Electricity Infrastructure Primer

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1. Introduction

Electricity infrastructure underpins every sector of the modern economy, from data centres and industrial manufacturing to residential heating and transport. The electricity system is undergoing profound structural change as the global energy transition accelerates via decarbonisation, decentralisation, and digitalisation. For institutional investors, this presents both significant opportunity and complexity.

This primer is intended as an accessible introduction to electricity infrastructure for actuaries and generalist investment professionals, particularly those involved in long-term investing via insurance company or pension fund portfolios (**Long Term Institutional Investors** or **LTIIs**). It seeks to demystify the electricity value chain by clearly outlining how power is generated, transmitted, distributed, and consumed. While the underlying system is complex and often technical, the investment proposition is underpinned by long-lived, tangible assets with regulated or contracted revenue, characteristics which are often aligned with the liability profiles of long-duration institutional investors. This may present opportunities for commercial investments that can have a positive societal impact.

This paper does not aim to provide detailed engineering insights. Rather, it offers a conceptual framework for understanding the electricity system's structure and its implications for the risks and returns of potential investments. We begin with the fundamentals of how electricity flows from source to socket.

2. From generation to consumption: understanding the electricity value chain

The electricity system can be visualised as a value chain comprising four primary segments: generation, transmission, distribution, and consumption. Each plays a critical role in the delivery of reliable power to end users, and each segment offers distinct infrastructure investment opportunities. This section provides a high-level overview of the system's structure and interdependencies.

2.1 Generation: converting primary energy into electricity

Electricity generation is the first stage in the system and refers to the conversion of primary energy sources into electrical energy. The generation mix varies by geography and policy framework, but can be broadly categorised into:

- **Thermal generation**: Includes fossil fuels such as coal, gas, and oil. These plants burn fuel to create steam, which drives turbines. While dispatchable and mature, these assets face increasing policy and carbon pricing risks.
- **Renewable generation**: Includes wind, solar, hydro, and biomass. These are typically capital-intensive upfront but have low operating costs and zero fuel risk. Revenue is often secured through long-term power purchase agreements (**PPA**s) or feed-in tariffs.
- **Nuclear generation**: Offers large-scale, low-carbon baseload power but is subject to long lead times, high capital costs, and public scrutiny.

Generators can be centrally located (e.g. large gas or offshore wind plants) or increasingly distributed (e.g. rooftop solar or local batteries). Electricity is produced as alternating current (**AC**) and, given the lack of cost-effective large-scale storage, must be used in real-time, requiring constant balancing of supply and demand.

Investment characteristics vary significantly depending on technology, market design, and contractual arrangements. Renewable assets have become a focal point for LTIIs due to policy support and the growing importance of net-zero targets.

2.2 Transmission: delivering power over long distances

Electricity generated at power plants must be transported to demand centres, which may be located hundreds of miles away. This is achieved via transmission networks, which operate at high voltage (typically above 110kV) to minimise energy loss over long distances. The transmission system includes:

- **Overhead lines and underground cables**: The primary means of long-distance energy transport.
- **Substations**: Which step up voltage for transmission and step it down for distribution.
- **System operators**: Entities responsible for balancing the grid and maintaining frequency and reliability.

Transmission infrastructure is capital-intensive, with natural monopoly characteristics. In most countries, these assets are owned and operated under a regulated model that provides a fixed return on a regulated asset base (**RAB**). In the United Kingdom (**UK**), for example, National Grid Electricity Transmission operates under a price control framework set by Ofgem.

For investors, transmission assets offer long-duration, inflation-linked cash flows with low exposure to merchant risk. However, they are also subject to regulatory review cycles and capital expenditure scrutiny, which require careful monitoring.

2.3 Distribution: bringing power to the end user

Once electricity reaches local substations, it enters the distribution network. This lower-voltage system (typically below 33kV) delivers power to residential, commercial, and small industrial users. Distribution assets include:

- **Local substations**: Where voltage is stepped down further for end-user delivery.
- **Cables and poles**: Connecting substations to consumers.
- **Metering infrastructure**: Including smart meters that record usage and support dynamic pricing.

