grant, which makes provision for ~R15 billion to support free basic electricity services (FBE); and below-cost tariffs enabled through cross-subsidy from high-consuming electricity customers (~R15 billion). However, the portion of LGES allocated by local municipalities to FBE has declined substantially. In addition, cross-subsidy is unevenly spread across municipalities and is under threat.

Understanding the dynamics at play around the affordability-revenue gap is critical to addressing structural debt and sector sustainability. Increasingly stringent indigent registration requirements, and the shift of LGES to other municipal service revenue gaps (notably water), has reduced funding for FBE. The reliance on cross-subsidy to meet the 'affordability gap' is potentially larger than anticipated, and uneven and inequitable, i.e. dependent on 'customer mix'. The ability to draw on cross-subsidy is also under threat where cross-subsidies are non-transparent and held in variable energy charges. These can be avoided by customers reducing their energy consumption (through rooftop solar or efficiency). Alongside tariff increases well above inflation, the outcome has been rising losses at distribution level and non-payment to Eskom and/or 'cannibalisation of infrastructure', i.e. monies collected for asset refurbishment are spent covering electricity wholesale purchases.

Competition drives the cheapest price pathway, but electricity prices must increase to address historic underinvestment, new capacity required and transition readiness. Ensuring long-term sustainability of the ESI will require substantial tariff increases, even before wholesale market reforms take effect. While the introduction of a wholesale market should introduce some efficiencies in electricity costs, there are many factors that will continue to drive these costs upward in the future. An indicative increase of 8 – 28% in nominal terms is required just to accommodate current under-funding in the ESI. Further increases will be needed to accommodate capacity expansion and grid modernisation.

Electricity tariffs are already unaffordable for many South Africans, and without mechanisms to address this, we will see year-on-year increases that are socially and economically untenable. Strengthening governance and improving system performance must be central to sector reform. At the same time, future readiness and innovation must be embraced to ensure long-term sustainability. These efforts must be underpinned by well-designed, effective subsidies anchored in a policy vision that delivers a truly inclusive 'grid for all'.

Reform work is underway across the electricity supply system. The insights and recommendations presented aim to support broad understanding and alignment of these efforts around the central role of pricing in an inclusive transition.

Key recommendations include:

- **Implement tariff reform**. A market is under development that will introduce dynamic pricing of electricity supply and generation capacity at the wholesale 'pricing gate' – attracting critical investment required. The regulated retail 'pricing gate' should reflect these new dynamics, unbundling tariffs to reflect different services and establishing (or adjusting existing) fixed and variable cost components and time-of-use structures, *where appropriate*. This should be based on ongoing improvements in costing data, and NERSA guidelines to support standardised approaches and performance benchmarking.
- **Support an efficient market to achieve the cheapest electricity mix and manage risk.** Strong market oversight and mechanisms to manage volatility will help address risk. Municipal distribution utility participation must be supported through EDI reform and capacity development, towards greater market liquidity. At the same time, many municipal utilities will not participate directly and the role of the "supplier of last resort" requires urgent clarification. A mechanism for deferred payment, to ensure suppliers are paid at times when revenue does not cover cost (due to non-payment or a lag between wholesale purchase and vesting contract settlement), is important to cover the gap between the dynamic market price and the regulated average tariff.
- **Invest in grid modernisation** at both transmission and distribution level. Invest in digital infrastructure for real-time grid management and demand-side flexibility. This should support demand forecasting, and load flexibility, which minimises market inefficiencies (need for greater reserve) and balancing penalties. This is critical to keeping value chain costs down.
- **Reform municipal utilities** through stabilising EDI operations (drawing on work/experience of the Metro Trading Services program the National Treasury City Support Unit). Systemic debt must be addressed alongside governance issues, including security aspects (criminal enterprise undermining revenue collection and infrastructure). Functional separation of the wires and retail business elements is foundational to tariff reform and distribution sector sustainability. Build capacity to engage in energy trading (where appropriate) and load forecasting (critical for all). EDI reform must enable municipalities to engage with electricity sector functions in line with capacity and strategy.
- **Consider increased funding for the ESI**, guided by policy that considers new system dynamics. This may require a greater proportion to be raised through the tax base, consideration of local property taxes (for distribution grid costs) and how to draw on cross-subsidy in a manner that is more equitable. Subsidy scale and mechanisms need to be fair and sustainable; and require a deeper understanding and further analysis of the 'moving parts'.

- **Build institutional capacity**, particularly regulatory capacity, but also including civil society, to oversee new market structures, enforce rules, and protect consumers, and ensure municipalities and other market participants are equipped to engage effectively. Capacity at the distribution utility must be enhanced and far greater emphasis placed on performance-based pricing – and the enforcement of license conditions.
- **Strengthen political leadership** to be able to support constituencies – tariffs are highly political.

South Africa's electricity transition is unavoidable and urgent – and underway. Managed well, market and pricing reform can drive decarbonisation, improve reliability, and unlock investment to achieve energy security and keep electricity as cheap as possible. Managed poorly, it could deepen inequality, entrench system collapse, and delay economic recovery. This report provides the foundation for stakeholders across government, industry and civil society to navigate this transition and ensure that no-one is left behind.

Acronyms and abbreviations

CPA	Central Purchasing Agency
EDI	Electricity Distribution Industry
EPP	Electricity Pricing Policy
ERAA	Electricity Regulation Amendment Act
ESI	Electricity Supply Industry
FBE	Free Basic Electricity
INEP	Integrated National Electricity Program
IPP	Independent Power Producers
LGES	Local Government Equitable Share
MFMA	Municipal Financial Management Act
MV	Medium Voltage
NERSA	National Energy Regulator of South Africa
NTCSA	National Transmission Company of South Africa
PPA	Power Purchase Agreement
PV	Photovoltaic
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme
TSO	Transmission System Operator
USDG	Urban Settlements Development Grant
VRE	Variable Renewable Energy

Document overview and introduction

South Africa is undergoing a profound and complex transformation of its electricity sector. This transformation, while aligned with global trends, is intensified by local challenges; chief among them being historic underinvestment in infrastructure, an outdated structure (vertically integrated monopoly), Eskom's financial instability, and persistent electricity supply shortages. As a result, the sector must attract substantial new investment to restore reliability and meet future energy needs.

However, South Africa's fiscal constraints, coupled with Eskom's unsustainable debt levels, mean the public sector alone cannot shoulder the required investment. Two critical reforms are therefore necessary: first, the establishment of a competitive wholesale electricity market to enable private investment; second, a fundamental restructuring of electricity tariffs to ensure full cost recovery across the system.

These imperatives introduce significant pricing challenges. As investment increases to achieve reliability, and modernise and expand the electricity system, overall sector costs will rise. This reality must be balanced against the country's high levels of poverty and inequality, which demand that electricity remains accessible and affordable. The energy transition – and necessary market reform to achieve this – will ensure the cheapest electricity path in the future. In addition, the electricity supply industry (ESI) must allocate costs in a manner that reflects underlying system dynamics, while also being socially and politically acceptable. Mechanisms to support vulnerable consumers have been built into the pricing architecture. These require review in light of sector transitions.

There are multiple ways to design markets and recover costs, each with advantages and disadvantages. There are also transition pathways from one system to the next. Each pathway has implications for value chain players and consumers. With the promulgation of the Electricity Regulation Amendment Act (ERAA) and prior regulatory reforms, South Africa has set out on a particular route. The consequences and complexities of these pathways, particularly for consumers, are understood only by a few inner-circle experts.

President Cyril Ramaphosa's Energy Action Plan was launched in July 2022 to address electricity supply industry challenges. It is structured around five pillars aimed at eliminating loadshedding and restoring energy security. The fifth pillar, focused on market reform and pricing, provides the foundation for this paper. It seeks to clarify the systemic changes required and establish the scale of the challenge, including the indicative tariff trajectory, and the gap between the revenue required to serve poor households and what they can afford to pay. It aims to provide an accessible synthesis for stakeholders who need to prepare for, and engage with, this evolving system. Specifically, the paper will:

- Outline the electricity value chain, associated costs, and funding mechanisms.
- Explain the rationale for market reform and market design options.
- Describe South Africa's current reform trajectory and its implications.
- Analyse full electricity cost components and future price trajectories.
- Explore just transition concerns around accessibility and affordability.

- Discuss options for cost recovery through a mix of tariffs, transfers, and taxes.
- Highlight enabling reforms required in adjacent systems, particularly municipal entities.
- Identify roles and responsibilities of different actors in managing market risks and opportunities.

This paper draws on six technical studies and stakeholder engagements. It aims to support work underway on Eskom's unbundling, market platform development, Electricity Distribution Industry (EDI) reform, and broader Just Energy Transition and subsidy policy reviews. Centrally, it aims to empower social partners – labour, industry, civil society, and communities – to engage meaningfully in electricity reform processes, guided by a central question: Where is the consumer in this transition, and how can we ensure that no one is left behind?

1 What drives electricity supply industry (ESI) costs and how are these funded?

1.1 What does it cost to supply electricity in South Africa?

Electricity supply is typically categorised into three functions: generation, transmission and distribution. This includes building and operating power plants and networks, ensuring real-time balancing of supply and demand, and market elements such as contracting, metering and billing.

The primary drivers of cost are **capital investment costs** and **operating costs**. Capital costs include depreciation and cost of finance, and a return on assets sufficient to sustain, expand and modernise the system. Operating costs are largely driven by fuel, salaries, wages and maintenance.

In 2022/23, Eskom and municipalities incurred R330 billion in operating expenditure, with the lion's share in generation (Walsh, 2025). Primary energy drives these costs, followed by employee and capital costs. Transmission is a small element, at 4%, with distribution contributing 19% to the value chain, split relatively evenly between Eskom and municipalities.

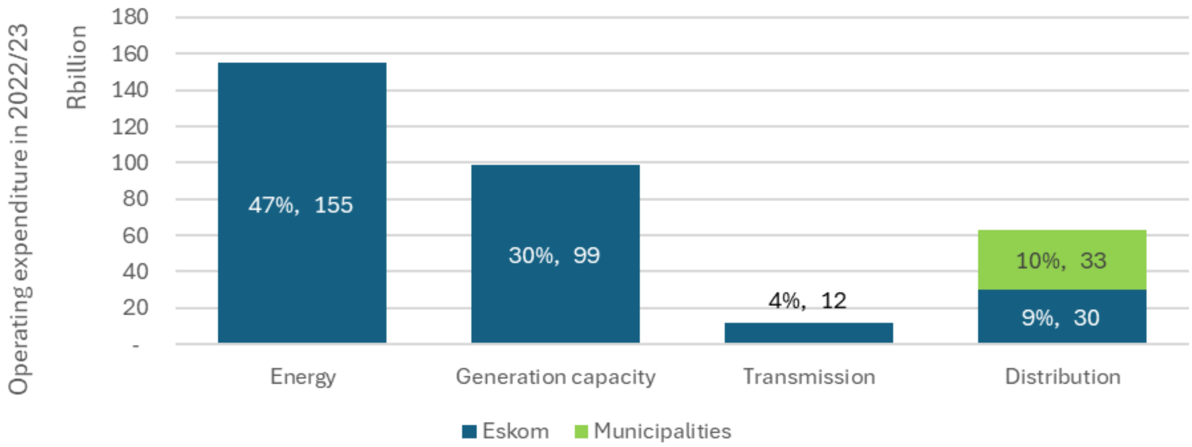


Figure 1. Operating expenditures incurred by Eskom and municipal electricity distributors in 2022/23 classified by function. Source: Walsh, 2025

System cost pressures driving above-inflation increases in 2024/5 are rising coal prices, high operational and maintenance costs of aging plants, running expensive peaking plants, and ongoing special pricing agreements with certain industries.

Municipal distribution 'add on' costs (over and above bulk purchase) are comprised of employee-related costs (27%), capital and finance costs (34%), and 'other' costs (39%) (Walsh, 2025). The capital and finance costs include interest owed on debt to Eskom, which is 11% of the total. 'Other' costs include maintenance, but the precise share that is maintenance is uncertain. Analysis of municipal cost elements is difficult due to inconsistent reporting.

Understanding how the underlying functions drive costs, how these costs are structured, and how they are evolving is critical to grasping why pricing reform is necessary.

1.2 How is the ESI funded?

A viable electricity system must recover its full costs to fund maintenance and refurbishment *and* collect a sufficient return on investment (surplus) to fund system expansion and innovation. Electricity has two revenue collection 'stage gates': the wholesale market (generation and transmission costs) and the retail market (distribution costs). There are only three sources of funding ('revenue'): tariffs, transfers and/or taxes.

Tariffs are regulated charges levied on customers in exchange for electricity services. These are the primary source of funding for the ESI in South Africa, making up more than 95% of all sector funding (Walsh, 2025) – *placing pricing at the heart of sector reform.*

Cross-subsidy, embedded in tariffs (e.g. from high- to low-income customers) are a crucial but often invisible part of system funding.

Transfers include grants and subsidies, but also bailouts from national to local government or utilities. The Local Government Equitable Share provides grant monies in support of free basic electricity.

Taxes underpin the transfers described above, but there is limited direct application to ESI funding[1].

1.3 How are tariffs set?

Electricity tariffs in South Africa are determined through a regulated process based on the **revenue requirement** formula, which provides average cost pricing:

Tariff = (prudent expenditure[2] – non-tariff revenue[3])/forecasted sales (demand for services).

The National Energy Regulator of South Africa (NERSA) reviews whether utility expenditures are prudent and efficient, whether sales forecasts are realistic, and whether cost allocations to customer groups are justified (based on cost of supply studies). They also review tariffs and whether these are in line with the tariff principles and approaches contained within the Electricity Pricing Policy (EPP)[4]: cost-reflectivity, transparency, non-discrimination, predictability/stability, revenue adequacy, affordability, economic efficiency, cross-subsidisation (that these are transparent and within limits), cost allocation unbundling, and investment support.

[1] Municipal businesses may fund a shortfall in revenue through rates and taxes. This is usually where the municipality has not recovered sufficient revenue to cover costs, but this approach has also been used proactively to reduce the incentive to go 'off-grid', where some of the fixed connection charge is considered to be part of the property value.

[2] Prudent expenditure is spending that is wisely managed, to avoid waste and ensure resources are used effectively.

[3] Non-tariff revenue would include grants or items such as development levies.

[4] Currently under review.

