UzEnergyNews

GLOBAL ENERGY REVIEW · ANNUAL

Emerging Energy Outlook 2026

How the developing world powers its transition — ten economies benchmarked against the EU-27 and the OECD on the indicators that price risk.

Economies: Türkiye · Uzbekistan · Kazakhstan · India · Pakistan · Indonesia · Vietnam · Nigeria · South Africa · Kenya

Benchmarks: EU-27 · OECD

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Foreword

The global energy transition is most often described from the perspective of the advanced economies — their targets, technologies and timelines. The greater part of future growth in electricity demand, however, will occur elsewhere. Over the next two decades, almost all of the increase in electricity demand is expected to arise in the developing world, where more than five billion people still consume a fraction of the electricity available to households in Europe and North America.

This report examines that part of the world directly. It assesses ten developing economies — Türkiye, Uzbekistan, Kazakhstan, India, Pakistan, Nigeria, South Africa, Kenya, Indonesia and Vietnam — and measures each against two reference points that the advanced economies establish in practice: the **EU-27** and the **OECD**. The indicators have been selected deliberately, as those an investor, lender or regulator uses to assess and price risk: per-capita consumption and income, the generation mix, electricity access, tariffs and subsidies, grid losses and investment, sovereign ratings and the cost of capital, carbon intensity and climate commitments.

A single conclusion runs through all of them. These economies do not lack ambition; almost every country examined maintains a renewables target, an electrification programme and a reform agenda. What constrains them is the cost of capital and the condition of the grid. Utility-scale generation is financed at two to three times the cost prevailing in Europe, while the networks intended to carry its output are older, less efficient and persistently underfunded. The pace of the transition will therefore be determined less by the decision to build than by the cost of finance and the capacity of the network to absorb new generation.

All data in this report is drawn from public sources and benchmarked transparently. Uncertain figures are identified as such, and where our estimates differ from official plans, both are presented.

— The Editors, UzEnergyNews

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1 · The Developing World at a Glance

IN BRIEF - Ten developing economies spanning **~2.5 billion people** generate the demand growth that will shape global energy markets — yet most consume a fraction of EU-27/OECD power per person. - The binding constraints are not ambition but **the cost of capital (2–3× advanced economies)** and **the grid.** - Only **3 of 10** carry an investment-grade sovereign rating; the rest pay a structural risk premium on every project.

Headline panel — key metrics at a glance

COST-OF-CAPITAL GAP	**GRID INVESTMENT**	**PER-CAPITA GAP**
~2–3×	**~$600 bn/yr**	**150 → 7,500**
Solar WACC: developing 8–13.5% vs advanced 5–6.5%	Global grid need by 2030 (must ~double from ~$300 bn) · EU-27 ~€58–75 bn/yr	kWh/person: Nigeria 150 … vs EU-27 ~6,000 / OECD ~7,500
INVESTMENT GRADE	**CARBON SPREAD**	**ACCESS DEFICIT**
3 of 10	**6×**	**~57–100%**
Only KZ, IN, ID investment grade; rest speculative	gCO_2/kWh: Kenya 112 (geothermal) → South Africa ~850 (coal)	Nigeria ~57% with the world's largest absolute deficit; most others near-universal

Snapshot table (2024–2026, public sources; see Annex C for vintage)

Country	Pop (mn)	GDP/cap ($)	Capacity (GW)	Per-cap elec (kWh)	RE % gen	Resid. tariff (¢/kWh)	Rating (S&P)	Solar WACC	Carbon (gCO_2/kWh)
Türkiye	85.5	15,470	122.5	~3,900	~44	~6.0	BB-	proxy[1]	~395
Uzbekistan	~38	3,850	27.3	~2,200	~20	~4.8	BB	~8–9[1]	473
Kazakhstan	20.3	14,000	25.3	~6,000	6[2]/15	~6.3	**BBB-**	~7–9	~600
India	1,463	2,820	513.7	~1,395	~22–24	~7.4	**BBB-**	~10–11.5	708
Pakistan	~250	1,485	~45.9	~636	~5[2]/64[4]	~11.2	B-	~12–16[1]	~245
Indonesia	~283	4,925	100.6	~1,300	~18–20	~9.9	**BBB**	9.4	~610
Vietnam	~101	4,700	82.4	~2,650	~45	~8.6	BB+	9.0	681
Nigeria	~235	835	~13[3]	~150	~30	~15–16	B	~13–15[1]	~400
South Africa	~63	6,300	~58	~3,200	~14	~12.0	BB	~11–13.5	~673–850
Kenya	~57.5	2,206	3.2	~190	~83	~22	B	~8.5–9	~112
EU-27	449	43,150	~1,250	~6,000	47	~31	~AA	**4.7–6.5**	213
OECD	~1,380	48,300	~3,300+	~7,500	~33	13–35	mostly IG	~5–6.5	~300–350

[1] Not in the IEA Cost of Capital Observatory; figure is a Damodaran-based proxy, presented as approximate. [2] Renewables excl. large hydro. [3] Installed ~13 GW but only ~4 GW delivered. [4] Pakistan: 64 = low-carbon generation including hydropower and nuclear, not renewables alone. Full sourcing in Annex B; data vintage in Annex C.

Executive Summary

The center of gravity of global electricity demand is moving toward the developing world, while the terms on which these economies finance and build their power systems have not converged with those of the advanced economies. The ten economies examined in this report account for a substantial and rising share of incremental electricity demand; India alone adds more generation each year than many countries possess in total. The central finding of this report is that, in the present phase of electrification, the modernization and management of the electricity grid is as decisive a matter of national and international security as generation capacity and the diversity of the generation mix.

1. The per-capita consumption gap remains wide. Consumption ranges from approximately 150 kWh per person in Nigeria and 190 in Kenya to around 6,000 in Kazakhstan, compared with approximately 6,000 in the EU-27 and 7,500 across the OECD. Each step a developing economy takes toward these benchmarks represents both additional demand that the system must serve and additional network capacity that must be financed.

2. The cost of capital is the principal barrier. Utility-scale solar is financed at approximately 8–13.5% across these markets — and higher in those without a sovereign rating — compared with 5–6.5% in Europe and North America. This two-to-threefold difference, confirmed by the IEA's own cost-of-capital data, raises the cost of every megawatt of capacity and every kilometre of line. Only three of the ten economies — Kazakhstan, India and Indonesia — hold an investment-grade sovereign rating; the remainder carry a sovereign risk premium that procurement design alone cannot remove. Kazakhstan, rated Baa1, finances on terms close to those of the advanced economies.

3. The binding constraint is the grid rather than generation. Across South Africa's transmission queue, India's evacuation bottlenecks and Vietnam's curtailed solar output, network capacity is increasingly the limiting factor. Global grid investment must approximately double, to around USD 600 billion per year by 2030, while the EU-27 alone plans EUR 58–75 billion per year. Developing economies, by contrast, invest persistently below requirement, and grid losses range from approximately 6% in Vietnam to 18% in Pakistan and, on a basis that also includes commercial and collection losses, around 39% in Nigeria. A significant part of new capacity is now being added outside the grid: Pakistan's 27–33 GW of distributed rooftop solar is largely absent from official statistics.

4. Generation mixes, and carbon intensity, differ by a factor of six. Several economies remain coal-dependent — India (around 70% of generation), Indonesia (67%), South Africa (82%) and Kazakhstan (54%) — while others are already predominantly clean, including Kenya at around 83% renewable generation from geothermal and hydropower, and Vietnam and Türkiye near 45%. Carbon intensity ranges from approximately 112 gCO_2/kWh in Kenya to 850 in South Africa, against 213 in the EU-27. The generation mix a country has inherited largely determines the difficulty and the cost of its transition.

5. Tariff design and financial viability determine which countries can build. Cost-reflective pricing remains the most difficult reform, as illustrated by Pakistan's circular debt, Nigeria's Band A tariff, Indonesia's frozen subsidies and Uzbekistan's social-norm tariff structure. Where tariffs do not recover cost, investment cash flow erodes and customers with the means to do so leave the grid. It is important to recognize that the amounts paid on electricity bills are not solely consumption expenditure; investment in energy infrastructure today is a strategic commitment to the coming thirty years of a country's development.

Conclusion. The developing world will advance its energy transition not through greater ambition but by narrowing the cost-of-capital gap — through credit reform, blended finance and instruments such as the Just Energy Transition Partnerships — and by building networks quickly enough to carry the clean capacity already being added. The decisive variable of the coming decade is not the generating technology but the transformation of the grid.

Yönetici Özeti

Ağırlık merkezi kayıyor, ama ticaret şartları değişmiyor. Bu raporda incelenen on ekonomi, elektrik talebinin büyüyeceği yer — tek başına Hindistan her yıl birçok ülkenin toplam kurulu gücünden fazlasını ekliyor — ama geçişe gelişmiş dünyadan yapısal olarak daha kötü koşullarla giriyorlar. Raporun çekirdek bulgusu şu: elektrik çağında üretim teknolojisi ve çeşitliliği kadar şebekenin dönüşümü ve yönetimi de en kritik ulusal ve uluslararası güvenlik meselesidir.

1. Kişi-başı tüketim farkı yüksek seviyelerde. Tüketim, Nijerya'da kişi başı ~150 kWh ve Kenya'da ~190'dan Kazakistan'da ~6.000'e uzanıyor; AB-27 ~6.000, OECD ~7.500'e karşı. Bir gelişmekte olan ekonominin bu çapalara doğru attığı her adım, sistemin karşılaması gereken yeni talep ve finanse edilmesi gereken şebeke maliyeti demek.

2. Asıl bariyer sermaye maliyeti. Şebeke ölçekli güneş bu pazarlarda kabaca **%8–13,5** ile finanse ediliyor — notsuz olanlarda daha yüksek — Avrupa ve Kuzey Amerika'da **%5–6,5**'e karşı. IEA'nın kendi sermaye maliyeti ile teyit edilen bu **iki-üç katlık** fark, her megavatın ve her kilometre hattın maliyetini şişiriyor. On ülkeden yalnız üçü — Kazakistan, Hindistan, Endonezya — yatırım yapılabilir notta; gerisi hiçbir ihalenin tasarlayıp ortadan kaldıramayacağı bir egemen risk primi ödüyor.