Distribution networks are also natural monopolies and typically operate under regulated business models. Like transmission, they provide stable, long-term revenues, though they are increasingly required to accommodate new challenges such as:

- Integration of distributed generation (e.g. solar panels).
- Electric vehicle charging infrastructure.
- Demand-side response and energy efficiency technologies.

From an investment perspective, these evolving dynamics create both opportunity and complexity. New capital investment will be required, while returns will be shaped by regulatory frameworks that increasingly focus on innovation and customer outcomes.

2.4 Consumption: understanding the end-user perspective

The final link in the chain is consumption. End users draw electricity from the distribution network for domestic, commercial, and industrial use. Patterns of consumption are becoming more complex, driven by trends such as:

- Corporate Net Zero and decarbonisation targets.
- Electrification of transport (e.g. electric vehicles).
- Electrification of heat (e.g. heat pumps).

- Smart appliances and energy management systems.
- Prosumers (users who also generate energy).

While end users are not infrastructure in themselves, changes in consumption patterns directly impact system design, regulatory incentives, and investment needs across the value chain. Investors should monitor these trends closely, as they influence both revenue stability and capital requirements of electricity infrastructure assets.

2.5 Grid flexibility

Grid flexibility is a concept which features through this primer. Grid flexibility refers to the electricity system's ability to keep supply and demand balanced, and to maintain stable frequency and voltage, even when generation and demand change quickly (for example when wind output drops or electric vehicle charging increases).

Flexibility can come from flexible supply (fast-start generation, batteries), flexible demand (demand response, smart tariffs), stronger interconnection, or digital control systems that allow the operator to manage congestion and short-term imbalances.

Simple examples of this flexibility include:

- Demand response that pays industrial customers to reduce load during peaks.
- Interconnectors that allow imports/exports to smooth regional mismatches.

3. Deep dive: what does "investing in the grid" mean?

3.1 Importance of the grid to the energy transition

The grid is the backbone of the energy system. In simple terms, without a robust, modern grid, the energy transition cannot succeed, no matter how much renewable energy is built. The need for grid investment is increased by the use of greater amounts of intermittent renewable energy generation and the electrification of more key sectors of industry.

- **Renewables** create new demands on the grid. Unlike traditional fossil-fuel power plants, which are typically large and centrally located, renewable energy sources like wind and solar are often smaller, more variable, and more geographically dispersed. This requires the grid to become more flexible, dynamic, and digitally controlled to manage intermittent generation and maintain stability.
- **Electrification** further increases pressure on the grid. As sectors like transport (e.g., electric vehicles) and heating (e.g., heat pumps) switch from fossil fuels to electricity, overall electricity demand is expected to rise significantly. The grid must be upgraded not just to handle more power, but also to deliver it reliably and efficiently to millions of new consumption points.

Delays in grid investment therefore threaten the entire transition. In many regions, renewable projects are being held up not by a lack of capital or ambition, but by grid connection backlogs and permitting constraints. Without parallel investment in grid infrastructure, renewable capacity will sit idle, and climate goals will remain out of reach.

3.2 Current state of grid infrastructure around the world

Summary table

Stage	Description	Representative countries / regions
1. Basic grid infrastructure	Low access and reliability. Focus on electrification and reducing outages.	Nigeria, Nepal
2. Developing grid	Expanding access and improving capacity. Limited ability to integrate renewables.	India, Indonesia
3. Intermediate grid	Moderate renewable integration, but bottlenecks in transmission and flexibility.	China, United States (nationally, excluding leading states)
4. Advanced grid	High renewable penetration, growing use of smart systems, but facing grid constraints.	Germany, the UK
5. Cutting-edge / smart grid	Fully digital, flexible, and decentralized systems with real-time optimization.	South Korea, California (USA)

3.2.1 Basic grid infrastructure: limited access, fragile reliability

Grids in this stage are typically underdeveloped, have low electrification rates, and suffer from frequent outages. Investment is focused on basic grid extension, rural electrification, and stabilizing supply.