Tariffs are composed of charges at the **wholesale** level (energy, capacity, transmission) and at the **retail** level (distribution, billing, administration). Municipal and Eskom distribution/retail tariffs are calculated based on their respective cost structures, but both need to also include costs passed down from the wholesale level.

1.4 Understanding the cost elements in tariffs

Electricity tariffs must reflect the diverse drivers of system costs, when considering *demand for services*. The system currently has two pricing 'stage gates': wholesale and retail. Historically, Eskom Transmission sold wholesale energy services, but this has transitioned to the National Transmission Company of South Africa (NTCSA); a subsidiary of Eskom that will eventually transition to that of a fully independent transmission system operator and market operator. Eskom Distribution and municipalities are involved in retail, i.e. on-selling electricity to customers.

Table 1. Simplified schematic of system cost drivers reflected in electricity tariffs

Cost element	Wholesale cost driver	Retail cost driver	Pricing
Energy	Volume of electricity used, costs based on generation technology (e.g. wind, solar, coal, gas)	Pass-through wholesale cost	Variable (R/kWh)
Generation capacity	Dispatchable power held in reserve for reliability (may not deliver actual energy)	Pass-through wholesale cost	Fixed (R/kVA or R/day)
Transmission capacity	Distance electricity is transported; maximum capacity available to a large customer, e.g. retailer, big industrial user, etc.	Pass-through wholesale cost	Fixed (R/kVA)
Distribution capacity	N/A	Maximum capacity available to a customer, based on connection size.	Fixed (R/kVA)
Distribution demand	N/A	Maximum capacity used by a customer within a month, i.e. maximum instant demand placed on distribution grid.	Fixed (R/kVA)
Service & admin	N/A	Billing and metering	Fixed (R/day)

The energy charge represents a charge for electrons generated and consumed. It increases or decreases a bill based on the amount of electricity a customer uses. Billing and metering costs are fixed, since they do not vary by the quantity of electricity consumed. The capacity charge is more complex. This represents the amount of power the system needs to meet a customer's demand at a particular point in time. This is a function of having sufficient power stations to meet the maximum demand in any day (reserve capacity), and the size of the network and related connections to deliver the power required at any one moment. This underpins the reliability of the power system.

As behind-the-meter generation investments grow, energy use decreases, but demand for system capacity, especially at peak times, often remains the same. In addition, investment into new flexible grid services is required to respond to the variable renewables (both rooftop and utility-scale) – flexible services are usually more costly. A more flexible system also requires new skills and management. Decreased sales therefore does not mean a decrease in utility staff requirements. End-user tariffs must reflect the underlying cost dynamics, or they will fail to recover costs adequately.

2 Pricing at the heart of sector reform

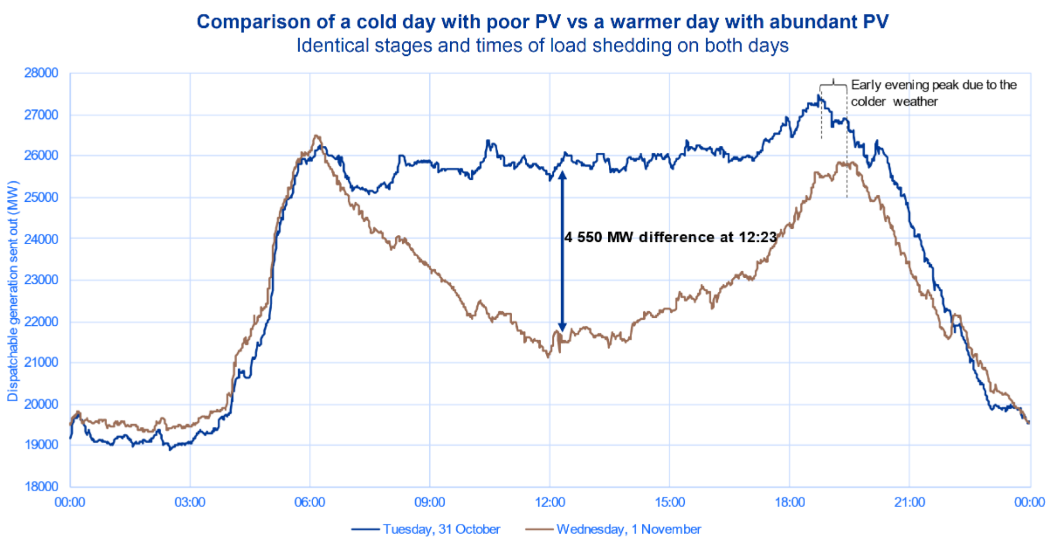
Electricity pricing and market design are not just technical matters, but require some choices about allocating risk among stakeholders. Global energy disruption exposes the current pricing system's weakness: price signals based on average cost fail to capture the real-time value of energy, and where fixed system costs are insufficiently ringfenced and charged in the volumetric energy tariff this creates a risk of under-recovery at both the wholesale and retail level.

2.1 Disruptions to traditional ESI costs and revenue

Electricity systems globally are shifting from centrally planned, supply-driven models to flexible, demand-oriented systems. This transformation is largely driven by the rapid rise of variable renewable energy (VRE), energy storage, and smart technologies, which enables decentralised and prosumer[5] participation.

The global transition is driven by efficiency, environmental sustainability and human health considerations. In developing countries, additional drivers include grid reliability and/or access. It offers the cheapest energy in the long run and greater opportunities for wider participation in the industry (democratisation). The disruptions to traditional cost and pricing models manifest as follows:

Behind-the-meter generation and energy efficiency investments erode sales and cross-subsidies. Rooftop PV and other embedded generation, alongside a revolution in energy efficiency, reduce sales from the grid and changes load profiles: customers rely on solar during the day but still draw heavily from the grid during evenings and early mornings, creating a load profile "duck curve" (Figure 2). While grid electricity consumption (sales) declines, capacity costs remain high. Many network capacity costs and subsidies are bundled into unit (energy/kWh) charges, eroding revenue. As wealthier users install their own generation, they avoid these charges, increasing the cost burden on the remaining customers.



Maximum/Installed Rooftop PV (MW):	Total
Jan-25	6,177.50
Dec-24	6,165.20
Nov-24	6,165.20
Oct-24	6,165.20
Sep-24	6,141.40
Aug-24	5,952.60
Jul-24	5,952.60
Jun-24	5,790.50
May-24	5,565.30
Apr-24	5,490.00
Mar-24	5,439.90
Feb-24	5,439.90
Jan-24	5,412.30
Dec-23	5,203.70
Nov-23	5,039.60
Oct-23	5,005.00
Sep-23	4,883.00
Aug-23	4,812.80

Figure 2. Rooftop PV impact. *Source: NTCSA, 2024*

[5] A customer who consumes and produces electricity.

VRE systems shift the balance from variable to fixed costs. VRE systems are capital-intensive (higher upfront investment) but have low operating costs (marginal costs of production[6]), changing the fixed to variable structure of the energy charge. Further adding to this are the investment costs in grid expansion and adaptation from integrating VRE systems: new transmission lines are needed to reach renewable generation zones and distribution networks must handle bi-directional energy flows. Fixed costs are rising while volumetric revenue is declining – a mismatch that current pricing structures fail to resolve.

2.2 Why average costing breaks down

In a state-funded monopoly system, the energy mix is decided through a central planning exercise (the Integrated Resource Plan) with energy determinations based (in theory) on a cost optimisation model (based on levelised cost of energy[7]). System operation dispatches power plants using a **merit-order** model (dispatching lowest-cost generation first). The costs of large, fossil-fuel power stations are relatively stable, and customers are 'captive'[8]. Tariffs are regulated and based on costing methods that – for both wholesale and retail – use an average costing approach, i.e. a tariff based on total costs divided by anticipated unit sales. It is obviously more complicated than this – costs are allocated based on how the consumption patterns of customers groups 'drive' these costs and include energy, demand and even, for larger customers, time-of-use pricing.

Average costing provides predictability and stability, smoothing real-time fluctuations over time. However, long-term average pricing has limitations in a changing system where costs vary by time of day (and location), power production is increasingly intermittent, and customer behaviour is dynamic and less predictable. **Fixed costs make up around 50% of total system costs**[9]. Currently these are largely recovered through volumetric tariffs (R/kWh), which (along with cross-subsidies in the system) are vulnerable to declining sales. Therefore, it is considered optimal that costs for fixed and variable expenditure are split and recovered separately. The consequence is that fixed charges will need to increase, particularly for users with high capacity demands but low consumption.

Further, the average price fails to reflect the **real-time value of electricity**. The cost of generating electricity varies according to technology and its responsiveness (or "dispatchability"). Technologies that can switch on or off quickly in response to changes in demand (typically used at peak time) cost more. As variable renewable energy (VRE) penetration increases, price fluctuations will intensify, with the abundant midday solar realising low or even negative prices, and evening peaks with limited supply resulting in price spikes.

[6] The incremental cost of producing an additional unit of electricity.

[7] The average cost per unit of electricity (typically in R/kWh) generated over the lifetime of a power plant, accounting for all capital, operating, and maintenance costs, divided by the total electricity produced.

[8] A consumer who has no choice but to purchase electricity from a specific utility or supplier.

[9] This is informed by an analysis of electricity supply industry costs across Eskom and municipalities by Walsh, 2025. Yet Eskom indicates that its fixed costs are greater than 70%. Therefore, this share of fixed costs is indicative only. This is likely to be an area of contention going forward. Therefore, this area would require further in-depth research/analysis.

Average prices in this changing context results in underinvestment in flexible capacity, and creates arbitrage opportunities ("gaming the system") for those with access to capital, i.e. such consumers may benefit from the cheap supply of VRE through bi-lateral contracts, but when they need to use the backup supply of the grid, they pay the average price and not the real cost to produce electricity to meet their demand at that time (Figure 3). **Real time pricing** is needed to reflect these dynamics and encourage demand and investment responses.

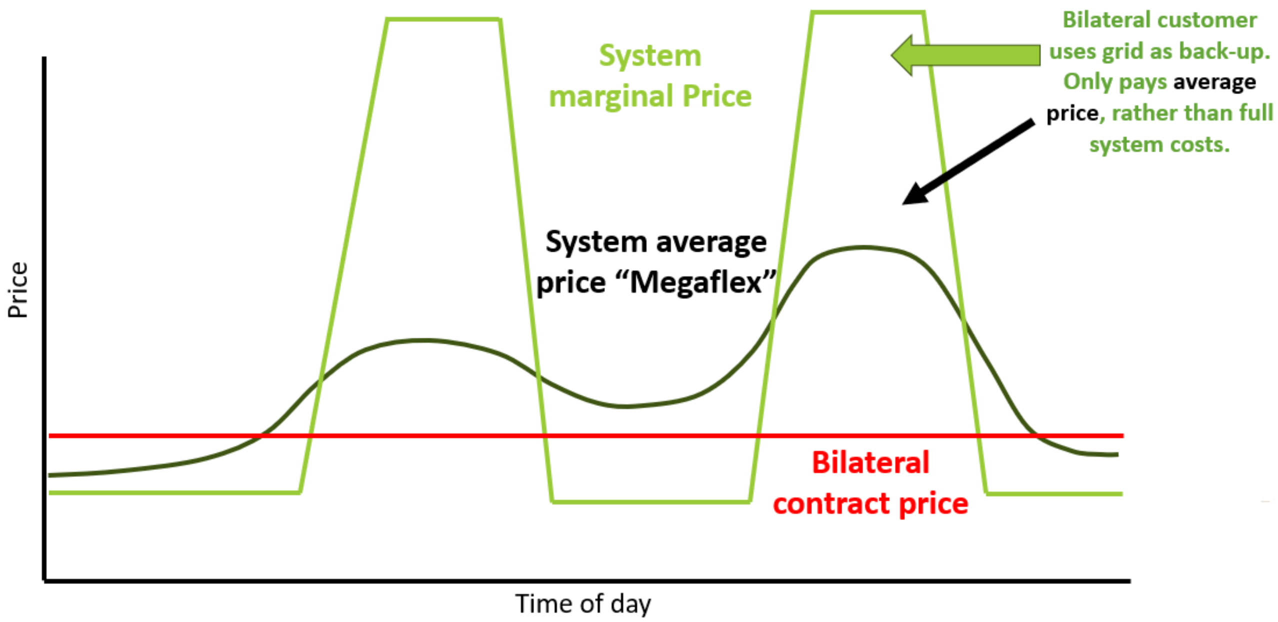


Figure 3. The need for dynamic pricing.

These pricing shifts (real-time pricing and greater level of fixed charges) have equity implications that must be addressed. Wholesale pricing shifts will need to be reflected in tariffs at the retail end. Wealthy customers may leave the grid if fixed charges are perceived as excessive. This is a sub-optimal outcome, as the national network system costs are now carried by a smaller group, and the investment on the consumer side is also usually less efficient. Low-income customers cannot absorb high fixed fees, and they often have limited ability to adjust to time-of-use price signals, meaning these tariffs would be punitive. These costs must be subsidised, in line with subsidy and pricing policy.

The future pricing structures must reflect the shift from commodity (kWh) to services (grid availability, etc.). It is not just the cost to produce electricity that matters, but the **value of electricity in real time**, reflecting the elements of capacity (R/kVA), flexibility and system reliability (dispatchable power, often gas), and balancing and grid services (reactive power, spinning reserves, etc). Without reform, South Africa risks a grid collapse under declining revenues and rising fixed costs, with the poor and most vulnerable paying the price. At the same time, these pricing shifts must be balanced with protective measures for poor and vulnerable consumers.

2.3 Pricing mechanisms and market design choices – allocating risk ("who pays")

Electricity pricing and market design are not just technical matters but require choices about allocating risk among stakeholders. These include investment risk, demand and supply forecasting errors, price volatility and cost recovery. The structure of the market determines who bears which risks: the state, private investors, utilities, or consumers. Many of these “choices” are limited or directed by external constraints or realities, notably how much risk the state can shoulder.

A market design and pricing mechanism that recovers costs through a consistent average fee has the advantage of being highly predictable and stable for consumers, and easier to administer, but has the disadvantage of discouraging efficiency and innovation at peak times (when you would like to reduce consumption), masking the true cost of flexibility and capacity, and often requires ‘captive’ customers to absorb shifted costs of those who can arbitrage to gain efficiency outside of the system; and the state to absorb inefficiencies through bailouts or subsidies. Investment into this system is through state auction, as there is no price signal to attract capital.