3. Bağlayıcı kısıt üretim değil, şebeke. Güney Afrika'nın iletim kuyruğundan Hindistan'ın tahliye darboğazlarına ve Vietnam'ın kısıtlanan güneşine kadar, şebeke kısıtları giderek daha fazla gündeme geliyor. Küresel şebeke yatırımının 2030'a kadar **yılda ~$600 milyara, yaklaşık iki katına** çıkması gerekiyor; tek başına AB-27 **yılda €58–75 milyar** planlıyor. Gelişen ekonomiler ise kronik olarak daha az yatırım yapıyor. Kayıplar Vietnam'da ~%6'dan Pakistan'da ~%18'e ve Nijerya'da (ticari ve tahsilat kayıpları dahil) ~%39'a uzanıyor. — Pakistan'ın 27–33 GW'lık dağıtık çatı güneşi resmî istatistiklerde neredeyse görünmüyor.

4. Üretim karması — ve karbon — altı kat ayrışıyor. Birçok ekonomi kömüre kilitli: Hindistan (üretimin ~%70'i), Endonezya (~%67), Güney Afrika (~%82), Kazakistan (~%54). Diğerleri ise hâlihazırda temiz: Kenya jeotermal ve hidroyla ~%83 yenilenebilir, Vietnam ve Türkiye ~%45'e yakın. Karbon yoğunluğu altı katlık bir aralıkta — Kenya'da ~112 gCO_2/kWh'ten Güney Afrika'da ~850'ye — AB-27'deki ~213'e karşı. Bir ülkenin devraldığı karma, geçişinin ne kadar zor ve ne kadar pahalı olacağını büyük ölçüde belirliyor.

5. Tarife ve sürdürülebilirlik, kimin gerçekten inşa edeceğini belirliyor. Maliyet bazlı fiyatlama en zor reform olmaya devam ediyor. Erişilebilirlik ile yatırımı finanse eden nakit akışı arasında sürekli bir gerilim söz konusudur. Tarife başarısız olduğunda yatırımcı kaçıyor — ve şebeke yatırımları kendisini rahatlıkla ödeyen yatırımcı talebini kaybediyor. Aslında elektrik faturalarında ödenen tutarlar tamamen tüketim harcaması değildir. Şu an enerji alt yapısına harcanan her para ülkelerin gelecek 30 yılına yapılan stratejik bir yatırımdır.

Sonuç. Gelişen dünya geçişini daha çok isteyerek başaramayacak. Bunu, finansman-maliyeti farkını kapatarak — kredi reformu, harmanlanmış finansman ve Adil Enerji Geçiş Ortaklıkları gibi araçlarla — ve eklediği temiz kapasiteyi taşıyacak kadar hızlı şebeke inşa ederek başaracak. Önümüzdeki on yılın belirleyici değişkeni panel ya da türbin değil şebeke dönüşümü.

3 · Demand & Development — The Per-Capita Gap

IN BRIEF - Per-capita consumption spans a ~40× range (Nigeria ~150 → Kazakhstan ~6,000 kWh) against EU-27 ~6,000 / OECD ~7,500. - The gap is the demand reserve: convergence toward benchmark living standards is the primary driver of global electricity growth to 2035. - Income, not geography, tracks consumption — but suppressed demand (Nigeria, Pakistan) hides true latent need behind unreliable supply.

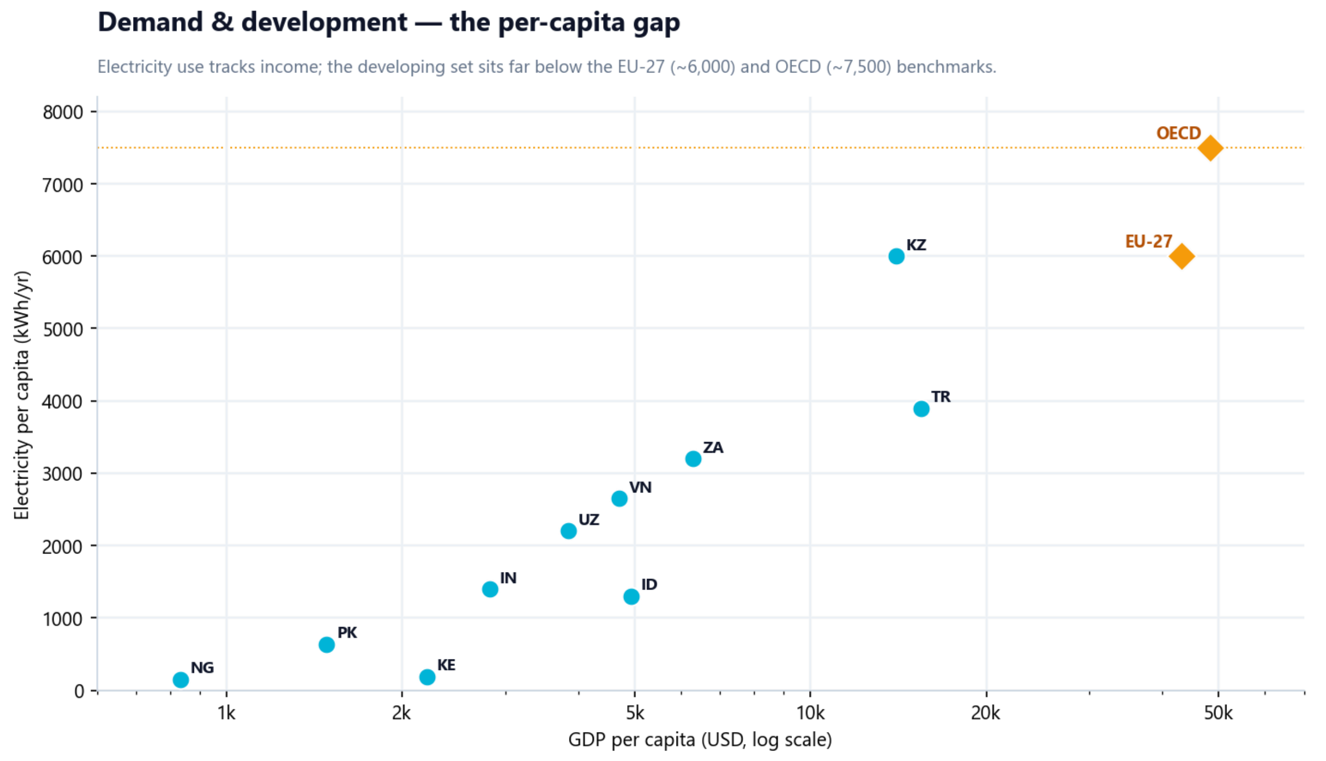


Figure §3 — Electricity use per capita against income; the developing set against the EU-27 and OECD benchmarks.

Per-capita electricity consumption across the ten economies surveyed in this report spans a range of roughly forty to one, and that range is the most direct quantitative expression of the development task before them. At the lower end, Nigeria consumes on the order of 150 kilowatt-hours per person each year and Kenya approximately 190, levels at which electricity covers basic lighting and limited appliance use but cannot yet support broad industrial or commercial activity. India and Indonesia occupy an intermediate position at roughly 1,395 and 1,300 kilowatt-hours respectively, while Vietnam, having grown rapidly over the past decade, reaches approximately 2,650. Kazakhstan stands apart from the group at close to 6,000 kilowatt-hours per person, a figure that places it essentially level with the European Union's gross consumption of about 6,000 and within reach of the OECD average of roughly 7,500. The distance between Nigeria and Kazakhstan within a single peer group illustrates that the developing world is not a uniform category but a wide distribution of energy maturities.

Income broadly tracks consumption across these economies, though not mechanically. The countries with the lowest per-capita electricity use, Nigeria at approximately 835 dollars of GDP per capita and Kenya at around 2,206, are also among the poorest, while Kazakhstan's consumption near the European benchmark accompanies an income of roughly 14,000 dollars. Türkiye, at about 15,470 dollars and some 3,900 kilowatt-hours per person, sits in the upper-middle band of the group. The correspondence reflects the role of electricity as an input to the manufacturing, services, and household activity that generate national income, and rising per-capita consumption should therefore be read as a measured indicator of development rather than as a concern in itself.

Demand growth is concentrated in precisely these economies. Where forward estimates are available, India, Vietnam, and Indonesia show the higher demand growth rates, reflecting industrialisation and expanding household connection, while Türkiye and the Central Asian economies grow at a more moderate pace from a higher base. In several markets the recorded figures understate the underlying need. Where supply is unreliable, as in Nigeria and Pakistan, consumption is suppressed by load-shedding and constrained delivery rather than by an absence of demand, so that observed per-capita levels reflect what the system can supply rather than what households and enterprises would use under stable conditions. Nigeria's installed capacity of around 13 gigawatts against delivered output near 4 gigawatts indicates the scale of that gap.

If consumption in these economies converges over time toward the European Union and OECD benchmarks, the implication is twofold. New demand on the order of several thousand kilowatt-hours per person must be met by additional generation, and that generation must be accompanied by a commensurate expansion of transmission and distribution capacity capable of delivering it reliably. Both requirements must be financed, and the cost of that financing, examined in the sections that follow, varies considerably across the group. Convergence is therefore best understood as a development objective whose pace will be shaped by the capacity of each system to invest.

4 · The Generation Mix & the Leapfrog Question

IN BRIEF - Coal-dependent systems (South Africa ~82%, India ~70%, Indonesia ~67%, Kazakhstan ~54%, Vietnam ~49% as the largest single source) alongside predominantly renewable ones (Kenya ~83%; Türkiye and Vietnam ~45% including hydropower). - Carbon intensity spans 6× (Kenya 112 → South Africa ~850 gCO_2/kWh) vs EU-27 213. - "Leapfrogging" coal is real only where resource (Kenya geothermal) or capital (Gulf-backed IPPs in Uzbekistan) allows; elsewhere coal is locked in by sunk assets and captive demand.