Characteristics include:

- Low voltage distribution networks dominate.
- Minimal grid coverage in rural areas.
- Limited generation diversity and grid interconnection.
- High technical losses and frequent blackouts.

Representative regions include:

- **Sub-Saharan Africa (e.g. Nigeria, Democratic Republic of Congo):** Millions remain without access to electricity. Transmission networks are often outdated, and utilities are financially weak.
- **South Asia (e.g. parts of Bangladesh, Nepal):** Considerable progress has been made on electrification, but the grid remains vulnerable to demand spikes and extreme weather.

3.2.2. Developing grid: expanding coverage, managing load growth

These systems have improved access and reliability but are not yet ready for large-scale integration of variable renewables. Priorities include reducing losses, upgrading capacity, and introducing basic automation.

Characteristics include:

- High transmission losses due to outdated infrastructure.
- Growing electricity demand from urbanization and industry.
- Limited renewable energy penetration due to grid constraints.
- Grid extension and reinforcement projects underway.

Representative regions include:

- **India:** Near-universal access achieved, but grid congestion and coal dominance persist. Large investments underway to support renewables.

- **Indonesia, Vietnam, Philippines:** Fast-growing electricity demand with mixed progress on grid modernization.

3.2.3. Intermediate grid: beginning renewable integration, facing bottlenecks

Grids can handle moderate levels of renewables but struggle with intermittency and congestion. Regulatory and operational reforms are emerging, but physical upgrades lag behind decarbonization goals.

Characteristics include:

- Some grid balancing and forecasting tools used.
- Investment in transmission upgrades and interconnectors is ongoing.
- Renewable penetration in the 20–40% range, with curtailment risks.
- Emerging flexibility markets and demand-side response initiatives.

Representative regions include:

- **United States:** Strong in some states (e.g. California, Texas), but overall national grid is fragmented and aging, with severe transmission permitting challenges.
- **China:** Rapid grid buildout and massive investment, but regional imbalances and curtailment of wind/solar persist.
- **Latin America (e.g. Chile, Brazil):** Strong renewable resources, but transmission lags behind, especially for remote solar/wind sites.

3.2.4. Advanced grid: high renewable penetration, flexibility challenges

Grids in this stage have high renewable shares and growing electrification of transport and heating. The focus is on grid flexibility, cross-border coordination, and digital optimization.

Characteristics include:

- Renewable generation >40–60% of total supply in some regions.
- Increasing reliance on grid-scale storage, demand response, and interconnection.
- Growing use of digital twins, real-time monitoring, and AI-based control systems.
- Grid constraints (e.g. connection delays) increasingly limit new projects.

Representative regions include:

- **Germany, Denmark, Netherlands:** High wind and solar penetration, strong interconnection with neighbours, but grid bottlenecks (especially north-south) remain a constraint.
- **UK:** Leading offshore wind deployment, smart metering, and system operator innovation, but suffering from grid connection delays and investment gaps.
- **Nordics:** Large hydro capacity provides natural balancing, enabling high renewable share and cross-border electricity trade.

3.2.5. Cutting-edge / smart grid: decentralized, resilient, data-driven

Few regions are in this category. Grids are being reimagined as digital platforms that accommodate millions of distributed energy resources (**DER**s), dynamic pricing, and real-time optimization.

Characteristics include:

- Bi-directional flows between producers and consumers (prosumers).
- Integration of EVs, home batteries, smart appliances into the grid.
- Automated grid management with AI, IoT sensors, and predictive analytics.
- Full rollout of smart meters and dynamic tariffs.

Representative regions include:

- **South Korea:** Investing heavily in smart grid technology and pilot cities.
- **Japan:** Advanced demand response and islanded microgrid experiments, driven by energy security needs post-Fukushima.
- **California:** Leading in DER integration, battery storage, and time-of-use pricing, though challenges remain with fire risks and grid resiliency.