In competitive markets, pricing is central in driving investment and efficiency. When power sources vary in the short run (wind, solar) and supply is constantly changing (resulting in the value of energy changing from hour to hour), a market design that allows a fluctuating price drives efficiency and flexibility by reflecting the actual cost of producing and delivering electricity at a given moment. On the other hand, it is volatile and complex; requiring advanced forecasting and market participation skills, which many stakeholders (e.g. municipal distributors) may lack.

3 Why markets and how do they work?

3.1 Motivations for change

A well-functioning, vertically integrated, state-owned monopoly utility has advantages: full supply chain control and economies of scale can bring prices down, and integrated planning can prioritise policy goals (e.g. universal access, low carbon), and balance supply and demand. On the other hand, state-owned, vertically integrated utilities may mask inefficiencies, delay investment, reduce transparency and begin to have undue influence in a country. Typically, when these disadvantages manifest, the system becomes vulnerable to political interference, corruption and underinvestment, as national fiscal constraints limit large-scale spending.

This is visible in events unfolding in South Africa: historic underinvestment resulted in critical capacity shortages, where the unserved energy for 2023 amounted to approximately 7.5% of total system demand (Van der Merwe, 2025). The reality is that South Africa recovers the costs of electricity provision through large bailouts of Eskom and of municipalities, with a large portion unrecovered, resulting in a vicious cycle of ballooning debt, underspending on maintenance, and little new investment.

These disadvantages, combined with global energy system disruptions and trends driven by global climate change policy, have caused utilities around the world to move from vertically integrated systems to more market-based systems, shifting from a supply-side orientation to flexible systems built around demand.

South Africa faces three non-negotiable imperatives: (1) to attract investment to expand capacity and restore reliability; (2) to ensure affordability through lowest cost system; and (3) to align prices with actual system costs, while maintaining access and social equity.

Without reform, investment will remain insufficient, Eskom's dominance will stifle innovation, the grid will deteriorate as wealthier customers defect, and the affordability burden will fall on the poor and the state – as will the burden of persistent economic stagnation and decline.

A market mobilises capital and drives down costs through competition by dispatching lowest-cost generation. It ensures cost recovery (at the wholesale level), as pricing is aligned with real costs, supporting financial sustainability. This transition reflects a fundamental shift from centrally planned, supply-led systems to **demand-responsive, investment-driven markets**.

3.2 Market design pathways

Electricity markets can be designed in various ways. Debate should focus on how they should be structured to ensure both reliable supply and efficiency, i.e. the lowest possible future price path. Globally, countries tend to follow one of three main market models:

Centralised Dispatch: The *system operator* decides which power plants generate electricity and when – based on price bid into *central market*. This model provides grid stability and clear control, but limits competition and innovation.

Decentralised (Self-Scheduled): *Individual generators* decide when to produce, based on price bid into a (usually) *central market*. The system operator manages the consequences (maintains grid stability). This system resembles South Africa's current context of bilateral contracts (decentralised decisions), but with an additional spot market system overlay. A decentralised model encourages competition and flexibility, but it also leads to more price volatility.

Hybrid Models: A combination of both. Some generators are centrally dispatched, while others operate independently. This approach aims to balance the stability of centralised systems with the innovation and efficiency of market-based models.

Each model has trade-offs. Decentralised markets appeal more to private investors because of their transparent pricing, but they are more complex and less stable. Centralised systems are simpler and more secure but may slow down innovation. Hybrid models provide a balance of these approaches and can evolve. They are often used during transitions to full market liberalisation. In Norway, at the launch of the market platform, 90% of the market was in physical bilateral agreements (long-term power purchase agreements), with only 10% represented in the Day Ahead Market. Today the market trading volume is well above 90%.[10]

Lessons from liberalisation failures of the 1990s in the developing world indicate that a successful market outcome can include both state and private actors, dominance by any one player must be avoided, and the system must be carefully designed to suit local conditions (Foster & Rana, 2020). As South Africa introduces a wholesale electricity market, the shift will be from long-term government-backed contracts to shorter-term trading. The market will not, however, mean the privatisation of state assets, as Eskom Generation will be a market participant and all transmission and distribution assets will remain public owned.

Market reform is essential to attract private capital for new capacity expansion and, through competition, drives efficiency and allows electricity prices to reflect real-time conditions. However, it comes with substantial risks that must be addressed. Market design can address some of this risk.

Price volatility and price spikes, due to demand and supply imbalances, is a significant risk, impacting affordability and consumers in general – as well as being an investment risk. A suite of mechanisms can be deployed to mitigate this. Long-term contracts and Power Purchase Agreements (PPAs) provide price stability by locking in fixed prices, reducing exposure to market volatility, as exposure is only on the difference between market price and contract price. Hedging contracts (or other similar financial instruments: futures and options) work in a similar way. A market may also introduce regulated price caps and floors that protect consumers from extreme price spikes and ensure reasonable returns for investors. If the market does not deliver the capacity or grid services required, or if price stability is required, state auctions can be undertaken.

[10] Figures for trading volumes available through the Nord Pool website (https://www.nordpoolgroup.com/en/) and total production can be sourced via the Regulatory Authority (https://www.nve.no/norwegian-energy-regulatory-authority/).

Risk mitigation, essentially an insurance cost, comes at the cost of system efficiency. These mechanisms also require sophisticated financial instruments and market transparency. Whether it is the private sector (hedging) or the state (price caps), these costs will usually filter down to the consumer, directly in tariffs or indirectly as economic costs.

A strong regulatory framework, beyond market design, is essential and must address our local context. Clear policies and competent institutions are needed to prevent market manipulation and build trust among investors and the public. The poor must be shielded from price volatility and the shift toward fixed charges and time-of-use pricing. To do this, social support mechanisms should be defined outside of the technical market rules, within policy, and provided through grants, direct subsidies or transparent cross-subsidies that sit within system fixed costs.

There are also unique barriers to be addressed, particularly in relation to institutional weaknesses. Regulatory capacity and the independence of the transmission system operator are critical to ensure oversight. Municipalities, who are key players in electricity distribution, lack the skills, tools and financial stability and regulatory frameworks to operate in a real-time market. Non-payment risks by municipal distributors could place massive strain on the system, as seen in countries like Mexico and India (Geddes et al., 2020). The system must enable recovery of higher costs to ensure capacity expansion and system reliability – or we risk ongoing economic decline. This is politically challenging and requires concerted national leadership and planning.

4 How pricing dynamics drive market evolution – and how this may look in South Africa

4.1 How prices are set in competitive markets

In competitive electricity markets, prices are typically determined in a day-ahead market using short-run marginal cost pricing. This allows the market to send dynamic price signals that guide investment in energy generation and system flexibility. The process works as follows:

1. **Buyers** (such as distributors, traders, or large users) **forecast expected electricity demand**, often in hourly or even shorter intervals.
2. **Generators submit offers** (bids) to sell electricity for each interval, typically based on their marginal (operating) costs. These may be offers into a central market, or part of a self-scheduling plan based on bilateral contracts or expected prices.
3. A **market operator** ranks the bids from lowest to highest price – this is known as the **merit order**.
4. The **highest accepted bid** needed to meet demand sets the **market clearing price**, which is paid to all accepted generators for that time interval.

Because prices are set by the most expensive technology needed to meet demand (typically diesel or coal in South Africa), even cheaper technologies like wind or solar earn this price – remembering this is happening in small windows of an hour or less, so matching price with the value of electricity in real-time. The difference between their low cost and the clearing price is their inframarginal rent, which helps them recover fixed costs like construction and maintenance. This mechanism is essential for attracting new investment in low-cost technologies.

However, this system depends on accurate demand forecasting. If demand is over- or underestimated, it raises system costs through responses needed to balance the system, and the resultant penalties on market participants. While this kind of supply-demand balancing will happen as a matter of course, it is helpful to keep it to a minimum through accurate demand forecasts.

Importantly, a system clearing price based on the marginal cost of the highest accepted bidder incentivises truthful bidding. Why? Because it is better to be selected and run at a price that covers these costs than not run, given that the initial investment has been made. Bidding too low risks losses, while bidding too high risks not being selected. This creates an efficient dispatch order and fair pricing. In addition, if bidders were only paid the price at which they bid (rather than the higher market clearing price), they are incentivised to "game the market", bidding ever higher to see at which point they are not selected, and then remaining just slightly below that. To maintain investment signals and protect consumers, policy-induced mechanisms may be added:

- Price floors can protect renewables from collapsing prices, as their marginal cost is almost zero, and this may result in a market clearing price of zero if renewables are able to meet all demand in a time interval.

- Price caps can protect consumers from extreme spikes. In such a case, all bidders are paid at the price cap, except for accepted bidders that have a higher marginal cost (to ensure they do not provide electricity below cost).
- Long-term contracts or bilateral PPAs supplement short-term markets to provide financial certainty and ensure cost recovery.

This balance of short-term efficiency and long-term stability is critical to building a functional, inclusive electricity market.

4.2 How price signals (rather than central planning) shape the energy mix

In a competitive market, investment risk lies with developers, not the state-owned monopoly (Eskom), as has been the case traditionally. When prices rise above a generator's marginal cost, it earns a short-term profit ("windfall"), attracting further investment in low-cost technologies. Over time, this competition drives system costs down and shifts the mix toward cheaper energy sources. Because the market sets the price dynamically through the day, the investment signals drive system flexibility.

Typically, the merit order is solar, hydro, wind, coal, nuclear, gas, diesel. Abundant solar power during the day drives prices down, sometimes even into negative territory, displacing more expensive producers. At peak times, the price is set by the last generators brought online to meet high demand. This is always the most expensive generation. In South Africa, peak is often met by diesel generation, but this would not be so in a well-designed system, where the high diesel price would likely drive innovation in battery storage, load management and even variable coal plant development.

The interesting impact of this is that as variable renewable energy penetration increases, the providers of constant inflexible power (coal and nuclear) will not be competitive at all times of the day. They fall into a grey zone between fully variable wind and solar and fully dispatchable hydro, gas and diesel. While some flexibility can be introduced via technology investment, they typically produce one amount throughout the day.

In theory, abundant cheap electricity in the middle of the day enables charging batteries and stimulates a more flexible industry that can thrive in cheap power. The peak-time prices reward flexible producers, incentivising innovation and investment. As more batteries are paired with renewables, they capture these high-value moments. And thus, the least efficient grey base-load supply options are phased out, *unless price signals enable sufficient investment in innovation to achieve greater flexibility*.

Renewable energy is starting to make measurable inroads into South Africa's daytime demand, with peak times needing gas and other dispatchable forms of electricity. These dispatchable sources are likely to be gradually displaced by storage (batteries). Meeting night-time demand, when solar is unavailable, wind is potentially unavailable and storage is depleted, still requires coal or nuclear in the near term. In South Africa, around 17 600 – 20 600 MW[11] of night-time

[11] Personal communications, Keith Bowen, NTCSA

demand remains. But as wind and storage expand, coal plants will run less, becoming costlier per unit and eventually uncompetitive.[12]

4.3 How might this unfold in South Africa: energy, carbon and justice implications?

As variable renewable energy (VRE) scales up, coal plants will operate less frequently, with utilisation rates declining over time; much like in China, where the average is already around 50% (Sustainability by Numbers, 2023). Despite this decline, coal plants are unlikely to be shut down entirely in the near term, as they provide important backup capacity in the event of variability in supply or broader system disruptions (as seen in Germany). This reserve role is often supported through capacity markets, which compensate plants for remaining available, even if rarely dispatched.

As coal plants run fewer hours, often limited to night-time or peak demand periods, their ability to recover costs declines. In some cases, they may even offer power at zero or negative prices to avoid shutdown costs.[13] With fixed costs spread over fewer operating hours, their cost per unit rises, creating space for alternatives like long-duration storage, demand-side management, energy efficiency, and regional power imports to enter the market competitively.

Initially, coal plants may remain competitive, especially if fully depreciated (paid off). But as carbon pricing intensifies and cleaner alternatives become cheaper, even these legacy plants will become unviable. The most expensive or least efficient coal units, often older or under costly contracts, are usually retired first.

VRE offers a lower-cost path and addresses the critical local and global pollution challenges posed by our coal dependence. Once VRE, storage, and flexible peaking options can meet new demand and begin replacing retiring fossil capacity, net emissions will start to decline in absolute terms. However, during the transition, emissions per capita may fall before total emissions do, reflecting population growth alongside ongoing fossil use.

Rapid renewable buildout may result in temporary oversupply. This could lead to price dips or surplus energy entering regional markets, potentially supporting transitions in neighbouring countries, if backed by international finance.

Ultimately, fossil fuel retirement will continue until very high VRE penetration is reached (typically around 75%), beyond which additional grid support tools become essential.

As investment shifts to renewables and grid infrastructure, with greater energy capacity and reliability established, South Africa can expect economic growth, with job creation in new energy systems and supporting industries offering some offset to job losses in coal power, and technology spillovers to new sectors.

[12] A night-time demand of 21GW indicates the short-term need of the 2GW nuclear plant and only 19GW of coal – much smaller than the current coal fleet of 48GW.

[13] There are costs related to shutting down and starting up a coal-fired power plant, including staffing costs (to manage shut-down/start-up), fuel costs to get the boiler up to operating temperature, and wear and tear costs related to expanding and contracting metal as the plant cools and warms.

5 South Africa’s reform journey

While South Africa indicated its intention to undergo market reform of the electricity sector as early as 1998, it has been a slow journey across a politically complex landscape. South Africa lags the 100-plus countries that have implemented various forms of electricity market liberalisation.

The reality is that South Africa recovers the costs of electricity provision through large bailouts of Eskom and of municipalities, with a large portion unrecovered; resulting in a vicious cycle of ballooning debt and underspending on maintenance, and little new investment. Global sector disruption provides increasingly affordable alternatives that can be installed at a variety of scales by those with access to capital, undermining the grid and social protection, as costs and subsidies are avoided. South Africa has had to grapple with the realities of being a small, open economy, with limited ability to set independent financial/monetary policy – we cannot “print money to get out of this situation”. With loadshedding costing the economy an estimated R224 billion between 2020 – 2023 (PARI, 2024), reform must be engaged.