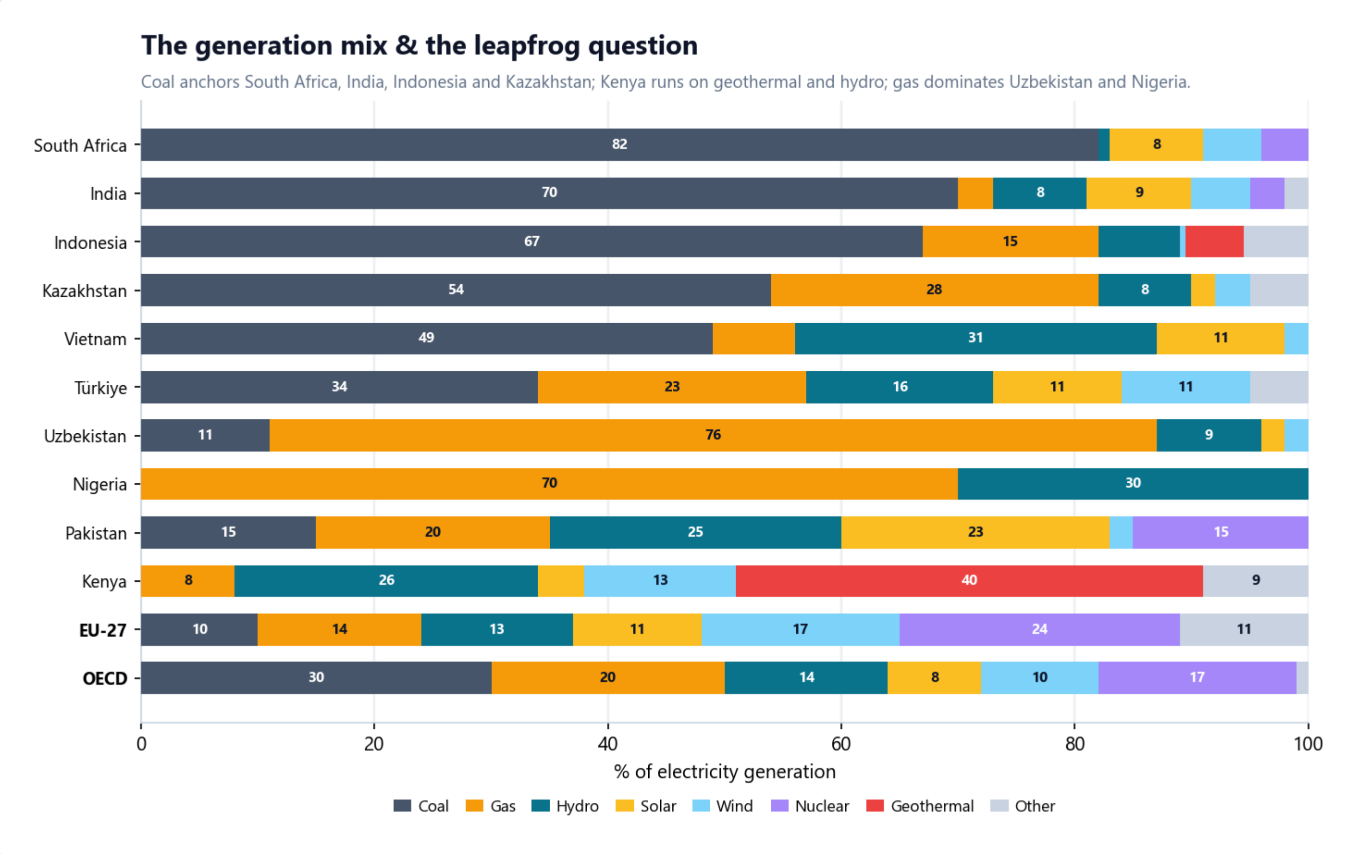


Figure §4 — Electricity generation mix by source, ten economies and the EU-27 / OECD benchmarks.

The ten economies surveyed do not share a single generation model; rather, they occupy three broad and overlapping families that condition the cost, pace, and difficulty of any transition. The first family is built predominantly on coal. Coal accounts for roughly 82 percent of generation in South Africa, approximately 70 percent in India, around 67 percent in Indonesia, close to 54 percent in Kazakhstan, and near 49 percent in Vietnam, where it remains the single largest source despite substantial additions of other generation. The second family is built principally on natural gas, most clearly in Uzbekistan, where gas supplies about 76 percent of generation, and in Nigeria, whose grid is similarly gas-led. The third family is characterised by a predominantly low-carbon generation base. Kenya draws approximately 83 percent of its electricity from geothermal and hydropower combined, while Türkiye and Vietnam each reach roughly 45 percent renewable generation once hydropower is included, illustrating that a single country can belong to more than one family at once.

These structural differences translate directly into the carbon intensity of electricity, which varies by a factor of more than six across the group. The cleanest system is Kenya's, at approximately 112 grammes of carbon dioxide per kilowatt-hour, reflecting its geothermal and hydro base. The most carbon-intensive is South

Africa's, at roughly 850 grammes per kilowatt-hour, a consequence of its established coal fleet. The remaining economies fall between these poles, and the EU-27 benchmark of 213 grammes per kilowatt-hour sits well below the coal-based systems while remaining above the most hydro- and geothermal-rich grids. The composition of the generation mix, more than the level of demand, is therefore the principal determinant of each system's emissions profile.

Against this backdrop, the question of whether emerging economies can move directly to cleaner systems, without retracing the fossil-intensive path of earlier industrialisation, is best treated as conditional rather than settled. In several cases a favourable endowment or an external source of capital appears to ease and accelerate the shift. Kenya's geothermal resource provides a domestically available, low-carbon base that few peers can replicate. Uzbekistan has attracted Gulf-backed independent power producers that bring capital and capacity to a system historically dependent on gas, and the large-scale solar build-out under way in India and Vietnam reflects a comparable mobilisation of investment at speed. In other cases the existing structure of the system makes change slower and more costly. Where substantial thermal assets remain relatively young, and where captive industrial demand is tied to specific fuels, as with the captive coal capacity serving Indonesia's metal-smelting sector, the economic case for early retirement or substitution is weaker, and the transition proceeds against the inertia of installed plant and contracted demand.

The evidence assembled here therefore points to divergence rather than convergence in generation strategy. The pace of any leapfrog depends less on stated ambition than on the interaction of resource endowment, the age and scale of existing thermal assets, the structure of industrial demand, and access to affordable capital, and these conditions differ markedly from one economy to the next.

5 · Electricity Access & the Last Mile

IN BRIEF - Access ranges from ~57% (Nigeria — the world's largest absolute deficit, ~85–95 mn unserved) to near-universal. - The last mile is increasingly off-grid: solar home systems and mini-grids (Kenya ~1.2 mn SHS; Nigeria DARES) reach where the wire does not. - 100% access ≠ reliable supply: Uzbekistan and Nigeria have full nominal access but weak quality and suppressed demand.

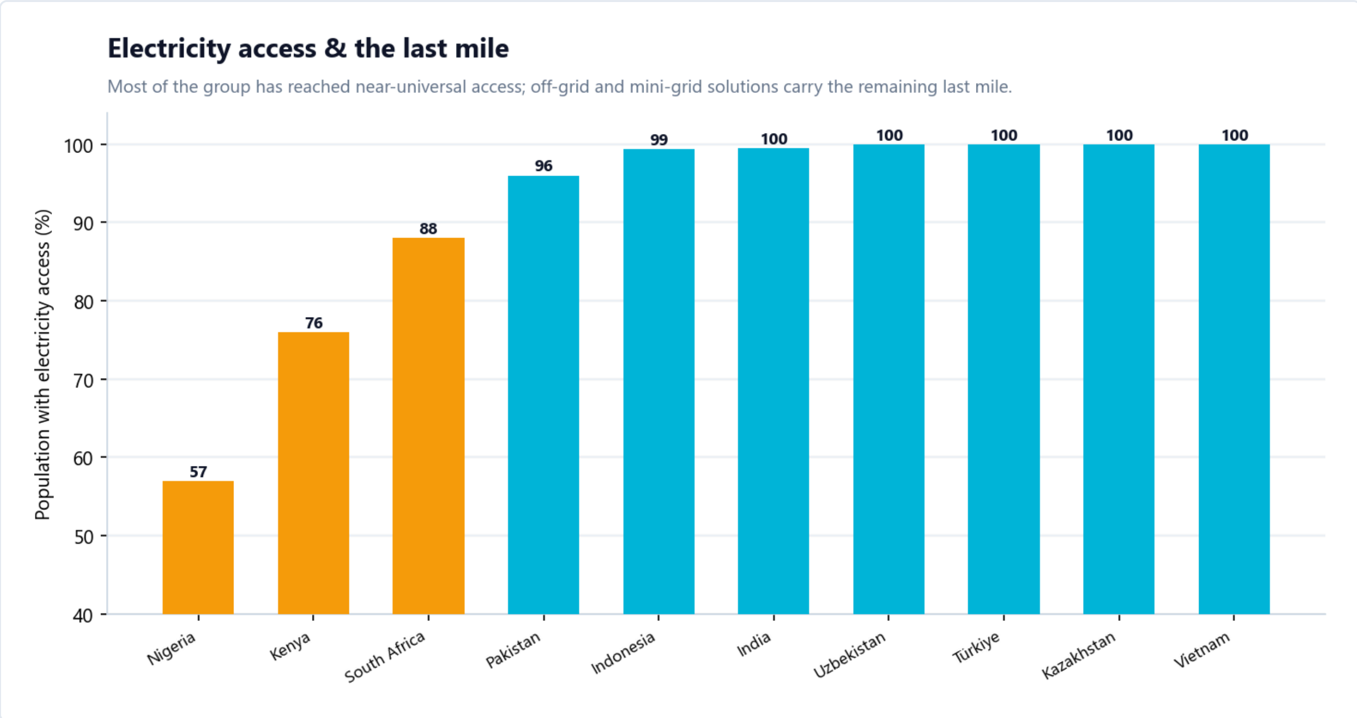


Figure §5 — Share of population with electricity access.

Across the ten emerging economies covered in this report, electricity access spans a wide range, and the distribution of that range is itself informative. At the lower end, around 57 percent of Nigeria's population has access to electricity, and access in Kenya stands at approximately 76 percent. In a middle band, South Africa reports access of close to 88 percent and Pakistan close to 96 percent. At the upper end, Türkiye, Kazakhstan, India, Indonesia, Uzbekistan and Vietnam have reached effectively universal or near-universal access, with reported rates at or very close to 100 percent. This pattern indicates that, for most of the economies considered here, the principal access challenge has shifted from connecting populations for the first time toward sustaining and improving the quality of service already in place.

The remaining gaps tend to be concentrated in areas that the central grid reaches late or imperfectly, typically rural, dispersed or low-density settlements where the cost of network extension is high relative to expected demand. In these settings, off-grid and distributed solutions have come to play a growing role in extending what is often described as the last mile. In Kenya, an installed base of approximately 1.2 million solar home systems, complemented by a developing fleet of mini-grids, has extended service to households and communities that the interconnected grid does not yet serve. In Nigeria, mini-grid programmes pursue a comparable function, providing localised supply in areas where grid connection remains distant or commercially difficult. These approaches do not substitute for the central system, but they reach populations that would otherwise wait considerably longer for a conventional connection, and they allow access to advance in parallel with, rather than only behind, network expansion.

A further consideration concerns the distinction between nominal access and reliable supply. Several of the economies that report full or near-full access continue to experience limitations in the quality and continuity of that supply, including interruptions, voltage instability and constrained hours of availability. A connection that exists on paper does not, in every case, translate into dependable service throughout the day, and the headline access figures should therefore be read alongside indicators of reliability rather than in isolation. Where supply is unreliable, a portion of underlying demand remains latent, held back not by the absence of a connection but by the uncertainty of service; households and enterprises adjust their consumption, and in some cases maintain backup arrangements, in response to that uncertainty. This suggests that improvements in reliability may release demand that present consumption figures understate.