3.3 Key barriers to grid investment

Despite broad recognition that electricity grid upgrades are essential for the energy transition, investment in grid infrastructure continues to lag. Several systemic barriers (financial, institutional, and technical) are preventing progress. These barriers are often interrelated and vary by region, but some common themes emerge globally, as discussed below.

3.3.1. Capital allocation and cost recovery challenges

Grid infrastructure is capital-intensive, with long payback periods and often uncertain revenue streams. This makes it less attractive than generation assets (like wind or solar farms), which may benefit from clearer business models and subsidies.

Regulated returns on grid assets are typically modest. Where utilities or transmission system operators are under financial strain, they may underinvest or delay upgrades.

In developing countries, poor creditworthiness of state utilities or lack of access to affordable finance further constrains grid expansion.

3.3.2. Regulatory and policy uncertainty

Grid investments depend heavily on regulatory frameworks. However, in many regions, these are outdated, fragmented, or misaligned with decarbonization goals.

Inflexible rules around cost recovery, connection fees, or who pays for upgrades can stall projects or deter private capital.

Political cycles also create risk. Transmission buildouts often span multiple election periods, leading to shifting priorities and inconsistent follow-through.

3.3.3. Permitting and public opposition

New transmission lines often face long permitting timelines due to land use conflicts, environmental assessments, or local opposition (so-called “not in my backyard” sentiment).

In many cases, it takes 10-15 years to plan and build a major transmission line. This is significantly longer than building new renewables, creating a structural mismatch between generation and grid readiness.

3.3.4. Technical complexity and talent gaps

Operating a modern, flexible grid that can handle large shares of intermittent renewables requires advanced control systems, real-time data management, and deep system modelling expertise.

In many system operators and utilities, there is a shortage of qualified engineers, data scientists, and cybersecurity specialists needed to design and operate next-generation grids.

Technical standards and interoperability (e.g., between digital platforms and legacy hardware) are still evolving, creating integration risks.

3.3.5. Lack of cross-border coordination

Electricity systems often stop at national borders, while renewable resources and demand growth are not so neatly aligned. Without cross-border interconnection and cooperation, grids remain fragmented and inefficient.

Regional planning is especially lacking in Europe (e.g. slow progress on interconnectors) and Southeast Asia, where greater coordination could reduce costs and improve reliability.

Grid operators and energy ministries often work in silos, with limited shared planning between transport, industry, and power sectors.

3.3.6. Competing priorities and short-termism

Governments and utilities are often focused on more visible, politically appealing investments. Examples include subsidising consumer bills, launching flagship generation projects, or reacting to energy price spikes.

Grid infrastructure, by contrast, is invisible to the public until it fails. Its benefits are long-term, diffuse, and harder to communicate.

Climate adaptation, energy security, and affordability concerns are all valid. However, without a clear national narrative on the role of the grid, it is often deprioritised.

3.3.7. Connection bottlenecks and misaligned incentives

Renewable developers increasingly face years-long waits for grid connection, especially in countries like the UK, Ireland, and Australia.

In some cases, developers are incentivized to apply for connections early, “locking up” capacity they may not need. This clogs up the connection queue and delays shovel-ready projects.

Transmission planners often lack visibility of the true project pipeline, limiting their ability to anticipate needs and make proactive investments.

3.4 Most urgent types of grid investment

To support the global energy transition, investment in grid infrastructure must be dramatically scaled and targeted. Urgency varies by region and context — but broadly, investment needs fall into five key categories: new grid rollout, upgrades to existing grids, cross-border interconnectors, and system stability solutions like synchronous condensers. Each plays a distinct role in enabling clean, reliable electricity systems.