Key milestones

- **1998**: The **White Paper on Energy Policy** first proposed transitioning to a competitive electricity market and unbundling Eskom. This is set within strong policy principles of access and affordability, economic efficiency and environmental care.
- **2008**: South Africa experiences its first wave of **loadshedding** due to capacity constraints.
- **2011**: The Integrated Resource Plan introduces renewable energy into the national mix, leading to the launch of the state auction/single buyer **REIPPPP** (Renewable Energy Independent Power Producer Procurement Programme).
- **2015-2019**: **REIPPPP** is **stalled**, because the Minister of Energy pursued nuclear, and Eskom’s CEO strongly opposed further renewables bid windows. This stall was damaging to local industry, resulting in the closure of at least one manufacturing plant (Morris et al., 2020).
- **2021**: **Schedule 2 of the Electricity Regulation Act** is amended to raise the licensing threshold for private generation from 1 MW to 100 MW (removed entirely in 2023), enabling large-scale private participation.
- **2022**: The **Energy Action Plan** is introduced to address the energy crisis, laying the groundwork for market transformation.
- **2023–2025**: The **Electricity Regulation Amendment Act** (ERAA) and the formal establishment of the National Transmission Company of South Africa (**NTCSA**) mark a structural pivot toward market liberalisation.
- **2022/2025**: The **SA Renewable Energy Master Plan**, developed in 2022 and approved by cabinet in March 2025, aims to leverage investment in the renewable energy value chain to deliver decent jobs and support economic growth.
- **2024**: A Market Code is drafted (not yet finalised), which provides the legal and technical framework as to how the market will operate.

REIPPPP has contributed some 6 GW (of 55 GW installed in the country) of installed capacity since 2011, substantially in wind and solar. This amounts to about 11% of the country's electricity capacity, but some 8% of the actual energy being produced in the third quarter of 2024 (IPP Office, 2024; Stats SA, 2024a). The 104 projects that have reached financial close by September 2024 attracted R239 billion investment and created 82,539 job-years: two-thirds of these in construction, with the remainder in operations (IPP Office, 2024).

The Schedule 2 amendment (2021) opened the doors to bilateral power purchase agreements (PPAs) between private producers and sellers, where private producers sell electricity to private consumers and "wheel" (transport) electricity across state-owned grids.[14] This effectively resulted in a de facto market operating outside of clear rules and regulations, or fair pricing practices. Current bilaterals do not pay the true value of their grid services or pay for any system instability they may cause. The development of a formalised, central wholesale market governed by a Market Code aims to provide fair access to the grid for all participants, establish a transparent platform for price discovery, enable efficient dispatch and balancing, and mitigate risks of market dominance.

Policy and institutional anchors for South Africa's reform efforts are:

- The **Electricity Regulation Amendment Act (2025)**[15] lays out the legislative basis for a competitive electricity market and the unbundling of Eskom into Eskom Generation, Eskom Transmission (which became the NTCSA) and Eskom Distribution. After 5 years, the NTCSA is to be legally unbundled (separated from Eskom Holdings), into a state-owned Transmission System Operator.
- The **Eskom Roadmap** outlines the restructuring of the utility into separate generation, transmission, and distribution entities.
- The **Energy Action Plan** focuses on restoring supply security and attracting investment.
- The **Just Transition Framework** is the cabinet approved guide to navigating the energy transition, ensuring equity and environmental goals remain central. The **Just Energy Transition Investment Plan** supports this transition through financing.

Together, these efforts reflect a growing consensus: the current system is unsustainable, and only a coordinated, inclusive reform process can secure energy access, affordability, and long-term viability.

[14] There was lack of clarity as to whether organs of state could undertake procurement from independent power producers. Whether a Ministerial Determination is required still remains an area of uncertainty.

[15] Recently promulgated, subject to the changing of the definition of reticulation, which limited municipalities' authority (to systems at or below 11kV) and was therefore challenged by the South African Local Government Association.

6 What wholesale electricity market structure is being proposed for South Africa?

6.1 Market design and function

Unlike the global process of liberalisation of the 1990s, South Africa is shifting to a more market-based design in an incremental way and embracing a pluralistic approach. This envisages participation by both the state and private sector. While short-term marginal pricing from day-ahead and intra-day bids will set the price in real-time, other mechanisms such as long-term bilateral power purchase agreements will contribute towards a degree of system stability.

South Africa's proposed market model is hybrid, with a central platform for bidding, dispatch of energy and capacity, and system operator oversight, whilst also allowing for bilateral (energy only) power purchase agreements (PPAs) between independent power producers (IPPs) and off-takers, outside of the market platform. They will however be balanced on the market, i.e. they must forecast their supply/off-take to the market platform and any differences between actual and forecast is charged (if it causes system imbalance) or paid (where any actions contribute to keeping the system in balance).

Eskom generators will continue to dominate generation in South Africa in the short- to medium-term, but as unbundled players, rather than a single entity. Initially, vesting contracts (risk mitigation mechanisms) will limit Eskom's exposure to market competition, as well as their ability to dominate the market, so ensuring price stability.

It is also important to have competition amongst buyers in the market, improving the 'price discovery' and driving efficiency through greater market liquidity. In line with most liberalisation processes, the draft Market Code limits 'eligible market participants' (those allowed to buy directly from the market) to customers connected at the medium voltage level or above. Direct participation is onerous: markets are complex, and participation requires specialised skills and financial guarantees. The metering and administrative burden to deliver to smaller (low voltage) buyers would be too onerous in the early stages of market implementation.[16] It is anticipated that initially there will likely be about 10 buyers, comprised of large industries (e.g. Sasol), traders, Eskom Distribution and a couple of the larger metros or municipal distributors. Traders participating in the market have a role to play providing liquidity (matching buyers to sellers) and hedging (financial contracts to insure other market participants against risk).

Most small customers (residential and small business) will remain 'captive' (i.e. unable to choose who they buy electricity from) and subject to regulated prices. However, the role of traders complicates matters: they can handle the complexities of the market on behalf of customers, enabling greater volumes of 'load' to be represented on the market. This has

[16] It is worth noting that although NERSA's Regulatory Rules on Network Charges for Third-Party Wheeling of Energy (March 2025) allow wheeling at all voltage levels, distribution utilities will similarly need to restrict low voltage participation due to the metering and administrative burden. Work is underway to establish regulated export credit tariffs for small-scale embedded generation, and 'net export' is under consideration, although this raises complex procurement and tax issues.

implications for the distribution sector. While the use of system (network) costs will still be paid by all parties, these need to be accurately costed (including the regulated return on investment) and include any subsidy elements that may currently be held in the current energy charges. Allowing retail competition before network services are accurately costed and priced, will result in under-recovery for these services by distribution utilities.

Key features of the proposed South African market model:

- **Day-ahead market and intra-day markets for both energy and reserve energy**
    - Generators and buyers submit bids one day in advance.
    - In the intra-day market, bid adjustments (for volume of energy, not price) can be made closer to real time, e.g. every 6 hours, every hour, or even every few minutes.
    - The NTCSA matches supply and demand and sets a market-clearing price.
- **Balancing mechanism**
    - Real-time adjustments to manage deviations from day-ahead commitments (or intra-day adjustments).
    - Essential for integrating variable renewables.
- **Vesting contracts and legacy management**
    - Generation assets built under the legacy system need to be carefully integrated into the market to ensure competition but also avoid stranded assets.
    - Eskom's generation fleet will be gradually exposed to competition.
    - Transitional contracts (vesting) will provide price stability and predictability.
- **Ancillary services market**
    - Procurement of essential grid services (e.g. frequency regulation, spinning reserve, reactive power, etc.) from qualified providers.
- **Traders and aggregators**
    - Facilitate participation for municipalities, small-scale generators, and customers.
    - Offer services like portfolio management, hedging and billing.

6.2 Roles and responsibilities

Oversight and policy roles:

- **Department of Electricity and Energy**: Provides policy oversight and system planning. The ERAA does allow the Minister to go outside of the market to procure energy, should there be capacity shortages, or to effect policy goals.
- **NERSA**: Regulates tariffs, approves market rules, and monitors competition. NERSA will be the ultimate custodian of the Market Code, now under development by the NTCSA. NERSA will be responsible for appointing and funding a Market Code Advisory Committee and for the ongoing modification and development process – similar to the Grid Code development processes.

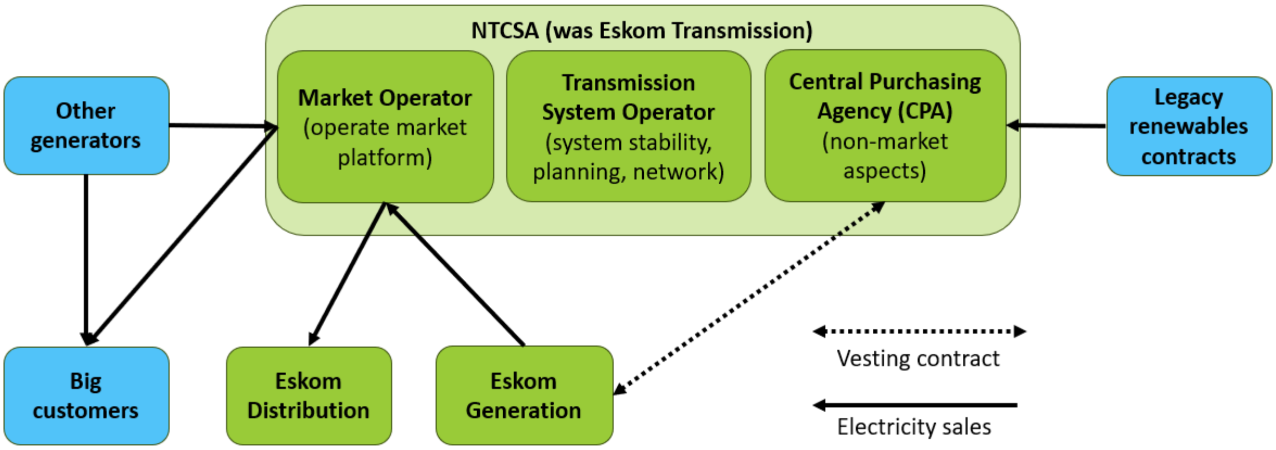


Figure 4. Market operation roles

Market operation roles (Figure 4):

- **NTCSA**: This entity has multiple roles:
  - **Market Operator**: Operates the market platform.
  - **Transmission System Operator**: Operates the system and balances the grid – ensures stability.
  - **Central Purchasing Agency** (CPA): A special purpose entity that deals with all non-market aspects. It will buy electricity from legacy renewables contracts from REIPPPP, manage the vesting contracts with Eskom, and – via Eskom Distribution – manage the purchase of electricity for local municipalities.
- **Generators** bidding into the market, which will include Eskom Generation and independent power producers.
- **Buyers** from the market, which will include Eskom Distribution, large consumers, traders and – in some cases – local municipalities (how they interact with the market will be covered in a later section).

The success of the market model requires complementary reforms. This includes tariff restructuring to reflect system costs, and subsidy mechanisms to ensure that tariffs remain affordable for low-income households. Municipalities must be enabled to participate in the market – current financial regulations, in particular the Municipal Financial Management Act (MFMA), inhibit this. In addition, grid investment and fair access to the grid is needed.

Challenges to watch out for include ensuring that legacy debts and inefficiencies are not simply passed through market prices, and that the transition is managed in such a way that the distribution sector is able to operate in a more dynamic, less predictable environment.

Electricity market reform is not just about wholesale pricing. It is about enabling a sustainable, inclusive energy system. Consumers – residential, commercial, and municipal – must remain at the centre of this transformation and be empowered (through smart tech and related opportunities) and protected.

6.3 Networks as the backbone of system operation

The ERAA is extremely clear that transmission and distribution networks will remain state-owned, and neither advocates nor paves the way for a privatised Transmission System Operator. However, **separating transmission from Eskom is key to removing the inherent conflict of interest, since non-discriminatory access to public networks is a cornerstone of market success.**

Network capacity expansion is required to support new generation sources. The integration of variable renewable energy necessitates grid flexibility and balancing mechanisms. This includes investments in energy storage, flexible generation, and demand response systems. Additionally, new transmission lines are needed to connect renewable energy zones to load centres. The transmission grid is well maintained, but estimated investment required for network expansion is R440 billion over the next 10 years (DBSA, 2025).[17]

Challenges with Eskom's balance sheet requires private investment for the rapid network build-out. National Treasury has developed a mechanism to enable private finance into the space through a build, operate, transfer model.

Distribution wires operation into the future requires investment in the traditional infrastructure (meters, transformers, etc.), and new bi-directional energy flow and flexibility technologies. This is hugely challenging, as Distribution Network Operators (managing the network) are now moving to become Distribution System Operators (managing their system's stability). This requires investment in assets with long-term investment horizons, and plans needed to future-proof the networks. How the South African distribution sector, notably municipal utilities, will adapt to these new and complex requirements across a multi-faceted and very context-specific distribution sector requires attention.

[17] A large share of capacity that bid into the latest REIPPPP bid window was not able to be built, due to network constraints.

7 Addressing market risks and concerns

The introduction of a market highlights significant risks and challenges. Frequently expressed concerns have been addressed where possible in the market design, but will require complementary reforms and vigilance from stakeholders.

Does a market represent the privatisation of key economic assets?
The market is designed to bring Eskom's extensive experience into the future ESI. Eskom generation will continue to own its plants, and the transmission and distribution networks will remain public assets. As old, fossil-fuel power stations are phased out, new capacity will be funded by private capital, as well as Eskom Generation. Experience in Latin America and India indicate a strong persistence of the state as an actor, often representing in the region of 50% of the market (Ahlfeldt et al., 2025). This will represent billions of rands of new investment and contribute to improved economic performance – and associated growth in jobs.

Will electricity become unaffordable?
Global experience indicates that wholesale markets are very effective at reducing overall system costs and improving efficiency, which puts a downward pressure on the tariffs and prices consumers pay relative to monopolistic power systems (Ahlfeldt et al., 2025). However, other variables also influence the final bill for customers, such as existing cross-subsidies and fluctuating fuel prices, as well as the degree of liberalisation[18], so there is not an easy yes/no answer to this question.

In theory, competition will minimise sector price escalation by enabling more efficient investment. Vesting contracts, which ensure a return on investment for Eskom Generation during the transition phase, will slow this down, but long-term costs are expected to be lower than they would have been without a market. *To ensure the benefits of competition are achieved and passed on to customers, the NTCSA must be completely separated from Eskom, as an independent transmission system operator.*

Subsidies for low-income users will be set through policy and be held "outside" the market, but charged to all customers in the system. These must be well-managed and targeted. Yet, there is a limit to which the South African state can ensure an entirely developmentally appropriate price level through subsidy.