The situation in Nigeria, where access is the lowest in the group at around 57 percent, is best understood as a factual description of where the country currently stands rather than as a single summary judgement. It reflects a large and partly dispersed population, the scale of the connection task that remains, and the particular weight that distributed and off-grid solutions are likely to carry in addressing it. Read together, the figures in this section point to two distinct but related agendas across the emerging economies considered here: completing access where coverage remains incomplete, and converting nominal access into reliable, continuous supply where connections already exist.

6 · Tariffs, Subsidies & the Viability Gap

IN BRIEF - Residential tariffs span ~4.8 ¢/kWh (Uzbekistan) to ~22 ¢ (Kenya); the question is not level but cost-reflectivity. - The viability gap drives circular debt (Pakistan ~PKR 1.6 tn) and grid defection (Pakistan distributed solar 27–33 GW off the books). - Reform is universal but partial: Band A (Nigeria), social-norm slabs (Uzbekistan), frozen subsidies (Indonesia), IMF-conditioned cost recovery (Pakistan).

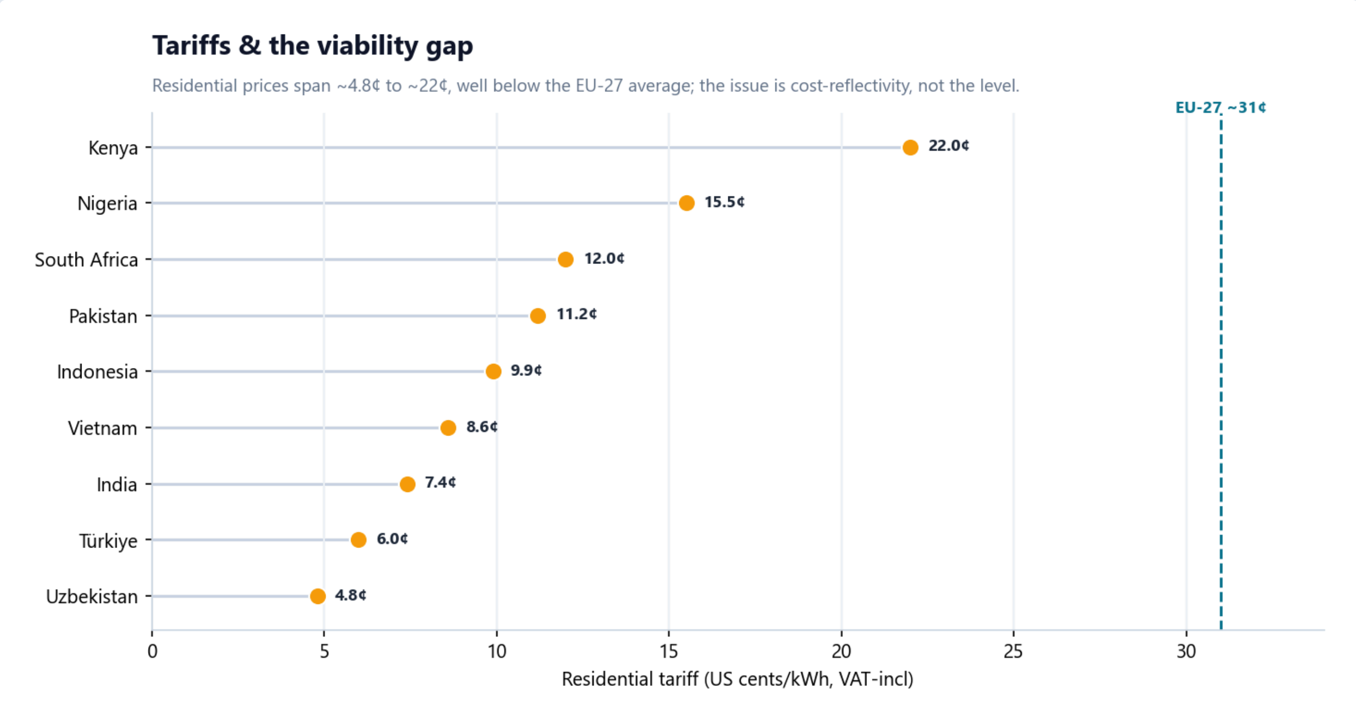


Figure §6 — Residential electricity tariffs, VAT-inclusive US cents per kWh, against the EU-27 average.

The residential tariffs observed across the emerging markets in this Outlook span a fivefold range when expressed on a comparable basis, in VAT-inclusive US cents per kilowatt-hour. At the lower end stand Uzbekistan at approximately 4.8 and Türkiye at approximately 6.0, followed by India at approximately 7.4, Vietnam at approximately 8.6, and Indonesia at approximately 9.9. The upper portion of the range is occupied by Pakistan at approximately 11.2, South Africa at approximately 12.0, Nigeria's cost-reflective Band A at approximately 15 to 16, and Kenya at approximately 22. Each of these levels sits well below the EU-27 average of approximately 31, a comparison that is useful for orientation rather than for direct judgement, since purchasing power, household incomes, and the underlying cost of supply differ substantially across these economies.

The central matter for an investor or a policymaker is not the headline level of the tariff but its degree of cost-reflectivity, and consequently the gap between a price that households can reasonably afford and the cash flow required to fund and maintain the network that serves them. Where this gap is wide and persistent, it accumulates within the sector in identifiable ways. Pakistan offers the most documented case, with circular debt of the order of PKR 1.6 trillion and a cost-recovery path that is conditioned, in part, by its programme with the International Monetary Fund. Several jurisdictions have responded with structural measures that merit neutral description. Nigeria has introduced a cost-reflective tariff for its Band A customers, who receive a higher standard of supply in exchange for prices closer to the economic cost. Indonesia has maintained subsidised residential tariffs at frozen levels for an extended period, deferring adjustment in favour of affordability. Uzbekistan applies a social-norm slab structure, under which an initial block of consumption is priced more favourably and consumption above the threshold is charged at higher rates. Kazakhstan has framed its approach as a tariff in exchange for investment, under which regulated price increases are tied to commitments to renew ageing assets.

These differing arrangements share a common underlying mechanism. Where tariffs do not recover the full cost of supply over time, the cash flow available for investment weakens, the renewal of network assets is deferred, and the financial position of the utility deteriorates. A secondary effect compounds the first, in that customers with the financial means to do so increasingly install distributed generation, which reduces the revenue base over which fixed network costs are recovered and shifts a larger share of those costs onto remaining grid-dependent consumers. The evidence in this Outlook, including the substantial distributed solar capacity that sits outside official statistics in several markets, is consistent with this pattern.

It is therefore appropriate to consider expenditure on electricity networks within a longer frame of reference. Spending on the grid today is, in part, a strategic investment in the capacity of a country's electricity system to serve demand over the next thirty years, rather than solely the cost of present consumption. Tariff policy that maintains affordability while progressively restoring cost-reflectivity is the principal instrument through which governments can keep that investment financeable, and the balance struck between these two objectives will shape the pace at which each system can modernise.

7 · Grids — Physical State & the Bottleneck

IN BRIEF - Losses run from ~6% (Vietnam, Indonesia) to ~18% (Pakistan) and ~39% ATC&C (Nigeria); over half of Uzbekistan's distribution assets exceed their 30-year service life. - The bottleneck has shifted from generation to evacuation: South Africa's transmission queue, Vietnam's curtailment, India's grid build-out. - Ageing networks cap how much new clean capacity the system can physically absorb — the link between §7 (investment) and the transition's real pace.

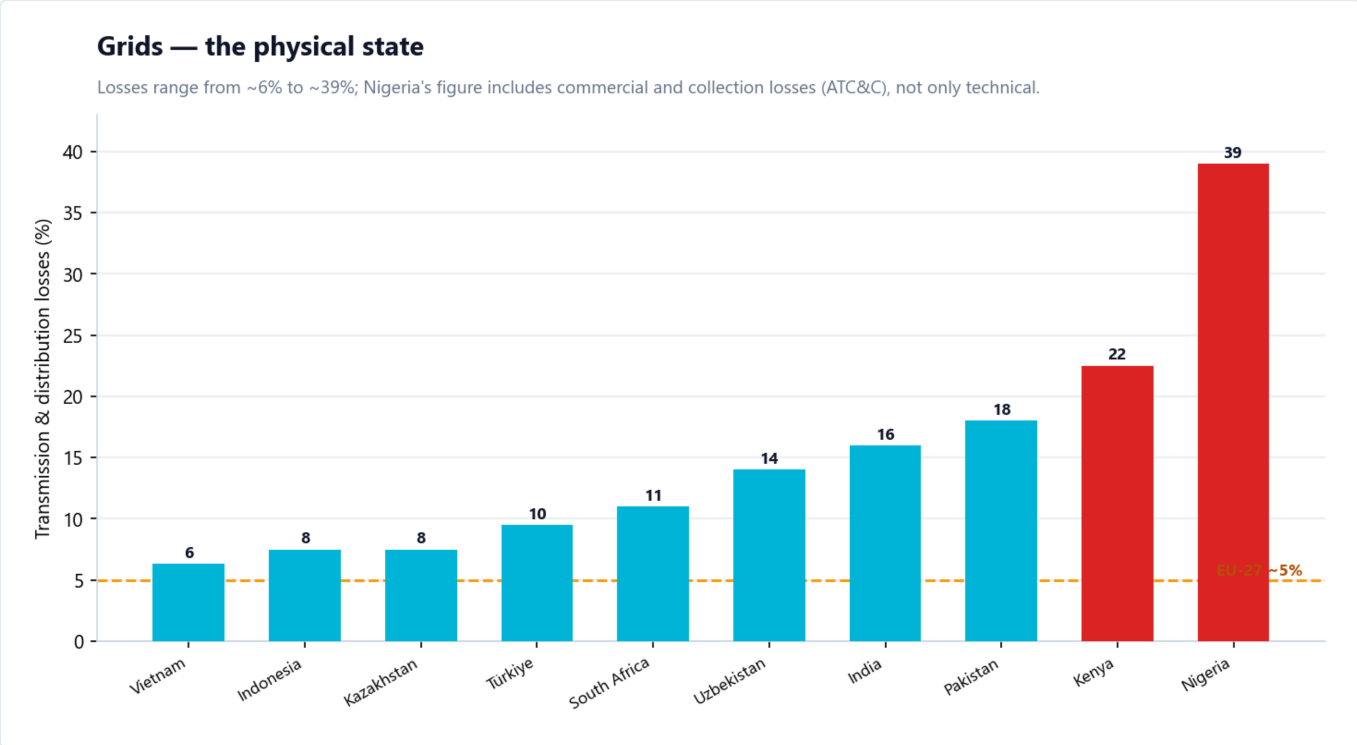


Figure §7 — Transmission and distribution losses; Nigeria's figure includes commercial and collection losses (ATC&C).