Investment Type	Primary Role	Example Region / Country
New Grid Rollout	Basic electrification and access	Nigeria, Ethiopia
Transmission Expansion	Connecting renewables to demand	United States
Distribution System Upgrades	Managing EVs, rooftop solar, and bidirectional flow	Australia
Grid Digitization	Real-time operation and efficiency	India
Cybersecurity / Climate Resilience	Protecting grid against attacks and extreme weather	California
Cross-Border Interconnectors	Regional balancing and trade	Ireland, Spain
Synchronous Condensers / Stability Tech	Grid stability in high-renewables systems	Ireland
Battery Storage and Flexibility Assets	Balancing supply-demand and relieving constraints	United Kingdom

3.4.1. New grid rollout: expanding access and enabling development

Basic electrification requires the buildout of transmission and distribution lines, transformers, and substations in areas with limited or no grid access. Over 700m people globally lack access to electricity. Connecting them to reliable power is both a development priority and a climate opportunity (by leapfrogging fossil fuels).

E.g. in **Sub-Saharan Africa countries like Nigeria, DR Congo, and Ethiopia** need large-scale investment in grid access and mini-grid systems, supported by concessional capital and development finance.

3.4.2. Grid reinforcement and modernization: upgrading existing infrastructure

Investment in existing grids is needed not just to keep pace with demand, but to enable the integration of renewables, electrification of new sectors, and digital operation.

Four priority upgrade types stand out, as listed below.

3.4.2.1 Transmission expansion

New high-voltage transmission lines are needed to connect renewable-rich regions with urban demand centres. Wind and solar resources are often located far from population hubs, requiring long-distance bulk power transport.

E.g. the lack of long-haul transmission in the **US** between the Midwest (rich in wind) and the East Coast (high demand) is a major bottleneck for renewables buildout.

3.4.2.2 Distribution system upgrades

The reinforcement of low-voltage networks is needed to manage bidirectional flows, distributed energy resources (**DER**s), and electric vehicles (**EV**s). Rooftop solar, batteries, and EVs introduce volatility and congestion risks at the local level.

E.g. In **Australia**, the rapid growth in rooftop solar has strained distribution networks, especially in suburban areas.

3.4.2.3 Grid digitization

Deployment of smart meters, sensors, data platforms, and automated control systems is needed to enable a responsive, resilient grid. A digital grid allows for real-time monitoring, remote fault detection, and demand-side flexibility, which is essential for balancing variable renewables.

E.g. In **India**, digital upgrades are needed to reduce losses, improve efficiency, and support integration of solar at scale.

3.4.2.4 Cybersecurity and resilience
Investment is needed in cyber protection, backup systems, and grid-hardening against climate risks (e.g. storms, wildfires). This is required because as grids become more digital and distributed, they also become more vulnerable to attack and weather events.

E.g. In **California**, grid shutdowns during wildfires and rising cyber threats make resilience a critical investment area.

3.4.3. Cross-border interconnectors: sharing power across regions
High-voltage direct current (**HVDC**) or alternating current (**HVAC**) links between countries or markets are needed to enable electricity trade and flexibility. Interconnectors reduce the need for individual system balancing, lower overall costs, and enable surplus renewable energy to flow where it is needed.

E.g. European countries like **Ireland and Spain** urgently need new interconnectors to absorb excess renewables and improve system reliability. The UK-France and Ireland-France Celtic Interconnector projects are key steps.

3.4.4. Synchronous condensers and grid stabilisation technologies
Installation of synchronous condensers (also known as rotating stabilizers) and other grid-forming technologies is needed to maintain voltage and frequency stability in systems with high shares of inverter-based generation. Renewables like wind and solar do not provide inertia or short-circuit strength like traditional generators do. This is leading to increased instability as traditional power plants are retired.

E.g. **Ireland** is a global pioneer in operating with high non-synchronous generation shares and has installed synchronous condensers to enable safe integration of wind without triggering blackouts.

3.4.5. Storage and flexibility assets integrated into the grid
Grid-scale battery storage, flexible demand programs, and other fast-responding assets co-located with transmission and distribution infrastructure are essential assets to reduce peak load pressure, smooth variability, and defer costly grid upgrades.