Will there be price volatility and high price spikes?
Ordinary customers will not be exposed directly to price volatility; only large customers who become market participants. Most customers will remain 'captive customers', receiving electricity at regulated tariffs. Price volatility is expected and must be mitigated. Risks include "gaming" by dominant players (such as Eskom), grid constraints, and inaccurate demand forecasts. Retailers may be encouraged to hedge (mitigate risk) through available market mechanisms, such as long-term pricing agreements. Capacity remuneration mechanisms can avoid price spikes, by spreading volatile cost into fixed monthly payments.

[18] In India, long-term PPA prices have been significantly higher than market prices, with almost half of the coal projects costing 40% more on average compared to the spot price (Ahlfeldt et al., 2025).

The Central Purchasing Agency (CPA) will have a large role with regards to price stability and limiting market dominance. It will mitigate these risks through vesting (risk mitigation) contracts with Eskom Generation plants and with Eskom Distribution – the proposed entity that will buy electricity on behalf of municipalities. This means that any non-payment by municipalities will filter up through Eskom Distribution to the CPA. It holds the very real risk of collapsing the market, since the market cannot operate on debt (all money must be provided up-front). Local government financial reform is therefore critical. However, there is real structural debt in the system that must be addressed and a mechanism to cater for this. The Chilean Equalisation Fund offers a glimpse into a national mechanism that raises funds through a progressive surcharge on consumption (with exemptions for poor households and small enterprises) to ensure payments to generators and distributors whilst deferring price increases for regulated "captured" customers (Ahlfeldt et al., 2025).

There is a trade-off to risk mitigation: taming price volatility can dull the price signals that drive efficient investment. The system must reduce inefficiency (e.g. inaccurate demand forecast) through an emphasis on the capacitation of all players.

What if the market does not deliver the capacity we need?
Government may step in to obtain capacity where the market is not delivering what is required. Further clarification is required in the regulatory rules as to the basis on which the regulator, normally in consultation with the Minister, may step in. This requires attention, as the provision also runs the opposite risk that the capacity procured is not dispatched by the market (for example, nuclear or high-utilisation gas[19], which both do not work well to flexibly respond to renewables). Any energy or capacity that is not purchased by the market, due to its high costs, can be forced through via the CPA (a non-market mechanism) as a "legacy cost", which will then filter down to all buyers.

Brazil's wholesale market initially did not attract enough participants. This constraint was addressed by establishing an auction process with their private distribution companies, to unlock investment. Distributors were obliged to buy 100% of forecasted load in central auctions. These long-term contracts provided sufficient certainty to attract investment. Laws also exist requiring distribution companies to purchase a minimum percentage of renewable energy that increases over time (Ahlfeldt et al., 2025).

Does South Africa have the skills and capacity to manage such a complex system?
While the system's complexity raises concerns, core market operation skills (e.g. dispatch and balancing) are already well-established within Eskom Transmission – now the NTCSA.

Grid stability will be enhanced in a market through mandatory reporting requirements related to production and consumption held in contracts outside of the market – to increase visibility of the supply-demand balance by the system operator.

Distributors will be required to take balance responsibility for their demand, i.e. pay the cost of imbalances they drive. This means they must be able to forecast – and notify the system operator – of hourly changes in the amount of electricity they will need to buy. Most local

[19] Low-utilisation gas is a better match to variable renewables.

municipalities are unlikely to be able to do this, which is a real concern. Initially, this role is likely to sit with Eskom Distribution, who is the proposed entity that will buy electricity on behalf of local municipalities.

NERSA must be empowered to set and enforce rules in a complex political environment. This includes ensuring there is no collusion or gaming by the large incumbent, Eskom, or the private sector. It also includes ensuring that the real cost of electricity is recovered through the regulated tariff, without which the system will fail. The regulator's capacity is of critical concern, given the complexity of the task and the rapid response required to course-correct when things go wrong. Delayed action in a market setting can have severe repercussions.

Governance issues and the skills and capacity of municipal distribution to participate in the system requires attention. Municipal capacity concerns are detailed in section 8: "How will municipal distribution utilities participate in the market?"

Will private sector profiteering increase prices?
An asset-centric business, such as the electricity sector, will always include a fair return on investment – whether state or privately owned. This is to enable ongoing system investment, ensure access to capital, and buffer against risks such as demand fluctuations or regulatory uncertainty. While marginal cost pricing of competitive wholesale markets appears to enable 'windfall profits', this must be understood in the context of the pricing mechanism: marginal costing puts forward the price of rendering an additional unit – predominantly operational costs – and 'windfall' supports the capital investment. The signal offered by the price should attract competition into inefficient areas, bringing prices down.

It is generally accepted (though not without debate) that the efficiency gains of private sector involvement push costs down and outweigh the risks. Furthermore, the public sector simply cannot make the investment required – they cannot afford it. A market with well-designed pricing signals therefore encourages private sector investment, enhances competition and keeps cost increases to a minimum. This should drive economic growth, tax revenue and innovation. Strong regulation and transparency are essential to ensure fair outcomes and prevent profiteering – whether public or private.

Will renewables still attract investment if daytime prices fall to zero or below?
The market is designed to send signals that support ongoing investment. Tools like minimum price floors, contracts for difference (which specifies an agreed set price) and planning interventions may be considered to ensure long-term policy goals – like renewable deployment – are met, even when short-term prices fall.

Net-Billing Rules for Embedded Generators (NERSA, 2024) enable export tariffs at the distribution utility. This allows residential consumers and small generators to sell surplus energy to the grid at regulated prices – although many municipalities do not yet have this functionally in place.

Will municipal revenue collapse?
Municipalities will continue to earn regulated returns on their distribution network assets (wires) through use-of-system charges. Financial sustainability depends on accurate

accounting of municipal services within the utility business, sound asset registers, proper depreciation methods, and proper separation of the network costs from retail costs. Those with the necessary capacity may continue to operate a retail business (on-selling of electricity).

Will the poor be left behind?
Inclusion and justice require that costs are kept as low as possible and that the poor are subsidised where they cannot afford full costs. Competition through the market will provide the cheapest electricity. This must be complemented by effective system management.

Affordability gaps must be identified and addressed through targeted subsidies "outside" the market, set through policy[20] and delivered through fixed charges or other suitable mechanisms that ensure these charges cannot be avoided. These mechanisms are critical to ensure equitable access and prevent exclusion – or 'grid defection' (of low-income customers) to criminal enterprises. This issue is dealt with in detail in section 10: "Outlook for pricing and policy implications".

In conclusion, the argument that wholesale electricity markets are "financialising" the electricity sector is a critique rooted in concerns that the design and operation of competitive electricity markets increasingly reflect the logic of financial markets – with prices decoupled from production costs and social needs – rather than the original goals of delivering reliable, affordable and equitable electricity as a public service.

Well-designed markets can integrate long-term (cost-based) contracts and social policy goals if properly regulated and with sufficient public oversight. Markets globally have critically unlocked renewable energy capacity and decarbonisation. Private investment in South Africa has already disrupted the system – energy efficiency saw flattening demand curves in major metros from 2008 and embedded generation and private wheeling has already contributed ~6 GW of installed solar capacity (Eskom weekly updates, June 2025). This has been positive for capacity and driving renewable energy development, but without reform is causing inequities and inefficiencies due to incorrect pricing mechanisms. A wholesale market is able to manage this evolving space of multiple generators and off-takers.

[20] In other words, this should not be addressed in the Market Code, which simply states the "rules of the game" for participating in the electricity market.

8 How will municipal distribution utilities participate in the market?

8.1 The distribution utility landscape

At 42% of market sales (representing 60% of the customer base), municipal distribution utilities are significant buyers of wholesale electricity in South Africa. The remaining 58% is distributed by the state-owned entity, Eskom. The participation of municipal distributors in the market will underpin successful market reform.

Municipal utilities are regulated through their license conditions. They are also governed by legal frameworks pertaining to local government: Schedule 4B of the Constitution lists electricity and gas reticulation as a local government responsibility. This includes ensuring the provision of this service in a sustainable manner, as well as in a manner that promotes economic and social development (SA, 2000). Municipalities are the recipients of government grant funding from National Treasury for both electricity infrastructure and services.

Of the 177 municipalities in the country, 167 are licensed distributors. The 20 largest municipalities sell 86% of electricity; the smallest 80 municipalities account for only 2% of sales. The scale and difference in structure across the industry make governance (establishing of rules and regulations) extremely difficult. The industry structure is set to undergo a reform process. This is needed to address governance issues and sector debt crisis, service delivery and performance improvement, as well as future distribution system operation requirements in a wholesale market. Key challenges include:

- Infrastructure neglect, manifesting in aging networks and poor asset management.
- Financial stress arising from revenue collection issues and poor tariff structures.
- Institutional fragmentation, with over 160 licensed municipal distributors with varying capabilities and insufficient regulatory oversight.

Municipal entities were historically structured around passive electricity resale. Over the past decade, municipalities have navigated 'embedded generation readiness': getting policy and regulation in place for bi-directional energy flow, understanding grid impact and connection requirements, and establishing fair prices. As the sector shifts toward a competitive market, municipalities must engage an even more complex environment.

8.2 What are the pathways to market participation for distribution utilities?

Potential options for market participation include the following tiers:

- **Direct participation** in the market for stronger, well-resourced metros and municipalities. They will get a vesting (risk mitigation) contract from the CPA for the transition period, to manage risk.
- **Indirect participation** via licensed traders (could even be a larger metro), who aggregates and manages procurement for smaller municipalities unable to develop all the requisite skills, but with sufficient liquidity to be engaged in market transactions.

- It is anticipated that most municipalities, especially the smaller ones, will remain customers of a "supplier of last resort" (such as Eskom Distribution), **buying at a regulated price** – as currently happens.

Distributors will on-sell electricity (bought from the wholesale market, a trader or supplier of last resort) at a regulated retail price to all 'captive customers' – those who are not buying directly from the market. With EDI reform processes underway, municipalities may opt in the future to outsource elements of their retail functions or amalgamate service delivery with other entities.

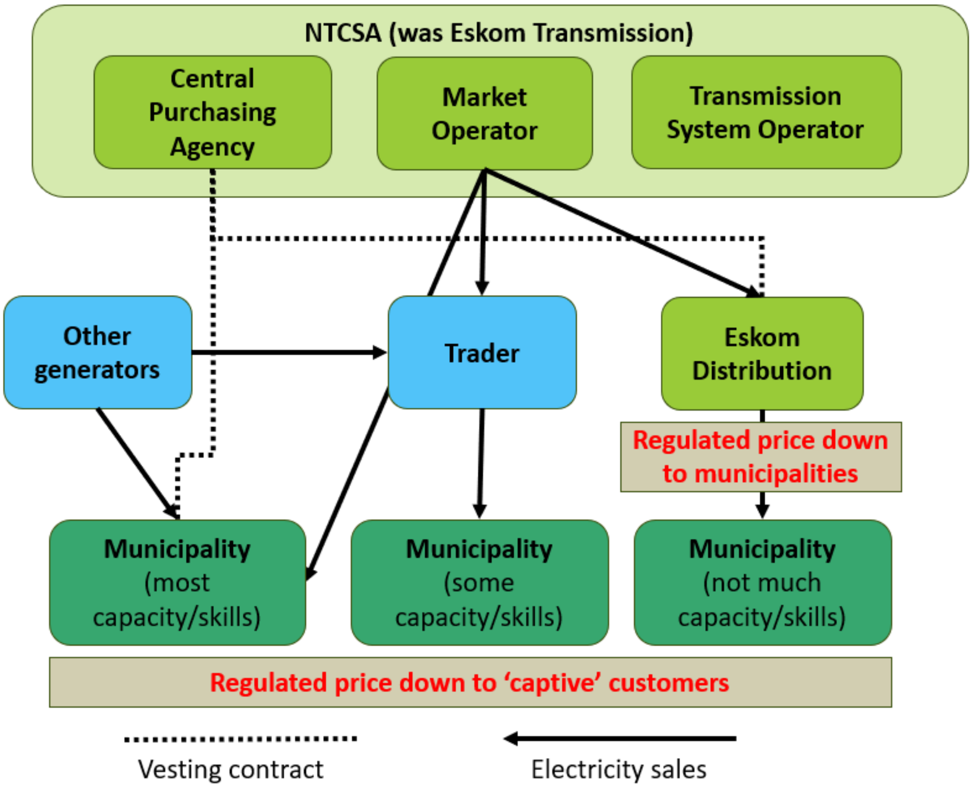


Figure 5. Municipal distribution participation options[21]

8.3 What does this mean for customers?

Under the proposed Market Code, only very large customers may participate directly in the market. Currently these customers sit within the Eskom transmission (high voltage) networks, buying wholesale from Eskom. These customers could participate by building their own supply portfolio, taking on balancing responsibility for mismatches between contracted supply and actual demand, or by using a trader to manage this risk, with the trader aggregating loads and handling balancing.

There is lack of regulatory clarity and some concern that traders operating in the market may sell directly to off-takers at the medium voltage level within distribution/retail markets. This will effectively remove a fair portion of the retail business out of the current distribution sector, prior to retail market design being in place. There is no explicit regulatory framework that guides

[21] Note that the "supplier of last resort" is still not resolved. This graphic shows it as Eskom Distribution, as proposed in the first draft of the Market Code.

commercial terms, use-of-system charges, or supplier-of-last-resort protections for such a case.

Distribution customers will remain "captive customers" – paying regulated tariffs approved by NERSA. These tariffs are based on cost-of-supply studies, to ensure fairness and transparency. In this model, market volatility is buffered through the CPA, though the details of how this is funded and implemented still need to be finalised.

Larger customers connected at the medium voltage level within distribution grids may source power from independent power producers through power purchase agreements. This power would be 'wheeled' to customers through amended supply agreements with distribution utilities. The market will ensure that parties to these bilateral agreements become 'balance responsible', i.e. pay the cost of any imbalance they may cause.

8.4 What are the challenges for municipal participation?

There are questions that still require resolution in relation to the distribution sector in the wholesale market, notably:

- **Supplier of last resort**: This refers to an entity designated to ensure continuous supply to consumers in cases where their current supplier fails, crucial for protecting consumers from sudden service disruptions. Eskom currently serves as the de facto supplier of last resort in South Africa. This means that Eskom absorbs the non-payment of retail bulk purchases by municipalities.