Across the ten economies surveyed, the physical condition of the transmission and distribution network varies more widely than any other indicator in this report, and that variation increasingly defines the practical limit on how quickly each system can decarbonise. Measured against an EU-27 benchmark of roughly five percent, technical losses remain comparatively contained in Vietnam at around six percent and in Indonesia at approximately seven and a half percent, while Kazakhstan reports system losses near seven to eight percent, with higher figures in particular regional networks. Türkiye stands at about nine and a half percent and South Africa at around eleven percent. Beyond this band the figures begin to reflect commercial as well as physical factors. Uzbekistan records transmission-and-distribution losses of roughly thirteen to fifteen percent, India reports aggregate technical and commercial losses of about sixteen percent, and Pakistan stands near eighteen percent. Nigeria's aggregate technical, commercial and collection losses approach thirty-nine percent, a figure that incorporates unbilled consumption and uncollected revenue alongside purely technical dissipation, and which therefore should not be read as a measure of network engineering alone.

The condition of the assets themselves compounds these figures. In Uzbekistan more than half of the distribution network is reported to have passed its thirty-year design life, and comparable concerns over ageing plant appear elsewhere in the group, where a substantial share of installed equipment is approaching or beyond its intended service period. Networks of this age carry higher technical losses, require more frequent intervention, and offer less headroom to accommodate new connections without reinforcement.

A common pattern is that the binding constraint on the energy transition is shifting from the capacity to generate electricity toward the capacity to evacuate and absorb it. In South Africa, a substantial queue of projects awaits transmission access, with available grid capacity rather than available generation now setting the pace of new connections. In Vietnam, periods of solar and wind curtailment have followed the rapid addition of variable capacity ahead of the corresponding network reinforcement. In India, a large programme of transmission build-out is underway specifically to connect new renewable capacity in resource-rich regions to centres of demand. In each case the limiting factor lies in the wires and substations rather than in the power stations.

The implication is that the physical state of the network establishes a ceiling on the volume of new clean capacity a system can usefully absorb, irrespective of how much generation is financed or commissioned. Where losses are high, assets are ageing, and connection queues are lengthening, additional renewable capacity cannot be integrated until the network itself is reinforced and modernised. This places the condition of the grid at the centre of the transition rather than at its periphery, and it leads directly to the scale of capital that network renewal and expansion will require, which the following section examines.

8 · The Grid Investment Need — Developing World vs EU-27

IN BRIEF - Global grid investment must roughly double to **~$600 bn/yr by 2030** (from ~$300 bn; IEA 2023, net-zero scenario). - The **EU-27 alone plans €58–75 bn/yr** (€584 bn 2020–30 → €1.2 tn 2024–40) — a benchmark of what a built-out grid costs. - Developing-world programmes are a fraction of need: India ~$20–25 bn/yr, South Africa ~$2.4 bn/yr transmission, Kenya ~$0.25 bn/yr — while the highest-WACC markets face the steepest per-MW cost to close the gap.

Figure §8 — Grid investment: global need, the EU-27 plan, and the ten developing economies' announced programmes.

Global grid investment must approximately double over the remainder of this decade. The International Energy Agency estimated in 2023 that, under a pathway consistent with net-zero objectives, worldwide investment in electricity grids would need to rise to around USD 600 billion per year by 2030, compared with roughly USD 300 billion at the time of the assessment. It is important to read this figure as a requirement under a specific scenario rather than as a record of realised spending; it describes the level of investment that the net-zero-aligned pathway implies, not the level currently being delivered.

The European Union of twenty-seven member states, considered here on its own and excluding the United Kingdom, has set out grid investment plans of a comparable order of magnitude when measured against this global requirement. Under the Action Plan for Grids, the EU-27 envisages on the order of EUR 584 billion across the period from 2020 to 2030, while the subsequent Grids Package points to approximately EUR 1.2 trillion across 2024 to 2040. Expressed on an annual basis, these two reference points together imply a planned commitment in the region of EUR 58 to 75 billion per year. That a single bloc of advanced economies anticipates outlays of this scale provides a useful frame of reference against which the programmes of the developing world can be considered.

The programmes announced across developing economies represent only a fraction of the corresponding need, and the individual figures must be read with care because they differ in scope, with some covering transmission alone, some distribution alone, and others a wider span of the power sector. Presented at face value and with their respective definitions, India's grid investment is estimated by Moody's at approximately USD 20 to 25 billion per year for transmission and distribution combined; the national transmission plan of around INR 9 trillion is a separate, transmission-only figure equivalent to roughly USD 11 to 12 billion per year. South Africa's transmission programme, set out in Eskom's plan of approximately ZAR 440 billion and some 14,000 kilometres of new lines, corresponds to about USD 2.4 billion per year, while Indonesia's transmission investment is of a similar order at around USD 2.4 billion per year. Vietnam's grid investment is estimated at approximately USD 15 billion to 2030. In Türkiye, distribution investment under the fifth tariff period of the regulator stands at around USD 3.8 billion per year, while Pakistan's transmission investment is of the order of USD 0.9 billion per year and Uzbekistan's annual grid spending is in the range of USD 0.5 to 1 billion. Nigeria's frequently cited figure of approximately USD 6.4 billion per year, drawn from a programme of around USD 32 billion, requires a particular caveat, as it covers the entire power value chain, including generation and gas, rather than the grid alone, and should not be compared directly with the transmission or distribution figures cited for the other economies.

These comparisons understate the true distance between requirement and provision in one further respect. Because the cost of capital is structurally higher in most of these markets, a matter examined in the following section, the same physical grid asset costs more per unit to finance and therefore to build than it would in an advanced economy. The headline investment figures, expressed in current dollars, consequently flatter the developing world's position, and the underlying gap between what is planned and what is needed is somewhat wider than those figures alone would indicate.

9 · The Cost of Capital — The Real Barrier

IN BRIEF - Utility-scale solar WACC: developing **8–13.5%** vs advanced **5–6.5%** — a ~2–3× gap (IEA Cost of Capital Observatory). - Driver is sovereign/off-taker risk: only 3 of 10 investment grade; Kazakhstan (Baa1) the exception that finances near-advanced terms. - Blended finance and JETPs (South Africa ~$13 bn, Indonesia $20 bn, Vietnam $15.5 bn) exist to buy down the gap — but disbursement lags ambition.

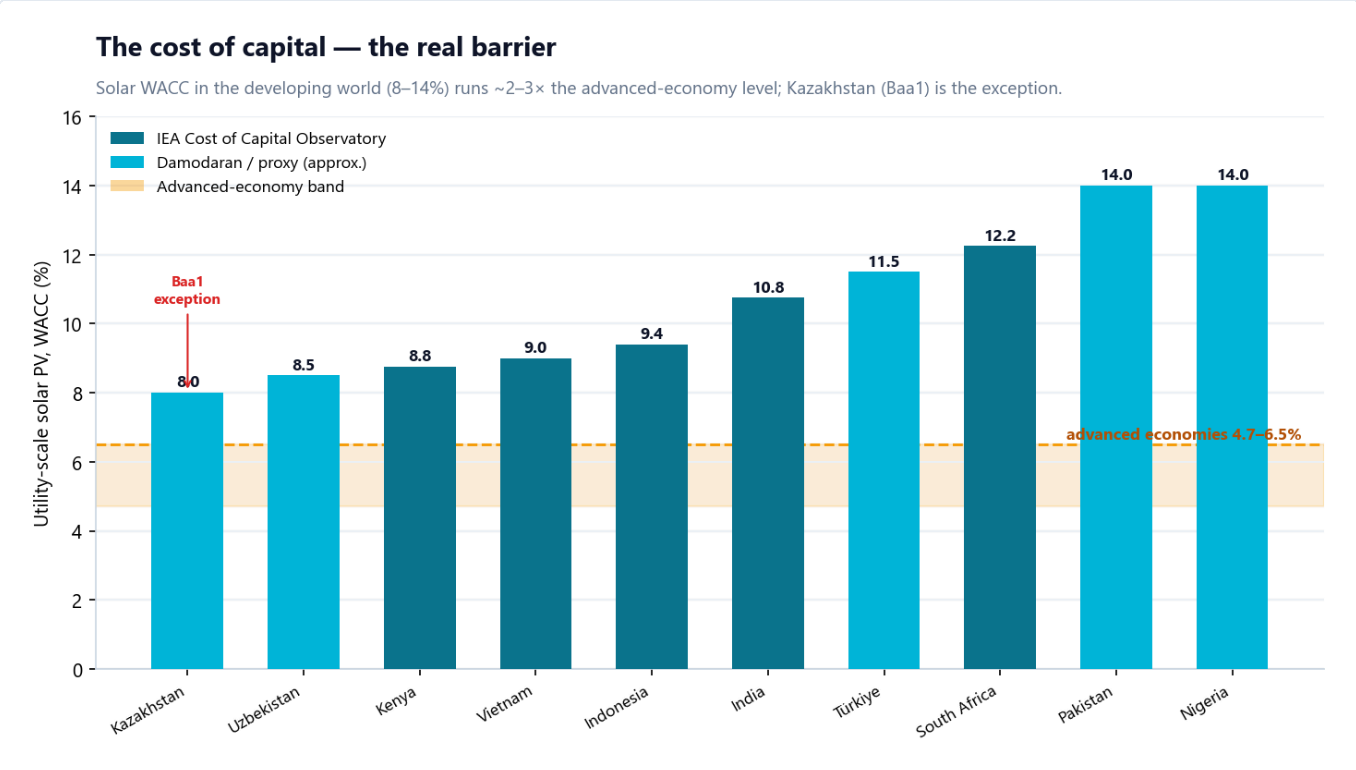


Figure §9 — Utility-scale solar cost of capital: the developing world against the advanced-economy band.

Across the ten emerging markets examined in this report, utility-scale solar is financed at a weighted average cost of capital of approximately 8 to 13.5 percent, compared with roughly 5 to 6.5 percent in Western Europe and North America. The difference of approximately two to three times is consistent with the International Energy Agency's Cost of Capital Observatory, which reports financing costs in emerging and developing economies at least twice the level observed in advanced economies. Among the markets covered by the Observatory, the values are approximately 10 to 11.5 percent in India, 9.4 percent in Indonesia, 9.0 percent in Vietnam, approximately 11 to 13.5 percent in South Africa, and approximately 8.5 to 9 percent in Kenya. Several of the economies discussed in this report — namely Türkiye, Uzbekistan, Kazakhstan, Pakistan and Nigeria — are not presently covered by the Observatory; for these, estimates derived from published country-risk-premium data indicate a comparable or higher range, and they are presented here as approximate rather than as directly measured figures.