E.g. In the UK, significant investment in battery storage is underway, particularly near grid constraint zones to reduce renewable curtailment.

3.5 Case study: the April 2025 Iberian blackout

3.5.1. Background
Shortly after midday on 28 April 2025, Spain and Portugal experienced a system-wide blackout. A small part of southern France was briefly affected, but the rest of Europe remained stable. At the time, Iberia had more than enough supply: solar generation was high, demand was moderate, and Spain was exporting power to neighbouring countries.

Despite this comfortable position, the system collapsed within seconds. Power was restored gradually, with Portugal back online by midnight and Spain fully restored by the early morning.

3.5.2. Cause
The blackout was caused by a chain of events rather than one fault. In the half hour before the collapse, the grid showed signs of instability, with unusual swings in power flows between Iberia and France.

At 12:33, several generators in southern Spain tripped almost simultaneously, removing about 2.2 GW of supply (around 10% of demand at that time). This sudden loss caused the system frequency to plunge rapidly.

The system frequency can be thought of as the "heartbeat" of the grid and is normally kept very close to 50 Hz (usually within 49.95–50.05 Hz). Measurements show it fell to around 49 Hz within two seconds, and some reports suggest it dipped below 48 Hz before the system collapsed. Such a sharp deviation is far outside the safe band and triggered widespread automatic shutdowns.

Unlike routine disturbances, which are absorbed by reserves or support from neighbouring systems, this one spread uncontrollably. Three key factors for this spread were as mentioned below:

1. *Weak interconnection*: Iberia's links to France cover only about 3% of demand, far below the EU's 15% target. This meant little outside support could flow in.

2. *Inverter-based generation*: At that moment, solar power dominated. Solar and wind plants connect via electronic inverters rather than heavy spinning machines. Inverters provide very little natural "inertia," so frequency can change dangerously fast.

3. *Protection responses*: Grid equipment is fitted with automatic protections to prevent damage. Many units tripped together in response to the rapid voltage and frequency swings, worsening the cascade.

This chain of events resulted in a system separation and total collapse across Iberia, a much rarer outcome than the contained incidents operators manage every week.

3.5.3. Outcome

The blackout caused major disruption. Rail services were suspended across Spain, airports and telecoms were interrupted, and internet traffic dropped sharply. Hospitals managed using backup diesel generators. Spain's nuclear plants disconnected safely but could not assist in the immediate recovery. Restoration was staged: interconnectors with France and Morocco were energised first, followed by gradual restart of transmission corridors and domestic generation.

For investors, the incident showed the importance of technologies that can stabilise frequency instantly and restart the grid. **Black-start** refers to the ability of certain power plants to start up without any external supply and re-energise the grid after a collapse. In this case, hydropower plants such as Castelo do Bode in Portugal and flexible gas turbines such as Tapada do Outeiro were central to the recovery.

Increasingly, large batteries designed with "grid-forming" capability can play the same role, helping stabilise networks when traditional plants are offline.

3.5.4. Response

Europe's association of electricity transmission system operators (**ENTSO-E**) and national regulators launched investigations, ruling out cyberattack and focusing on protection settings and compliance at certain plants.

- Spain announced measures to expand storage, improve grid operation, and strengthen demand participation, though legislation is still being finalised.
- Portugal committed around €400m to resilience upgrades, including more black-start capacity, new batteries, and grid-forming technologies.
- At the pan-European level, the blackout renewed pressure to speed up construction of interconnectors between Spain and France.

3.5.5. Key lessons

This was not a routine fault: an unusual voltage-driven cascade, combined with weak interconnection and a high share of inverter-based generation forced Iberia into a full black-start scenario. The main lessons align with themes in Section 3.4: build stronger interconnectors, invest in technologies that provide stability (synchronous condensers, advanced batteries), and secure geographically diverse black-start capacity. These are central to regulated investment plans and point directly to investable opportunities.