  ERAA gives the Transmission System Operator (TSO) the role of a central purchasing agency (CPA), which deals with non-market aspects, such as shouldering the risk of the electricity supplier designated to on-sell to municipalities that are unable to purchase from the market. However, operational mechanisms for this "supplier of last resort" role are not yet defined. This supplier (proposed as Eskom Distribution initially) will have a vesting contract with the CPA, hedging against municipal non-payment. However, if systemic non-payment is not addressed, the CPA will require bailouts.

- **Non-payment risks**: Weak municipal distributors may default, passing financial risk upstream – from Eskom Distribution or a trader to the market operator. Without safeguards, this could destabilise the market, as seen in India and Mexico (Geddes et al., 2020).

  While the supplier of last resort may act to mitigate these risks, continuous bailouts will undermine the market. It is critical that a full understanding of both the governance issues and funding issues related to municipal non-payment are well understood so that due market preparation can be done by the sector and indeed, the state more broadly. Effective subsidy design and delivery are critical to protect the most vulnerable customers and prevent systemic risk.

- **Forecasting demand**: Accurate demand forecasting is critical for system efficiency, since imbalances as a result of incorrect forecasts will push up system costs (higher levels of reserve capacity will be required) and will be penalised. Forecasting at the distribution level is complex, and few municipalities have the tools or skills to do this well. A trader, or Eskom Distribution, will likely perform this function on a municipality's behalf.

- **Regulatory gaps**: NERSA and distribution utilities must ensure the correct level and structure of tariffs are set and develop fair methods for allocating losses. This is a highly political terrain and must be actively supported by political leadership across government. NERSA must also address the mismatch between volatile market prices and regulated retail tariffs, which risks over- or under-recovery. This requires forecasting skills.

9 Municipal distribution: recovery and reform

While the electricity sector problem of ballooning debt, and underinvestment in maintenance and new infrastructure, is acute across generation, transmission and distribution, it is most worrying in its interaction with local government. This aspect of electricity provision is least understood and embedded in fundamental weaknesses of municipal business models and the changing dynamics of consumer demand. As municipal electricity distributors are essential to the future electricity market, as well as the servicing of captive customers, addressing these challenges must be prioritised.

9.1 Recovery alongside reform

Most municipal distributors are struggling to meet their mandate: providing basic services, ensuring financial sustainability, and supporting equitable development in a post-Apartheid context. Their ability to participate in the wholesale market depends on urgent recovery and reform – across governance, financial management, infrastructure, technology and institutional capacity.

Reform of the electricity distribution industry (EDI) must begin with stabilisation: tariff restructuring to reflect real costs, debt management, investment planning and governance reforms. Mechanisms to deal with municipal arrears to Eskom, alongside improving payment in municipalities, improved subsidy targeting, professionalising leadership and improving accountability all need to be national priorities. Upgrades to support grid reliability and grid integration of embedded generation need to be coordinated and well-planned, and asset-related costs accurately represented in tariffs. This work has been well-framed in the National Treasury City Support Programme's Metro Trading Services programme.

Whilst this effort needs to be a *national* focus, there needs to be greater *in situ* contextualising of the challenges – or solutions will be inadequate. Evidence indicates a complex interaction between structural and governance challenges, and it is not scale or location that is the determinant of better or worse utility outcomes (CPCS, 2023). EDI reform work must locate itself in this complexity: new organisational structures, and amalgamated utility functions may address some issues, but is not a panacea if underlying structural and governance matters are not addressed. Expenditure concerns pushing price up across the sector include:

- **Distribution losses** due to technical issues, resulting from aging infrastructure, and non-technical losses, which covers theft (illegal connections or non-payment) and billing errors. The state itself, and larger customers, contribute significantly to this feature. The 'squeezing' out of free basic electricity (FBE) allocation has also played a role.
- **Sales reduction and changing demand load profiles**. While sales have reduced, maximum demand has reached an all-time high due to cold load pickup demand spikes when electricity is restored after loadshedding. This has led to a reduction in the load factor, which makes it very difficult to recover the cost of network assets, which are sized for maximum demand but amortised across energy sales. This also erodes the cross-subsidy for subsidised tariffs (e.g. municipal "Lifeline" tariff).
- **Municipalities' debt to Eskom**. This has escalated from R45 billion in the 2021/22 financial year, to over R90 billion in the 2024/25 financial year.

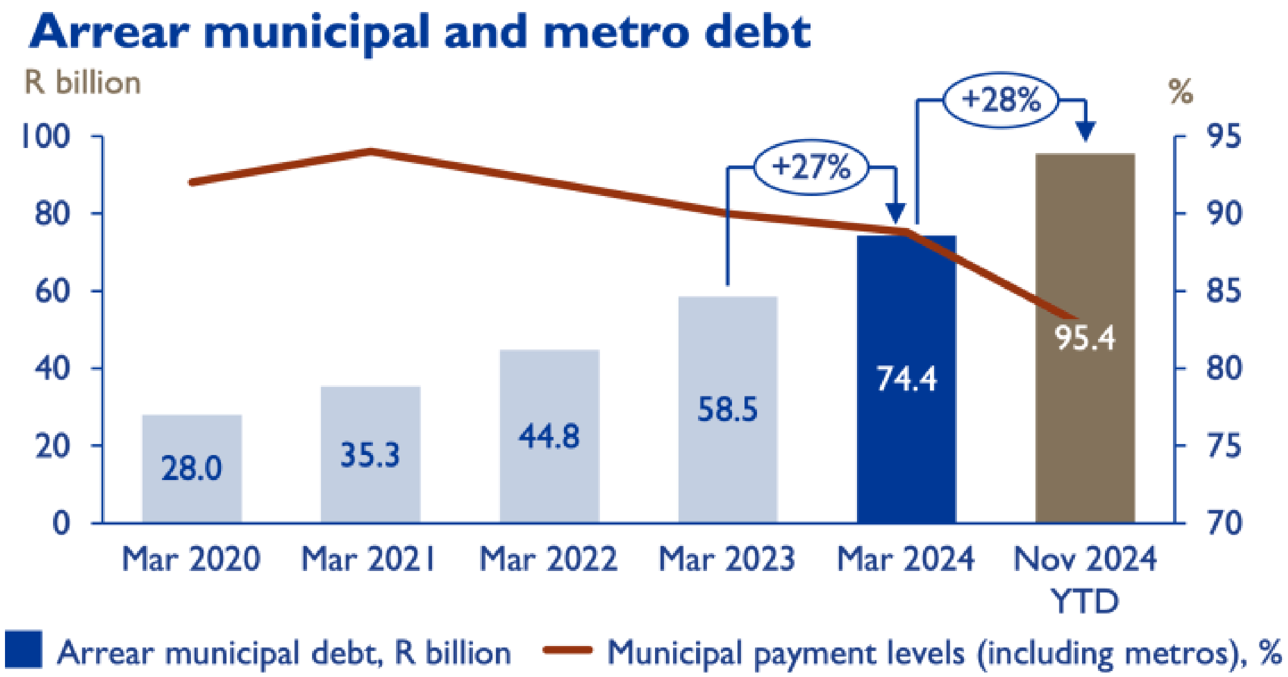


Figure 6. Municipalities' debt to Eskom. Source: *Eskom*

Many municipalities under-account for depreciation and fail to generate sufficient operating surpluses, resulting in chronic underinvestment in maintenance and upgrades – and consequent unplanned maintenance and system failure. The Integrated National Electrification Programme (INEP) grant, or the Urban Settlements Development Grant (USDG) for metros, does not include funding of upstream grid costs, and a lack of ringfencing of development charges more broadly means that money for refurbishment is under-recovered or not reinvested in the network.

Repairs and maintenance, including breakdown response and planned maintenance, is required, but falls away in the absence of skills, control rooms, diagrams and strategies, and as networks age, more and more reactive maintenance takes place as breakdowns become more frequent.

A sustainable surplus – revenue above operating costs – is vital for system refurbishment and modernisation, but few municipalities are generating this.

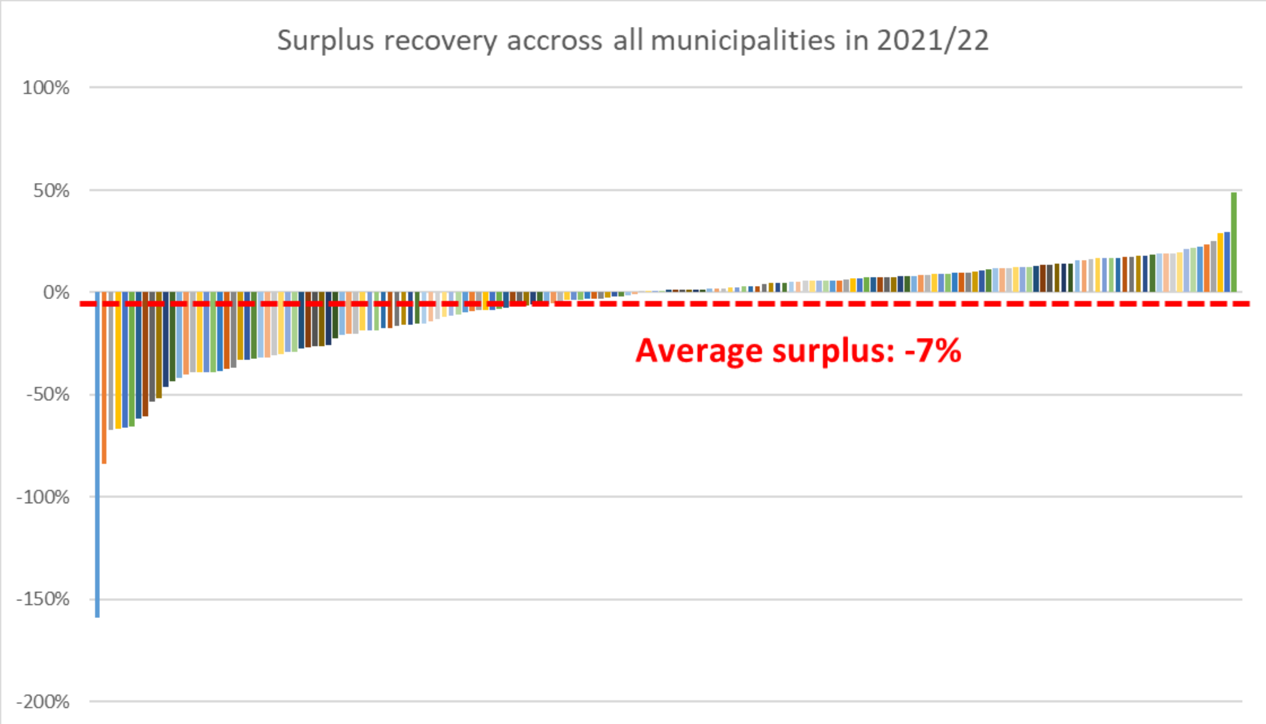


Figure 7. Surplus recovery across all municipalities in 2021/22. Source: Barnard, 2025b.

The issue of under-recovery and 'borrowing from infrastructure' by deferring investment and undercharging for service, is widely known in the industry. Whilst cost of supply studies will help guide fair tariff design, the price increases and structural changes needed to achieve cost-reflectivity are often politically unpalatable and rejected by leadership. Resolving this requires national-level planning and support, and strong political will.

9.2 What are the roles of a municipality in electricity into the future?

Municipalities must proactively define and prepare for their future roles in a transformed electricity sector. Integrating distributed energy resources, such as VRE and battery energy storage systems, places far greater emphasis on flexible capacity, which takes place in the distribution networks and system operation.

New roles in a decentralised, dynamic electricity system require dedicated, long-term capacity-building, and the development or re-orientation of institutions to undertake new functions (structural reform). This may require consolidation of smaller distributors into stronger (regional) entities. Greater standardisation – common technical, financial and customer service standards – will need to be supported to achieve improved service delivery.

Core business requirements are changing and a clear demarcation between the different activities is needed (Figure 8). With new structural opportunities opened through the EDI reform process, municipalities may selectively focus on functions, depending on capacity and strategy. Outsourcing of functions through service delivery agreements enables continued public ownership.

Regulated monopoly (municipality likely to retain)		Market (municipality may hand this over)	
Distribution System Operator	**Network Service Provider**	**Retailer**	**Trader**
Functions • Stability (voltage, frequency) • Market enablement systems • Communicating constraints with TSO	**Functions** • Network maintenance, operations, planning • Metering • Tech. losses management • Use of system tariffs	**Functions** • Buy wholesale electricity • Sell electricity to customers • Customer services & tariffs • New connections • Non-tech losses management • Balance-responsible party	**Functions** • Aggregator, e.g. virtual power plant • Trader, e.g. of portfolio

Figure 8. Municipal electricity roles into the future. Source: Van der Merwe, 2025b

The **network and system business**, responsible for system stability and the operation and maintenance of the network, will remain fully regulated and can provide municipal electricity distributors with predictable returns based on cost-of-service considerations, provided that the network performs effectively, efficiently, and reliably[22], and the asset-base is well accounted for.

For the distribution networks to accommodate distributed energy resources, such as embedded generation, and to thrive as network service providers for wheeling, substantial capital investment in the networks, and associated technology, will be necessary. The new capacities required will include network studies for distributed energy resources integration, stability/frequency analysis, and local municipal grid analysis to address capacity constraints and congestion.

Strategic investment in refurbishment and maintenance at a municipal distribution level is critical to ensuring grid reliability. In addition, grid modernisation must be done to enhance distributed energy resources integration and energy storage. Networks must be able to accommodate bi-directional power flows and integrate smart grid technologies such as advanced metering infrastructure, demand response systems/load management or aggregation, and automation. Automation and digitisation improve grid efficiency and reliability by enabling predictive maintenance and fault detection.

The **retail and trade business**, responsible for the procurement of energy for subsequent resale to end users, will require a separate and distinct trading license. The procurement function may be included as part of the retail business or may be shifted into a separate trader function, depending on the organisational strategy and design.

However, the resale of wholesale electricity to residential customers is likely to be a wholly regulated component of the business for many years to come. Energy balancing responsibility will require new commercial contractual arrangements like trading, clearing and settlement of purchasing requirements. Advanced metering infrastructure is required for pricing of new

[22] Distribution System Operating Code, Version 6.1 defines responsibilities around economic, reliability and security requirements; contingency planning; power quality; operation under normal and abnormal conditions; outages and safety requirements. The code serves as a baseline of the distribution system operations skills requirements for licensees, across all activities defined in the electricity distribution value chain. It is important to unpack the additional or enhanced functional requirements in a reformed market.

services, such as flexibility. Demand response systems allow consumers to adjust their usage based on price signals, enhancing grid flexibility.