The principal driver of this differential is the combination of sovereign and off-taker risk. Of the ten markets, only three — Kazakhstan, India and Indonesia — currently hold an investment-grade sovereign rating, while the remaining seven carry a sovereign risk premium that is transmitted, through the borrowing costs of state utilities and the perceived reliability of long-term power-purchase obligations, into the financing terms available to generation projects. The position of Kazakhstan is instructive in this respect. Rated Baa1, Kazakhstan finances utility-scale solar on terms estimated at approximately 7 to 9 percent, closer to those prevailing in advanced economies than to those of its regional peers. This observation indicates that the determining factor is creditworthiness rather than geography or resource quality, and it is presented here as a measured point of comparison rather than as a contrast intended to single out any individual market.

The consequence of an elevated cost of capital is both direct and cumulative. Because the economics of solar generation and of network expansion are dominated by upfront capital expenditure, a higher discount rate raises the levelised cost of every megawatt of installed capacity and of every kilometre of transmission and distribution network. The effect therefore compounds the grid-investment gap described in the preceding section, since the same physical infrastructure must be financed at a materially higher cost than in advanced economies, and the resources available to close the gap are correspondingly diminished.

Several financing instruments have been designed to narrow this differential. Blended-finance structures, which combine concessional public capital with commercial funding in order to lower the effective cost to the borrower, are increasingly applied to renewable and network projects across these markets. At the sovereign level, the Just Energy Transition Partnerships represent the most prominent attempt to mobilise capital on improved terms, with pledges of approximately USD 13 billion for South Africa, USD 20 billion for Indonesia and USD 15.5 billion for Vietnam. It should be noted, in neutral terms, that the disbursement of these commitments has to date lagged behind the sums pledged, and that the headline figures consequently overstate the capital deployed thus far. The evidence reviewed in this section accordingly indicates that the cost of capital, rather than the availability of resource or technology, constitutes the central constraint on the energy transition in the markets under study, and that addressing it will depend principally on improvements in sovereign and off-taker creditworthiness alongside the continued, and more fully disbursed, use of concessional instruments.

10 · Benchmark — Developing World vs EU-27 / OECD

IN BRIEF - On per-capita consumption, renewables-of-generation, carbon intensity, losses and tariffs, the developing set sits well below EU-27/OECD on welfare metrics and above on inefficiency metrics. - The convergence path is decades long and capital-intensive; the benchmark is not a forecast but a measure of distance to travel. - Two-speed reading: a few (Kazakhstan, Türkiye) approach OECD on some metrics; most (Nigeria, Pakistan, Kenya) are a generation behind.

The comparison in this section draws on the figures presented in the snapshot table and in Figures §3, §4, §6, §7 and §9.

Set against the European Union and OECD benchmarks, the developing set considered in this report sits consistently below the reference economies on the welfare and development metrics, and generally above them on the efficiency and emissions metrics. The first contrast is most visible in electricity use per person. Per-capita consumption across the ten economies ranges from approximately 150 kWh in Nigeria and 190 kWh in Kenya, through roughly 636 kWh in Pakistan and 1,300 to 1,400 kWh in India and Indonesia, to around 6,000 kWh in Kazakhstan, against an EU-27 figure of approximately 6,000 kWh gross and an OECD figure of approximately 7,500 kWh. A comparable distance applies to income: per-capita GDP in the group runs from roughly 835 dollars in Nigeria to about 15,470 dollars in Türkiye, while the EU-27 average stands near 43,150 dollars and the OECD average near 48,300 dollars. The two welfare measures move broadly together, which is consistent with the established association between electricity use and the level of economic development.

On the efficiency and emissions metrics the ordering reverses. Transmission and distribution losses in the benchmark systems are approximately 5 percent for the EU-27 and 6 to 7 percent for the OECD, whereas the developing set generally records higher figures, ranging from roughly 6 to 9 percent in the better-performing systems to about 18 percent in Pakistan and 22 to 23 percent in Kenya. Carbon intensity follows a similar pattern: the EU-27 averages approximately 213 gCO_2/kWh, and several economies in the group, including India at 708, Vietnam at 681 and South Africa in the 673 to 850 range, sit well above that level, reflecting the weight of coal and gas in their generation mixes. Kenya, at approximately 112 gCO_2/kWh on the strength of its geothermal base, is an instance in which a developing system records a lower carbon intensity than the European benchmark.

These comparisons are presented as a measure of the distance to be travelled rather than as a forecast. The gap between current values and the benchmark indicates the scale of consumption growth, network investment and capital that convergence would require, and the histories of the reference economies suggest that such convergence is measured in decades rather than years, particularly given the higher cost of capital documented elsewhere in this report.

Within the group the figures support a measured two-speed reading. A small number of economies approach OECD or EU levels on certain metrics: Kazakhstan reaches roughly 6,000 kWh per person, comparable to the EU-27, and Türkiye combines the highest per-capita income in the set with relatively contained network losses. Most of the others remain a generation behind on one or more measures, with Nigeria, Pakistan and Kenya among those furthest from the benchmark on per-capita consumption, access or losses. The intention here is not to rank the economies as stronger or weaker, since each operates under distinct resource endowments, demographic conditions and stages of system development, but to let the figures express the differences and to record the considerable distance that separates much of the developing set from the reference economies.

11 · Outlook to 2030 / 2035

IN BRIEF - Demand growth concentrates here (India, Vietnam, Indonesia high single-digit CAGR; Türkiye/Central Asia moderate). - The decisive variables are financing cost and grid build-out, not generation ambition — both modelled, neither guaranteed. - Demand is projected to grow materially across the group; the realised pace will depend on the cost of finance and the speed of grid construction, and where official targets are ambitious relative to past delivery, both the target and the implementation risk are noted.

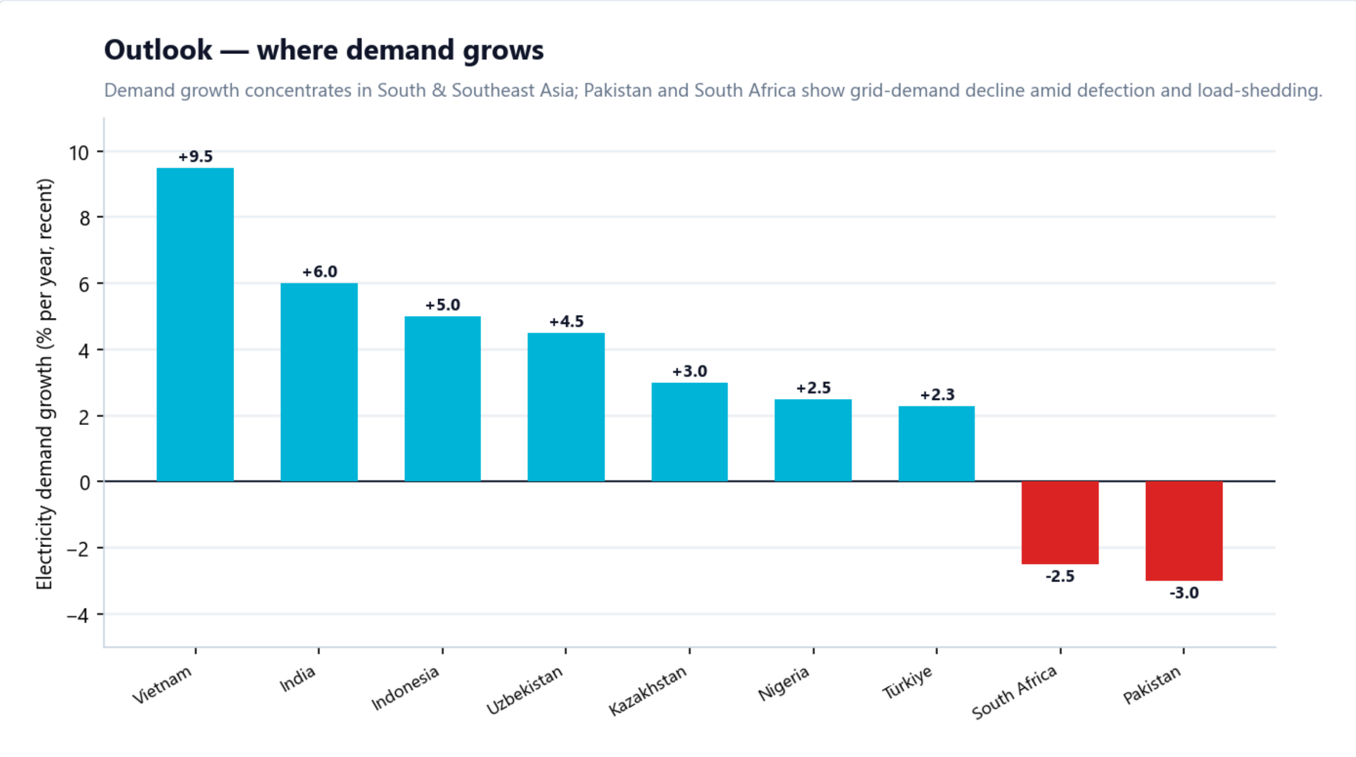


Figure §11 — Recent electricity demand growth by country; the South & Southeast Asian economies lead.

Demand growth over the period to 2030 and 2035 will remain concentrated in this group of economies, although its pace will differ markedly across them. On the basis of the consumption trajectories observed in recent years, Vietnam has sustained the highest demand growth, in the high single digits, while India has expanded at approximately six percent and Indonesia at around five percent annually. Uzbekistan has grown at roughly four-and-a-half percent, reflecting both rising household consumption and the electrification of previously suppressed demand, whereas Türkiye, as a more mature system, has expanded more moderately at around two to two-and-a-half percent. These rates imply that the incremental load added by the faster-growing members of the group over the period will be substantial in absolute terms, and that the burden of new capacity, network reinforcement and system operation will fall most heavily on the economies least able to finance it cheaply.