4. Investment models

Governments, in seeking to incentivise investment by the private sector into critical infrastructure such as electricity systems, have developed different investment models. This section aims to provide a broad overview of these models. Considering the role of government support of these models, institutional investors will need to fully understand the business model, and to establish whether there is primary legislation that protects the investment model, and how exposed the forecasts are to changes in policy.

Investors in electricity infrastructure are exposed to regulatory, policy, market, technological, and climate risk, and as such these risks require vigorous due diligence pre-investment, and monitoring post investment. These risks vary across different investment models, ranging from areas like market design, to subsidy mechanisms (that support either price/revenue or investment costs), to legislation around decarbonisation targets.

For example, the sweeping overhaul of British energy systems was launched with the 1989 Electricity Act, which was three-pronged. This Act privatised ownership, liberalised markets, and unbundled the vertical integration.

This section will discuss the following concepts:

- **Regulated Asset Base (RAB)**
- **Contracts for Difference (CfD):** operational revenue and price support. The revenue support is determined by competitive bidding during the auction, at a single point in time.
- **Capacity Markets (CM)**
- **Power Purchase Agreements (PPAs):** are not government policy support, but a private contract between producer and buyer of electricity – often a corporate. PPAs were originally used by utilities to purchase power from independent producers.
- **Business models for transmission grids**

4.1 Regulated Asset Base (RAB)

The RAB model assesses the value of assets that provide a regulated infrastructure service, often with market-dominant (monopolistic) pricing powers, setting out principles for the calculation of price caps (revenues), and for accounting values of the assets, thereby forming the basis on which the investor or asset owner can generate profits.

The model serves as regulatory commitment by government to the private sector (via regulators, such as OFWAT or OFGEM), where the utility is owned and managed either by a private or by a corporatised state-owned company.

The RAB model was initially used to value existing assets during the privatisation phase in the UK in early 1990s and is still used for critical infrastructure such as water or electricity generation. Today in 2026 it is being developed for nuclear power generation.

Government, through the regulators of critical infrastructure (such as water or electricity) sets guidelines for how these assets are to be valued, how to support construction costs, and how to allow cost-recovery during the construction phase, allowing the utility to charge via consumer bills before the project is operational and revenue generating.

The model is the foundation for calculating the recovery of expenses, including:

- depreciation expenses
- operating and maintenance costs
- investments into new assets that increase the regulated asset base
- financing costs: return on capital, where the permitted return = RAB x WACC
- revenue requirements for regulated utilities (what is the appropriate level of reward or return?)

The model impacts tariff profiles, which can either delay cost recovery, or bring forward cashflows. Two main approaches for modelling inflation:

- Nominal RAB x Nominal WACC: assets are valued today, without inflation adjustment, but multiplied by a WACC that includes inflation.
- Real RAB x Real WACC: assets are implicitly adjusted by inflation and holds their value over time and multiplied by a real WACC since inflation is compensated through tariff indexation.

One key concern is that these models might encourage excessive capital expenditures, in order to strategically inflate the base on which the permitted return is calculated.

4.2 Contracts for Difference (CfDs)

Originally, CfDs were derivatives used in the financial markets, but which were later adopted for use as government support mechanisms (a subsidy) for renewable energy generation.

4.2.1 Origins of CfDs

The UK was the first to develop and implement what is often referred to as the conventional CfD. Other types of CfD have since been developed in different jurisdictions. In 2013, the UK passed The Energy Market Act, which introduced the policy of Electricity Market Reform (**EMR**) to incentivise investment in secure, low-carbon electricity. The EMR introduced two mechanisms:

- a capacity market (**CM**) designed to help ensure security of electricity supply at the lowest cost to the consumer.
- CfDs, designed to provide long-term revenue stabilisation for new low-carbon initiatives.

4.2.2 Risk sharing for institutional investors

CfDs are a risk-sharing subsidy which hedges the systemic market risk of wholesale spot prices, and which cannot be diversified away.