Trading in longer-term markets needs to be increasingly complemented by trades in the day-ahead and intra-day market. As distributed energy resource volumes grow, flexibility will become a valuable service. These shifts place increasing pressure on the trading function to ensure the securing of the correct, least-cost, generation option mix and interventions that improve grid flexibility, enabling distributors to 'sell' this to the grid, shaving peak costs and earning return on these investments.

Municipalities represent substantial load and have an important role to play in anchoring new energy investments. Transaction costs are steep, however and this will need to be addressed either through consolidation of this function into bigger entities (but with the municipalities as owners), through potential support from an IPP office that can consolidate transaction costs (and mitigate the risk), or other institutional evolution.

10 Social equity and pricing: addressing the affordability-revenue gap

South Africa's electricity system must meet two goals that often appear in tension: recovering the full cost of service while ensuring that electricity remains affordable for low-income households. Addressing this affordability-revenue gap ('structural debt') in electricity is critical for a just transition and for municipal sustainability, since the distribution industry (Eskom distribution and municipalities) sits at the coalface of electricity service delivery and revenue collection.

Access to modern, affordable and clean energy is embedded in South Africa's constitutional commitments to redistribution and development. The national policy framework, including the Constitution and Electricity Pricing Policy (EPP), supports access through subsidies and progressive tariffs. South Africa has a globally recognised policy framework for social equity regarding electricity services provision: the Constitution, the Electricity Pricing Policy (EPP), the Municipal Systems Act (Act 32 of 2000) and the Municipal Services Act (Act 13 of 2001):

Access to modern, affordable and clean energy is critical for socio-economic wellbeing[23] and is embedded in South Africa's constitutional commitments to redistribution and development. South Africa has a globally recognised policy framework for social equity regarding electricity services provision: the Constitution, the **Electricity Pricing Policy (EPP)**, the Municipal Systems Act (Act 32 of 2000) and the Municipal Services Act (Act 13 of 2001). This supports access through subsidies and progressive tariffs, including:

- **Capital subsidy for connections**: The Integrated National Electrification Programme grant (or USDG in metros) funds household connections. Blanket electrification drives ensure all households are part of this, and costs are reduced through economies of scale.
- **Basic service subsidy**: The Local Government Equitable Share grant supports free basic electricity (FBE), targeting 50 kWh/month for qualifying indigent households.
- **Subsidised tariffs**: Lifeline tariffs ensure affordability through low rates (and no fixed charges) for low-consumption users (defined as a customer with a 20 Amp connection), subsidised by cross-subsidies within the tariff structure – in line with EPP direction.

10.1 Establishing the 'affordability-revenue' gap

Free Basic Electricity (FBE) and Lifeline tariffs represent a substantial and important transfer of wealth, as envisaged in our national Constitution. The Local Government Equitable Share grant provides ~R15 billion to support FBE services, but this is not finding its way to electricity revenue and a funding 'gap' of approximately ~R30 billion per annum persists from the below-

[23] Recent research (Sishi, 2024) indicates that free basic electricity (FBE) recipients consume 52.4 kWh more (almost exactly the FBE provision) and spend R78.25 less per month on energy than non-recipients. Households receiving FBE are also 8.9% less likely to use alternative fuels, report better health outcomes (+0.183 on a 5-point scale), show improved education indicators (3.7 percentage points increase in school attendance and 0.752 hours increase per week in evening study time), and are more likely to be employed or operate home businesses. This demonstrates the socio-economic impact of FBE, in enabling economic mobility and social development.

cost 'Lifeline' or 'Homelight' (Eskom) tariffs. This shortfall has been partly met by cross-subsidy, but provides a worrying structural debt within the system that if unaddressed will deepen.

It is critical that the quantum is well understood, and initial attempts to do this are outlined below. The precise quantum is difficult to determine, as there are multiple moving parts across ~167 licensed distributors (including Eskom Distribution):

Establishing the true cost to provide the service:

- This is established in cost of supply studies, which are emergent in the county.
- Costs do converge, but differ according to local context (number and mix of customers, terrain, etc.).
- In practice, across distributors, the subsidy target group is not necessarily homogenous. A Lifeline tariff ('Homelight' in Eskom distribution areas) may be determined by technical connection level (e.g. only 20 Amp connected customers), or by location, which may include a range of connection levels and driving different costs.

Establishing the revenue recovered to meet the affordability gap:

- The amount of FBE provided per customer is set by each municipality's Council policy, though nationally the EPP does give direction as to the volume. In practice, the amount of FBE provision ranges from 50kWh to 200kWh per month, and beneficiary targeting approaches differ – resulting in differing Local Government Equitable Share allocations to electricity.
- Inclining block tariffs make it difficult to estimate revenue based on an average tariff level, as consumption levels differ by customer, resulting in different average charges.
- Utilities have different Lifeline tariffs, in both level and structure, making any estimation on a national basis extremely difficult.
- Utilities similarly have differing cross-subsidy levels. This is dependent on the customer composition and the tariffs developed over time. In most instances these are only just becoming visible to the system, as cost of supply studies mature and the instances of 'above cost' and 'below cost' customer tariffs, and resultant levels of cross-subsidy, become apparent.

Adding to the complexity is non-payment or 'non-technical losses' (an unfunded part of the EDI). The data indicates a strong correlation between rising electricity tariffs and "squeezing out" of FBE allocations[24], and the rise of non-technical losses (Eberhard, 2015). An estimated 11 million households qualify for an energy subsidy (National Treasury, 2022), but only 1.9 million households are currently receiving FBE (Stats SA, 2024b).

Reaching a national 'quantum' for the affordability-revenue gap is difficult and requires much more detailed work, but indicative results provide critical insight. The data is expected to improve as more municipal cost of supply studies are finalised.

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[24] Partly due to (1) the change in subsidy targeting method, which moved from a blanket approach (based on area or connection size) to one of self-registration, and (2) the smaller budget allocations to electricity when municipalities needed the money for other unfunded services, notably water.

10.2 Structural issues emerging

The Local Government Equitable Share (LGES) algorithm only covers ~60% of the actual cost of the 50 kWh/month FBE, when all (fixed and variable) costs are considered (Moshoete et al., 2024). Current contributions cover the energy cost and operations and maintenance, but not the network capacity costs (fixed).

On a national scale and working off the assumption (not actual, but policy) that all households that are identified as needing basic service provision by Treasury and who are already electrified (~9 million) receive FBE, this would represent an amount of some R7.1 billion that is not covered by the LGES per year, contributing to the structural debt (gap between revenue and cost) within the EDI sector.[25]

Increasingly stringent indigent registration requirements, and the use of LGES to fund other service delivery gaps (notably water), greatly reduces the support required to fund electricity for poor households. Local tariff decisions to enlarge the provision, e.g. providing more than 50kWh FBE are often not matched by sufficient revenue planning.

The Lifeline tariff aims for cost recovery at 350 kWh/month. However, too few kWh beyond 350 are being consumed, leaving the revenue gap entirely dependent on cross-subsidies from other customer groups. This gap widened with the drastic cost increases post 2008 and tariffs unable to track this.

In total, i.e. the estimated national underfunding from below-cost tariffs is **~R30 billion annually** (Barnard, 2025b), which includes the impact of inadequate allocation of the energy-related element of the LGES grant. **This figure is set to grow.** Why? In future, there will be structural changes in wholesale costs – driving both capacity and energy costs up for servicing residential users with "peaky" demand. Electricity prices will also increase to meet required sector growth and reliability. This is further explored in section 11: "Outlook for pricing and policy implications".

It is estimated that ~R15 billion of this underfunding is currently covered through a non-transparent cross-subsidy (but, as noted above, not evenly covered).[26] **Not only does this leave an annual shortfall in the sector of approximately R15 billion, *but the cross-subsidy itself will erode as costs become more cost-reflective*.**

The reliance on cross-subsidy is potentially larger than anticipated, and uneven, i.e. those municipal utilities with limited customer mix (mostly poor households and limited commercial

[25] Calculations by SEA assuming: (1) 80% of identified poor customers are electrified (Statistics SA General Household Survey 2023 notes 2.2 billion unelectrified households, whilst Treasury DoRA 2022/23 identifies 10.9 million households as indigent); (2) 80% of R14 billion LGES for energy service (Treasury DoRA 2022/23) is for the provision of electricity, rather than energy, services (based on share of indigent customers that are electrified), i.e. R11.2 billion; (3) that this R11.2 billion only covers 60% of the total cost (calculated as R18.6 billion), as per study by Moshoete et al., 2024.

[26] Calculations undertaken by SEA, based on available cost of supply studies, which provided indicative costs to service domestic customers, the quantum of FBE transfers, as well as an indication as to the scale of inter-tariff cross-subsidies. It must be noted that this is indicative only. Data will improve as more cost of supply studies are finalised.

and industrial customers) are unable to source this contribution and become more indebted over the years. The ability to draw on cross-subsidy is also under threat, as behind-the-meter consumption /efficiency increases (with subsidy held in volumetric charges) and tariffs in each customer class are moving to greater cost-reflectivity.[27]

As cost of supply studies consolidate the picture, it is likely that levels of cross-subsidy imposed on higher consuming customers will be deemed 'unfair' or 'uneconomic'. The size of this threat to sector sustainability requires that government at all levels must develop a clear idea of the existing level of cross-subsidy and policy direction on this – and a related implementation plan. Immediately, distribution utilities will need to (a) ensure that indigent registers reflect those who qualify for free basic services (a), develop initial cross-subsidy frameworks (policy and design); and (b) develop tariff pathways to show how current tariffs will move to greater cost-reflectivity, with a necessary reduction in cross-subsidy levels.

10.3 Losses – an affordability barometer

The assessment provided is based on clarifying the gap between cost and revenue, considering current available sources of revenue. Addressing affordability also requires an assessment of the ability to pay – to establish the tariff that would ensure low-income customers remain on the grid.

There are multiple ways to establish what households can afford to pay – a worthwhile exercise, requiring extensive on-the-ground surveys, etc. There is a need to develop a greater understanding of the cost-benefit threshold to address the question of where to peg basic service support in the electricity sector (Ledger, 2021).

Indications are that where households face steep price increases (through tariff increases or a subsidy squeeze), losses increase (NEDLAC, 2009). This points to a phenomenon whereby electricity unaffordability leads to a market for criminal enterprises, with poor customers effectively 'grid defecting', buying power from illegal dealers. Given South Africa's blanket electrification, and large urban centres that are difficult to police, electricity wires are extremely available to such enterprise.

This relationship between price and 'defection'/funding gap is important to understand: if a customer moves off the grid and is served through cheaper, but illegal alternatives, the units provided by the utility remain the same, but the utility loses the entire payment contribution by that customer.

Eskom and the Department of Electricity and Energy are exploring raising the FBE quantum to draw customers back into the formal-paying grid. The assumption is that the increasing cost of the higher FBE quantum (proposals range from 100kWh to 350kWh) will be offset (partially or fully) through having a paying customer. Substantial work needs to be done to establish the affordability level, with long-term strategies to optimise revenue on the grid – whilst not leaving municipalities with a revenue gap.

[27] In the case of residential customers, with very "peaky" use, the cost of servicing their peak demand capacity and energy is very high, but is currently masked by average, smoothed tariffs. Once tariffs are cost-reflective, subsidising this high-cost user will be even more difficult. Burdening fixed charges with heavy subsidies may also push wealthier customers off grid.

Fixed charges and time-of-use tariffs cannot fairly be brought into a tariff structure for low-income households, who have limited upfront cash and limited ability to shift usage or invest in efficiencies. Policymakers must urgently clarify the scale of subsidies and set realistic affordability thresholds, which account for low-income 'grid defection'. Subsidisation mechanisms and levels must be addressed in policy, be transparent and located within the system in fixed charges that cannot be bypassed by users. Equity, cost-recovery and grid stability must be pursued together.

11 Outlook for pricing and policy implications

11.1 The pricing trajectory

Based on a rough assessment of the level of both inefficiency (over-charge) and under-expenditure (under-charge) in the ESI, the indication is **that electricity tariffs are currently too low to fund the expenditures required to provide an efficient and effective electricity service.** Tariffs need to increase by an indicative 8 – 28% to meet *current* funding requirements (Walsh, 2025)[28]. Additional future requirements will push this up further, but the extent is unknown. The introduction of a wholesale market should, in theory, ensure that this is still the lowest cost pathway.

Electricity tariffs must also be restructured to include higher fixed charges and a greater ability to reward flexibility to more accurately reflect underlying costs. This is *before any market reform impacts are considered*.

Inefficiencies abound and must be addressed to support affordable tariffs: In the wholesale part of the industry, Medupi, Kusile and many coal contracts have been inefficient, largely due to corruption, cost overruns, design flaws, aging infrastructure and delayed capacity expansion, which have driven high maintenance costs and the use of costly generation to manage capacity shortages. Employee-related costs are high relative to global benchmarks. At the distribution level, losses require urgent attention. This includes addressing the complex issue of 'illegal enterprise', which – with the rise of vandalism – requires engagement with the security cluster. Interest on debt to Eskom across municipalities is a serious pain point that requires national attention: much of the debt to Eskom was incurred through sales downturn during COVID and loadshedding.

While inefficiencies mean that expenditures are too high in some areas, it is too low in others, particularly in terms of investment in assets. There has been persistent underinvestment in new capacity (hence loadshedding) and in the maintenance and refurbishment of network infrastructure (particularly by municipalities). In municipalities, further under-funding has taken place through structural under-accounting of depreciation and overheads (where the utilities are integrated into municipal systems and do not adequately pay for these)[29]. Tariffs must increase to meet these investment requirements. While data is poor and the level of inefficiency and underspending is difficult to quantify, estimates suggest that underspending outstrips any efficiencies that may be gained, and expenditure needs to increase in aggregate.

Generation capacity is currently inadequate and must be expanded. Power system modelling undertaken to date shows costs increasing under all future generation mix pathways (Figure 9).

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[28] This is indicative only, based on data available at the time (Eskom cost to serve and tariff application, municipal D-forms, etc.). The large range is indicative as to the uncertainty surrounding all the factors that went in to generating this estimate.