The principal announced capacity programmes are correspondingly ambitious. Uzbekistan has set out approximately 6.7 GW of additions for 2026 and has raised its 2030 renewables target toward 54 percent of installed capacity. India maintains its target of 500 GW of non-fossil capacity by 2030, which would represent one of the largest clean-capacity build-outs in the world. Vietnam's eighth Power Development Plan envisages a generation fleet approaching 150 GW by 2030, with a pronounced expansion of renewables and a continued, if contested, role for coal and gas. Indonesia's electricity supply business plan, the RUPTL, similarly anticipates a large increase in installed capacity with a growing renewable component. In South Africa, the binding priority is less the addition of generation than the expansion of transmission, where the published development plan foresees a significant programme of new lines required to connect renewable resources and relieve grid congestion.

The decisive variables for the period are not, in the main, the level of generation ambition, which is documented and in several cases legally adopted, but rather the cost of finance and the pace of grid construction. Both remain uncertain. The cost of capital in most of these economies is materially higher than in advanced markets, and a sustained tightening or easing of that cost will shift the realised pace of investment more than any revision to a headline capacity target. The rate at which transmission and distribution networks can be planned, permitted, financed and built is, on present evidence, the most common constraint on delivery across the group, and it is the variable least amenable to rapid change.

Several of the official targets are ambitious relative to the historical pace of delivery. India's 500 GW objective, Vietnam's path toward 150 GW and Uzbekistan's renewables share for 2030 each imply rates of capacity addition and network connection above those achieved in the preceding period. The targets are recorded here as stated by the respective authorities; alongside each, an implementation risk exists where past delivery has lagged formal planning, and this gap between announced intent and demonstrated execution is itself a material consideration for any assessment of the period.

On balance, the outlook to 2030 and 2035 is one of strong and broadly resilient underlying demand across the group, supported by extensive and in several cases legally binding capacity programmes, but conditioned by two persistent constraints: the relatively high and uncertain cost of finance, and the limited pace at which networks can be expanded. The direction of travel is clear, while the rate of progress will depend less on stated ambition than on the resolution of these two conditions over the coming decade.

12 · Analysis

IN BRIEF - The transition in the developing world is constrained on the demand side by affordability, on the supply side by capital, and in the middle by the grid. - Closing the WACC gap (credit reform + blended finance) and accelerating grid investment are the two highest-leverage moves. - The countries that solve cost-of-capital and tariff viability first will leapfrog; the rest risk a slower, costlier, coal-extended path.

The threads developed across this report converge on a single structural observation: the energy transition in these economies is constrained on three fronts that do not operate in isolation but interact, each amplifying the others. On the demand side, the binding constraint is affordability and tariff viability. Residential tariffs across the sample range widely, and where they remain below cost-recovery levels the financial health of the distribution segment is compromised, which in turn limits the capital available for reinvestment. On the supply side, the binding constraint is the cost of capital. The evidence assembled here, consistent with the IEA's own assessment, indicates that the weighted average cost of capital for utility-scale solar in the developing economies of this sample stands at roughly two to three times the level prevailing in advanced economies, where it sits in the region of five to six and a half percent against eight to thirteen and a half percent in much of the developing world. Because the capital cost of renewable and network assets is overwhelmingly upfront, this differential raises the delivered cost of every megawatt financed, independent of the underlying engineering. Connecting these two fronts is the third constraint: the physical and financial state of the grid. Transmission and distribution losses across the sample frequently exceed levels seen in advanced systems, ageing assets are widespread, and in several economies the binding bottleneck is no longer generation capacity but the network's ability to absorb and deliver it.

From this structure follows an assessment of where intervention carries the greatest leverage. Two priorities stand out, and they are not independent. The first is narrowing the cost-of-capital gap, achieved through credit reform that improves sovereign and utility standing, through the strengthening of off-takers so that power-purchase obligations are bankable, and through the disciplined use of blended finance to absorb the risks that private capital will not price on its own. The second is accelerating investment in networks, where the funding requirement is substantial and, on current trajectories, under-met. These two priorities are mutually reinforcing in a specific and important sense: because the grid build-out is itself a capital-intensive, long-duration undertaking, a lower cost of capital directly reduces the price of constructing it. Progress on the financing front therefore lowers the cost of progress on the physical front, and a more capable, less loss-prone grid improves the revenue base that underpins creditworthiness in turn.

It is appropriate to frame investment in electricity networks in terms commensurate with its horizon. A transmission or distribution asset commissioned today will define the reliability, the cost, and the carbon intensity of a country's power system across the next three decades. Expenditure of this kind is therefore better understood as a strategic commitment to the coming generation than as a line of current spending, and the security of supply it underwrites carries both national and, through increasingly interconnected systems and shared supply chains, international dimensions.

The outlook that follows from this analysis is differentiated rather than uniform, and it is offered as assessment rather than as judgement of any individual economy. Those economies that resolve the cost-of-capital and tariff-viability questions earlier — whether through investment-grade standing, credible regulatory frameworks, or cost-reflective pricing introduced with appropriate protection for vulnerable consumers — are positioned to progress more rapidly and at lower cost. Those that defer these resolutions face a slower and more expensive path, in which high financing costs and constrained networks compound one another. The distinction is not one of ambition but of sequencing, and the years immediately ahead will be decisive in determining which economies move from intention to durable delivery.

Country Profiles

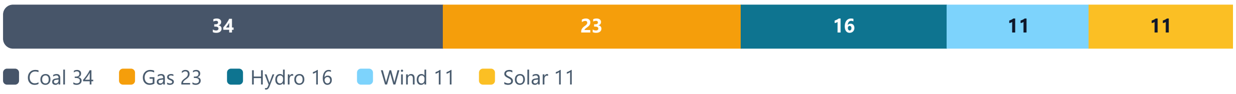
Each profile presents the headline indicators followed by a brief, neutral assessment of the country's current position. Figures are drawn from the data concept and carry the cautions noted there.

Türkiye

large upper-middle-income system, the group's most liberalised market

85.5 mn Population	**~$15,470** GDP/capita	**122.5 GW** Capacity	**~363 TWh** Generation
~3,900 kWh Per-capita	**100%** Access	**BB-/Ba3/BB-** Rating	

GENERATION MIX



T&D losses ~9.5% · Residential tariff ~6.0 ¢/kWh · Solar WACC not in the IEA Observatory (country risk premium ~4.7%) · Carbon ~395 gCO_2/kWh · Net-zero 2053.

ASSESSMENT

- Türkiye combines the highest per-capita income in the group with a fully unbundled, exchange-based market, and has recently become a marginal net exporter of electricity.
- A renewable roadmap targeting 120 GW of wind and solar by 2035 and the commissioning of the Akkuyu nuclear plant are the principal structural developments under way.
- The cost of capital remains higher than in advanced economies, and a multi-year World Bank grid programme indicates the scale of network investment required to support continued renewable additions.

Uzbekistan

gas-based system in rapid reform and renewables scale-up

~38 mn Population	**~$3,850** GDP/capita	**27.3 GW** Capacity	**81.5 TWh** Generation
~2,200 kWh Per-capita	**100%** Access	**BB/Ba3/BB** Rating	

GENERATION MIX

Gas 76 Coal 11 Hydro 9

T&D losses ~13–15% | Residential tariff ~4.8 ¢/kWh | Solar WACC ~8–9% (estimate; not in the Observatory)

Carbon 473 gCO_2/kWh (2023) | Net-zero 2050.

ASSESSMENT

- Uzbekistan is moving from a vertically integrated state model toward a single-buyer structure, with an independent regulator established in 2023 and the single-buyer function operational since mid-2024.
- Gulf-backed independent power producers are scaling solar and wind quickly, supporting a 2030 renewables target raised toward 54% of capacity.
- More than half of the distribution network is reported to be beyond its thirty-year service life, and a modernisation programme of around $3–4 billion to 2030, supported by multilateral lenders, is directed at losses and reliability.

Kazakhstan

coal-based system; the only Baa1-rated sovereign in the group

20.3 mn Population	**~$14,000** GDP/capita	**25.3 GW** Capacity	**~118 TWh** Generation
~6,000 kWh Per-capita	**100%** Access	**BBB-/Baa1/BBB** Rating	

GENERATION MIX

Coal 54 Gas 28 Hydro 8 Wind And Solar 5

T&D losses ~7–8% | Residential tariff ~6.3 ¢/kWh | Solar WACC ~7–9% (Baa1) | Carbon ~600 gCO_2/kWh (estimate) | Net-zero 2060.

ASSESSMENT

- Kazakhstan records both the highest per-capita consumption and the highest per-capita carbon dioxide emissions in the group, reflecting an energy-intensive, coal-based economy.
- Its Baa1 rating allows financing on terms closer to advanced economies, and it is conducting renewable auctions alongside a "tariff in exchange for investment" programme to renew ageing assets.
- A 2024 referendum approved construction of the country's first nuclear plant, to be led by an international consortium, adding a significant element to long-term system planning.

India

the group's largest system and a principal driver of global demand growth

~1,463 mn	Population
~$2,820	GDP/capita
513.7 GW	Capacity
~1,840 TWh	Generation
~1,395 kWh	Per-capita
99.5%	Access
BBB-/Baa3/BBB-	Rating

GENERATION MIX

Coal 70 · Solar 9 · Hydro 8 · Wind 5 · Nuclear 3

AT&C losses ~16% · Residential tariff ~7.4 ¢/kWh · Solar WACC ~10–11.5% (IEA) · Carbon 708 gCO_2/kWh · Net-zero 2070.

ASSESSMENT

- India reached its target of 50% non-fossil installed capacity around 2025, ahead of schedule, while coal continues to provide roughly 70% of generation.
- The binding constraint is increasingly the network: a transmission build-out of around ₹9 trillion to 2032 is intended to connect new renewable capacity, and distribution-company finances remain the principal weakness.
- Off-taker risk at the distribution level is the central factor keeping the cost of capital well above advanced-economy levels and shaping project economics.

Pakistan

system marked by grid-demand stagnation and a large distributed-solar shift

~250 mn Population	**~$1,485** GDP/capita	**~45.9 GW** Capacity (grid)	**~137 TWh** Generation
~636 kWh Per-capita	**95.6%** Access	**B-/Caa1/B-** Rating	

GENERATION MIX

Hydro 25 · Solar 25 · Gas 20 · Coal 15 · Nuclear 15

T&D losses ~18% · Residential tariff ~11.2 ¢/kWh · Solar WACC ~12–16% (derived) · Carbon ~245 gCO_2/kWh · Net-zero: none announced.

ASSESSMENT

- Grid electricity demand has declined for several consecutive years, while behind-the-meter rooftop solar has expanded substantially, with official net-metering near 6.8 GW and independent estimates of total distributed capacity of 27–33 GW.
- High tariffs and circular debt of around PKR 1.6 trillion have prompted both customer migration to distributed generation and cost-recovery reforms conditioned by the country's IMF programme.
- Pakistan has not announced a formal net-zero target; its 2025 NDC sets a conditional reduction against projected 2035 emissions.