[29] Accounting for overheads is poor. Good data to determine the extent of under- or over-accounting does not currently exist. This must be addressed through the introduction of ring-fenced financial statements for the municipal electricity distribution service. While some municipalities may currently over-allocate overheads to electricity distribution, available reporting data in D-forms suggests that most under-allocate these costs.

Together with associated investments in ancillary services and the transmission grid to enable this capacity, this will place **further upward pressure on tariffs**.

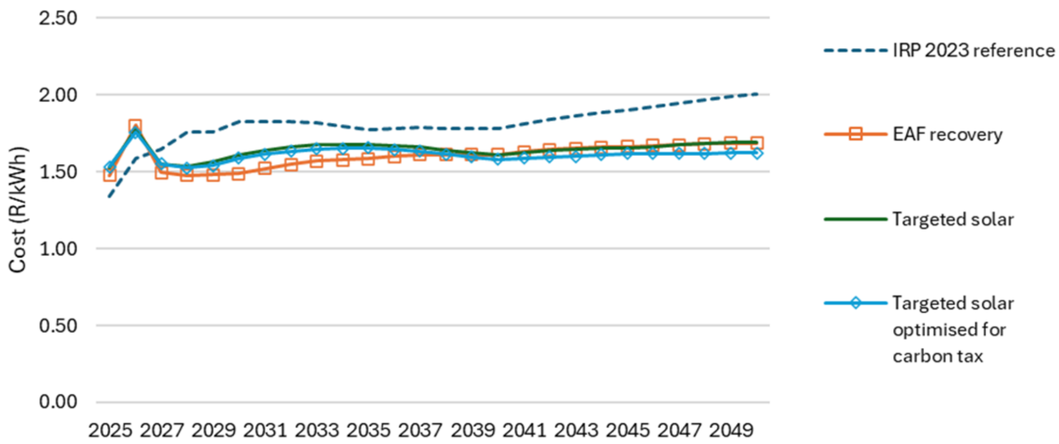

Figure 9. Indicative energy cost trajectories under alternative future generation mixes. Source: Modelling undertaken by Meridian Economics https://meridianeconomics.co.za/wp-content/uploads/2024/02/Comparative-Analysis-of-IRP-2023-cost-assumptions.pdf. Additional data supplied in personal communications.

Tariff level trajectory: Firstly, prices will go up to cover the cost of improving and expanding the current electricity system (at generation, transmission and distribution). Improved maintenance, investment in refurbishment and grid strengthening will improve reliability and ensure long-term security. Expanding the transmission grid will enable new power plants to connect to the grid. Fuel and labour costs are expected to rise, often above inflation.

Secondly, prices will go up to cover the cost of building new power plants and supporting national economic recovery. Eskom's power plants are getting old. Older plants are more expensive to run and – when they are retired – they will need to be replaced by new plants.

Lastly, the introduction of competition will exert a downward pressure on prices, ensuring the electricity supply is the cheapest possible. In sum, **there is no future in which electricity tariffs go down, but there is a lowest cost pathway.**

Tariff structure trajectory: Tariff restructuring is required to align charges with services rendered, with more costs needing to be received through fixed charges. Typically tariff structures include:

- A **fixed customer charge**: Related to metering infrastructure and billing administration.
- A **fixed capacity-based demand charge**: This covers transmission and distribution networks, based on size of connection (fixed notified maximum demand) and actual capacity used (fixed-variable maximum demand).

  Given that poorer consumers cannot afford to pay fixed charges, these would be partially included in volumetric (consumption) tariffs for 'Lifeline' (or similarly designated) customers, or funded through subsidy.

- A **volumetric, time-of-use energy charge**: This variable cost will be reflected by a price that changes throughout the day or by season, being most expensive during peak demand (evenings and mornings – especially weekdays; and during the winter months).

Customers in the wholesale market (i.e. distribution utilities and very large industrial customers) will be exposed to energy charge volatility, and will also be 'balance responsible parties', i.e. where their supply or demand varies from what they have 'offered' the market, they will pay penalties or receive a reward, based on whether the variance harmed or helped system stability.

"Captive customers" (including all households) will have a regulated tariff, buffered from volatility through hedging contracts undertaken by the utility (and likely the state in some form).

11.2 Tariffs are already increasingly unaffordable

The key issue in achieving cost-reflective tariff levels and structures is that electricity tariffs are increasingly unaffordable. Electricity price increases have consistently exceeded inflation since 2007, by substantial margins: between 2007 and 2022, the average Eskom tariff increased by 450% (Ismail & Wood, 2023). At least 55% of South African's are already facing some electricity affordability constraints, forced to make choices between energy and nutrition and households within the food poverty line (25% of all households) already spending above the 10% energy poverty threshold (Walsh, 2025).

Indications are that cost-reflective fixed tariffs that account for historic underfunding and assume that Eskom recovers 20% of its costs as fixed charges, would be around R800-R1000/month for a 20 Amp connection and R1800-R2300/month for a 60 Amp connection. This is untenable for low-income households, pushing electricity cost up to as much as 30% of household income. For wealthier households, this level of fixed charge runs the risk of 'grid defection', where the annual fixed costs are comparable with a 5-year return on investment required for a mid-income households solar and battery installation (approximately 8kVA and 15kWh battery).

Customers typically consider going off-grid for two reasons: unreliable supply or high costs. As tariffs rise, especially fixed charges and when overloaded with subsidies, and reliability declines, off-grid alternatives become more attractive. When grid power is both costly and unstable, the relative value of off-grid solutions improves (Sims & Euston-Brown, 2023). To avoid this outcome, South Africa must prioritise grid reliability through capacity investment and carefully managed subsidy levels. With entirely 'off-grid' solutions reaching a degree of 'grid parity', consideration should be given to funding a portion of system costs, particularly those related to social equity, through the **national fiscus** rather than through tariffs alone.

11.3 What are the options for funding the ESI in future?

One option is to significantly increase tax-based funding for generation, transmission and distribution. Yet, fiscal constraints limit this approach, and its success depends partly on a reliable energy system spurring economic recovery. Local property taxes could also help fund distribution infrastructure, but municipalities with a small local economy and a large portion of low-income households may struggle to raise the funding required.

A more moderate solution is to expand and restructure subsidies so that poor households pay only for the electricity they consume, with fixed costs covered through public transfers. This would improve affordability and reduce reliance on wealthier users for cross-subsidies, protecting both equity and financial sustainability across the system.

Table 2. Options to fund the electricity supply industry (Walsh, 2025)

Tariffs	Taxes	Transfers
• Reduce reliance on tariffs? • Could go as far as tariffs covering energy costs only for low-income households? • Remove VAT on energy tariffs for poor households? Or all customers?	• Fund generation capacity, transmission and distribution through taxes? • Property rates for distribution costs and/or streetlighting, but raises issues with Eskom vs. municipal distribution?	• Substantially increase transfers to cover fixed costs incurred in supplying electricity to poor households?

The foundation for affordability must be the lowest-cost electricity mix, and improved governance and system performance. An energy package approach, seeking to bring down or shift peak demand, also requires consideration. For example, this could include load restriction to a 20 Amp connection to qualify for subsidy, utilisation of gas for cooking, or innovative daytime “cheap” solar energy access.

Ultimately the inclusion of poor households requires subsidisation and a ‘grid for all’ approach that is optimal for all. It may be that existing inefficiencies, if addressed, can support greater levels of subsidy: the cost of subsidy (meeting the affordability-revenue gap) must be assessed against the cost to the system of ‘grid defection’, or non-technical losses.

12 Conclusion

The South African electricity system urgently requires significant capital investment. The state cannot anchor the investments required. The introduction of a wholesale market can attract the required investment and deliver important efficiencies.

The efficiencies offered by the wholesale market should drive the least-cost price trajectory. Despite this relief, upward pressure on costs, associated with years of underinvestment and much-needed capacity expansion, will mean rising electricity tariffs in the coming years.

At the same time, energy sector disruption and transition require a restructuring of tariffs to include a much higher share of fixed charges, better reflecting the underlying cost drivers.

Electricity tariffs are already unaffordable to many users in South Africa. If there is not a mechanism to deal with this, we face living with year-on-year increases that are socially and economically impossible, or the cannibalisation of infrastructure,[30] with consequent loadshedding and related economic impact and job losses.

A state-led pricing model with average cost tariffs may appear simpler and fairer, but the state cannot fund new capacity. Energy transition disruptions, along with the need to attract private capital, require dynamic pricing offered through a market platform.

A wholesale energy market can offer efficiency and lower prices in the long term, but this impact is limited in the short term, when the price is set by coal and the network demands large capital expenditure. However, wholesale market pricing (e.g. short-run marginal cost bids) offers an important signal to attract the investment required for capacity expansion and system flexibility.

A market is necessary to ensure the most efficient pricing outcome and a robust, low-carbon economy[31]. This reform process must include a detailed examination of the social equity requirements, ensuring that we develop a grid for all. This includes 'buffering' (or hedging) of market risks associated with price volatility, and meeting the affordability-revenue gap (likely covering most of the capacity/fixed costs of poor households and the provision of a basic service). Social equity must be set to retain grid participation – at both ends of the market. This may require new electricity supply industry funding approaches, with more of the costs recovered outside of the system (rates and taxes). Electricity price increase is a fundamentally political issue. Coordinated action is needed.

[30] Where tariffs are kept artificially low by deferring maintenance or refurbishment of infrastructure, which leads to eventual infrastructure collapse.

[31] The inter-day and intra-day marginal cost bidding in a wholesale market favours low-marginal cost technologies (such as solar and wind) and flexible, fast-ramping technologies (such as batteries, demand response and low-utilisation peaker gas plants).

13 Strategic recommendations for decision-makers and social partners in pricing reform and market evolution

The following strategic recommendations aim to complement and support the extensive policy and implementation reform work underway.

- **Anchor market reform in national leadership and policy**
  - Ensure an all-of-government and all-of-society approach. Pricing is hugely political and therefore requires a national strategy and commitment. Back-tracking will lead to huge costs.
  - Align EPP with market requirements, including social equity requirements.
  - Define 'eligible market participant' in the Market Code and in ERAA's definition of municipal reticulation, and provide any associated legal and revenue support work municipalities may need in the transition.
  - Ensure National Treasury Municipal Fiscal Framework and Subsidy Policy aligns with market requirements, social equity requirements and municipal market participation, including consideration of potential 'equalisation' or 'bail out' funds.
  - Ensure key policy commitments are brought into the market through mechanisms such as renewable minimum price caps for low carbon energy, or social equity provisions.
  - Secure political buy-in, backed by transparent implementation plans, on pricing and system subsidies.
- **Build technical capacity and market literacy**
  - Invest in training and institutional support for regulators, municipalities and market participants to ensure optimal system operation.
  - Active citizen oversight will be important: build platforms for engagement and knowledge-sharing.
- **Implement tariff reform and improve transparency**
  - Support the unbundling of electricity tariffs across the sector to reflect actual cost drivers and the balancing of cost-reflectivity with other tariff principles of affordability and sustainability.
  - Develop NERSA guidelines that support improved data collection (D-form technical and financial inputs), accounting practices in costing method, tariff standardisation, and cost-reflective and socially equitable pricing across all customer categories.
  - Extend the National Treasury City Support Programme Metro Trading Services work (or key elements thereof, e.g. ringfencing of costs) to all municipalities.
- **Phasing in market participation and mitigate pricing risk**
  - Clearly and transparently define Eskom Generation's path to competitive neutrality and how legacy contracts will be managed.

- Articulate the responsibilities of the NTCSA, the role of traders and the framework for municipal participation.
- Ensure the NTCSA is fully separated from Eskom, for independence.
- Urgently clarify the role and financing of the "supplier of last resort" (and link to considerations of 'bail out' mechanisms or funds).

- **Invest in grid modernisation to support flexibility and grid capacity – and optimisation of innovation**
  - Create enabling conditions for investment in flexible generation, storage and digital grid infrastructure – this is key to ensuring optimal forecasting and efficient pricing.
  - Ensure regulatory certainty and streamlined processes to enable third parties to provide innovative services within the distributed resources space, e.g. virtual power plants.[32]
  - Enable innovation critical for system efficiency opportunities, e.g. grid forecasting software, or 'sharing' of excess solar with low-income households or enterprises.
- **Reform and support municipal utilities**
  - Ensure municipal distributors are supported to improve financial and operational governance of utilities and develop market literacy (this is complex and cross-cutting).
  - This must include developing a clear understanding of tariff pathways and related cross-subsidy impacts; local subsidy policy and plans must be developed to protect poor consumers and municipal sustainability.
  - Strengthen regulatory oversight of license conditions.
  - Fast-track the clarification of market-related EDI issues, such as how finance 'gaps' will be addressed, e.g. penalties for inaccurate load forecast or difference between market price and regulated tariff.
  - Fast-track EDI reform and related institutional/regulatory reform to enable distribution sector participation, e.g. MFMA in relation to wholesale procurement, separation of wires and retail business functions, etc.
  - Pilot municipal procurement from IPPs through the IPP Office, or other institutional arrangements that can address the high transaction costs, towards initial energy portfolio development, whilst attracting investment and price stability through long-term power purchase agreements.
- **Consider alternative funding mechanisms for the electricity supply industry: aligning subsidy policy with just energy transition goals**

[32] Where distributed resources, such as rooftop PV, batteries and flexible demand, are aggregated and coordinated by a third party, using software, to provide grid services and balance supply and demand.

- Consider tax funding to support generation, transmission and distribution funding, and local property taxes[33] for distribution sector funding.
- Consider expanding and restructuring subsidy funding, based on:
  - A deeper understanding of the gap between affordability and the cost to serve low-income households, and how existing cross-subsidy is under threat.
  - A deeper understanding of social equity support required to maintain grid participation by poor households.
  - A deeper understanding of the point at which higher-income customers "defect" from the grid due to high fixed costs – a mechanism that can be used for cross-subsidy.
- Ensure subsidies are more transparent and better targeted.
- Establish ongoing efforts to monitor electricity subsidy impact and the affordability-revenue gap.
- Implement alternative energy options, both efficiency and other energy sources, for greater resilience and addressing peak electricity reduction; within an energy democracy approach that involves communities more directly in energy development projects and household energy access alternatives.

These recommendations are interdependent and require coordinated, multi-sectoral implementation.

[33] Noting that local taxes tend to be less equitable than national taxes, since municipalities with a smaller economy will receive fewer local taxes. Then there's also issues of Eskom vs. municipal distribution infrastructure.

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