Indonesia

large coal-based, single-buyer system with a major transition partnership

~283 mn Population	**~$4,925** GDP/capita	**100.6 GW** Capacity	**371.6 TWh** Generation
~1,300 kWh Per-capita	**99.4%** Access	**BBB/Baa2/BBB** Rating	

GENERATION MIX

Coal 67 · Gas 15 · Hydro 7 · Geothermal 5 · Solar And Wind 0

T&D losses ~7.5% · Residential tariff ~9.9 ¢/kWh · Solar WACC 9.4% (IEA) · Carbon ~610 gCO_2/kWh · Net-zero 2060.

ASSESSMENT

- The state utility operates as a vertically integrated single buyer, and renewables remain a small share of generation despite an investment-grade rating that lowers financing costs relative to most peers.
- The $20 billion Just Energy Transition Partnership targets a power-sector emissions cap, though disbursement has been limited and the latest supply plan retains substantial coal and gas.
- Captive coal capacity serving industrial estates and metal smelters, largely outside the grid, is a significant element of the country's emissions trajectory.

Vietnam

fast-growing system; a notable case of rapid renewables addition ahead of the grid

~101 mn
Population

~$4,700
GDP/capita

82.4 GW
Capacity

~308 TWh
Generation

~2,650 kWh
Per-capita

~100%
Access

BB+/Ba2/BB+
Rating

GENERATION MIX

Coal 49 · Hydro 32 · Solar And Wind 13 · Gas 7

T&D losses ~6.3% · Residential tariff ~8.6 ¢/kWh · Solar WACC 9.0% (IEA) · Carbon 681 gCO_2/kWh · Net-zero 2050.

ASSESSMENT

- A rapid solar and wind build-out between 2019 and 2021 outpaced the network, producing curtailment in southern-central provinces and unresolved questions over retroactive tariff terms.
- The eighth Power Development Plan targets a generation fleet near 150 GW by 2030, and a direct power-purchase mechanism now allows large consumers to contract renewables outside the single buyer.
- The $15.5 billion Just Energy Transition Partnership supports the path toward the 2050 net-zero objective, with grid expansion among the principal constraints.

Nigeria

gas-based grid with a large installed-versus-delivered gap and the group's lowest access

~235 mn	Population
~$835	GDP/capita
~13 GW installed (~4 GW delivered)	Capacity
~35 TWh	Generation
~150 kWh	Per-capita
~57%	Access
B/B3/B	Rating

GENERATION MIX

Gas 70 Hydro 30

AT&C losses ~39% · Residential tariff (Band A) ~15–16 ¢/kWh · Solar WACC ~13–15% (estimate) · Carbon ~400 gCO_2/kWh · Net-zero 2060.

ASSESSMENT

- Installed capacity of around 13 GW delivers only about 4 GW, a gap reflecting gas supply, transmission limits and ageing plant; aggregate technical, commercial and collection losses approach 39%.
- The 2023 Electricity Act decentralised regulation, enabling states to develop their own markets, and the 2024 Band A tariff introduced cost-reflective pricing for higher-service customers.
- Extending access to an estimated 85–95 million people without supply is expected to rely substantially on mini-grids and off-grid solar alongside grid extension.

South Africa

coal-based system in transition, with transmission now the binding constraint

~63 mn
Population

~$6,300
GDP/capita

~58 GW
Capacity

~230 TWh
Generation

~3,200 kWh
Per-capita

87.7%
Access

BB/Ba2/BB-
Rating

GENERATION MIX

Coal 82 · Nuclear 4 · Solar 8 · Wind 5 · Hydro 1

T&D losses ~11% · Residential tariff ~12.0 ¢/kWh · Solar WACC ~11–13.5% (IEA) · Carbon ~673–850 gCO_2/kWh · Net-zero 2050.

ASSESSMENT

- Load-shedding has eased substantially since its 2023 peak, supported by improved plant availability and a marked increase in embedded rooftop solar.
- The unbundling of the state utility has advanced with the establishment of an independent transmission company, and a 14,000 km / R440 billion transmission plan addresses what has become the principal bottleneck for connecting renewables.
- A Just Energy Transition Partnership of around $13 billion supports the move away from coal, which still provides roughly 82% of generation and gives the system the highest carbon intensity in the group.

Kenya

predominantly renewable, geothermal-led system; a low-carbon outlier

~57.5 mn
Population

~$2,206
GDP/capita

3.2 GW
Capacity

~12 TWh
Generation

~190 kWh
Per-capita

~76%
Access

B/B3/B-
Rating

GENERATION MIX

Geothermal 40 · Hydro 26 · Wind 13 · Imports 10 · Thermal 7 · Solar 3

T&D losses ~22–23% · Residential tariff ~22 ¢/kWh · Solar WACC ~8.5–9% (IEA) · Carbon ~112 gCO_2/kWh · Net-zero ~2050 (aspirational).

ASSESSMENT

- Kenya draws around 83% of its electricity from geothermal and hydropower, giving it the lowest carbon intensity in the group, below the EU-27 benchmark.
- Access of around 76% is being extended through the Last Mile Connectivity programme and a base of approximately 1.2 million solar home systems and mini-grids.
- The utility faces financial pressure from legacy thermal power-purchase agreements and elevated network losses, while the transmission operator relies increasingly on public-private partnerships to fund expansion.

Annex A — Abbreviations

AT&C aggregate technical and commercial (losses) · **ATC&C** aggregate technical, commercial and collection (losses) · **BESS** battery energy storage system · **DARES** Distributed Access through Renewable Energy Scale-up (Nigeria) · **CAGR** compound annual growth rate · **DPPA** direct power purchase agreement · **EU-27** European Union (27 member states) · **GW / MW** gigawatt / megawatt · **gCO_2/kWh** grammes of carbon dioxide per kilowatt-hour · **IEA** International Energy Agency · **IMF** International Monetary Fund · **IPP** independent power producer · **JETP** Just Energy Transition Partnership · **kWh / TWh** kilowatt-hour / terawatt-hour · **NDC** nationally determined contribution · **OECD** Organisation for Economic Co-operation and Development · **PDP8** Vietnam's eighth Power Development Plan · **PPA** power purchase agreement · **RE** renewable energy · **RUPTL** Indonesia's electricity supply business plan · **T&D** transmission and distribution · **TSO** transmission system operator · **VAT** value-added tax · **WACC** weighted average cost of capital.

National institutions referenced: EPDK (Türkiye regulator), EMDRA (Uzbekistan regulator), KEGOC (Kazakhstan system operator), CEA (India Central Electricity Authority), NEPRA / NTDC (Pakistan regulator / transmission), PLN (Indonesia utility), EVN (Vietnam utility), NERC / TCN (Nigeria regulator / transmission), Eskom / NERSA / NTCSA (South Africa utility / regulator / transmission), EPRA / KPLC / KETRACO (Kenya regulator / utility / transmission).

Annex B — Sources (section-by-section)

Cross-cutting data foundation: Ember (Yearly Electricity Data; Global Electricity Review 2025/2026); Our World in Data; World Bank (World Development Indicators); IMF (World Economic Outlook); UN (World Population Prospects); IRENA; IEA (Cost of Capital Observatory; *Electricity Grids and Secure Energy Transitions*, 2023; country profiles — CC BY); A. Damodaran (country risk premiums, NYU Stern); S&P Global, Moody's, Fitch (sovereign ratings); national regulators and utilities listed in Annex A.

- **§1 Snapshot / §3 Demand & Development —** World Bank (population, GDP per capita, electricity access); Ember and Our World in Data (per-capita consumption); Enerdata (primary energy); national statistical offices.
- **§4 Generation Mix —** Ember and lowcarbonpower (mix and carbon intensity); national utilities and authorities (CEA, PLN, EVN, KEGOC, Eskom, EPRA, Uzbekistan Ministry of Energy); EEA (EU-27 carbon intensity).
- **§5 Access & the Last Mile —** World Bank / SE4ALL; IEA; national energy compacts (Kenya, Nigeria); off-grid programme documentation.
- **§6 Tariffs, Subsidies & Viability —** GlobalPetrolPrices; national regulators (EPDK, NEPRA, NERC, EPRA, PLN); Eurostat (EU-27 prices); NEPRA / State Bank (Pakistan circular debt); IMF programme documentation.
- **§7 Grids — Physical State —** World Bank (loss indicators); national utilities and regulators; ADB and World Bank project documentation (Uzbekistan, Pakistan).
- **§8 Grid Investment Need —** IEA (*Electricity Grids and Secure Energy Transitions*, 2023); European Commission (Action Plan for Grids, 2023; Grids Package, 2025); Moody's (India); Eskom (transmission plan); PDP8 and RUPTL; EPDK (fifth tariff period); NTDC (Pakistan); KETRACO (Kenya).
- **§9 Cost of Capital —** IEA Cost of Capital Observatory; A. Damodaran (country risk premiums); sovereign rating agencies; JETP partnership documents (South Africa, Indonesia, Vietnam).
- **§10 Benchmark —** Eurostat; Ember European Electricity Review 2025; IEA Electricity Information (OECD aggregates); World Bank.
- **§11 Outlook —** national capacity plans (India 500 GW / CEA; Vietnam PDP8; Indonesia RUPTL; Uzbekistan Ministry of Energy; South Africa transmission plan); IMF World Economic Outlook; Enerdata (historical growth).
- **Climate indicators (mix, profiles) —** Ember; EEA; Climate Action Tracker; UNFCCC (nationally determined contributions); Net Zero Tracker.

Figures marked [teyit] in the underlying data concept rely on secondary sources or estimates and warrant primary-source confirmation before any individual figure is cited in isolation. Full per-entity data and verification record: data concept (emerging-energy-outlook-veri).

Annex C — Methodology & Data Vintage

- **Two-speed cut:** structural data ≈ 2024–2025; tariffs latest in-force (dated per row).
- **Tariffs** normalized to VAT-inclusive USc/kWh; FX dates stated (note: TRY ~46.4/USD mid-2026).
- **Per-capita consumption** given with EU-27 (~6,000) + OECD (~7,500) context; gross/final basis stated.
- **WACC:** IEA Cost of Capital Observatory where covered (IN/ID/VN/ZA/KE); Damodaran/proxy elsewhere (TR/UZ/KZ/PK/NG), marked [teyit].
- **Verification:** Faz ① 11-agent compilation + 3-agent adversarial round (dogrulayici, 2026-06-21) — core 2–3× WACC thesis upheld; 6 corrections applied. Full data concept: emerging-energy-outlook-veri.
- *Data-vintage table (metric × as-of × source) — Faz ②b.*

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