At the project development stage, asset owners (project sponsors) and institutional investors need to establish whether upfront capital cost will be covered with revenue from electricity production once the project is operational.

CfDs mitigate this market risk by reducing the wholesale market price volatility. Reducing price risk lowers the volatility of revenue, which enables a lower cost of capital and, by extension, reduced levelized energy costs. A 15-20 year revenue subsidy creates a stable revenue profile, enabling the use of non-recourse project finance, i.e.

a leveraged debt structure created specifically for the project, in which lenders rely solely on the cash-flows from the project for repayment of debt. This in turn enables a reduced cost of capital, with longer debt-tenures and lower interest rate premiums. This long-term profile is useful for institutional investors. Factors influencing the market price are energy market dynamics and the overall economic outlook.

Developers of renewable energy assets also face legislative, policy and market design risks, which are also not possible to hedge.

Project specific risks, such as reliance on specific suppliers for critical components fall under the responsibility of the project developer and are not mitigated by a CfD.

4.2.3. Allocation through a competitive bidding process

CfDs are applied for via a competitive bidding process. If successful, generators are awarded a 15-to-20-year CfD and a set of obligations to deliver the contracted capacity within a specified time.

4.2.4. Mechanics of conventional CfDs

The defining feature of a CfD is the difference between the wholesale market price and the strike price, agreed in accordance with the CfD counterparty, in a private law contract, where government supports revenue risk, meaning developer/investor bears all construction risk until project is operational.

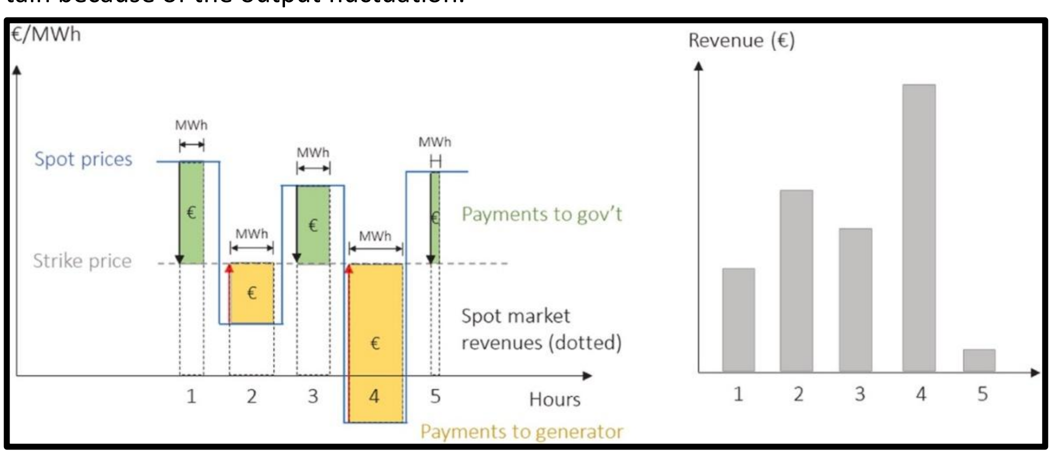
The CfD is linked to the hourly generation of a specific asset. Payments are coupled to the asset's production. Main characteristics include:

- a fixed strike price.
- underlying variable is the hourly day-ahead spot price.
- the contract is linked to a specific physical asset.
- volumes are "as produced" in every hour.

The hourly payment obligation is calculated as: ***Payment*** $_{t}$ ***= (strike price – spot price*** $_{t}$***) x produced volume***

If the strike price exceeds the spot price, governments make a payment to generators, and vice versa. The fact that it is physical production (metered output) that determines the payments is why these CfDs are sometimes called "injection based."

The figure below illustrates payments over 5 hours. Each hour's payment is calculated as the price difference (height of the boxes) multiplied by the production (width). While this results in stable per-MWh prices, revenues remain uncertain because of the output fluctuation.



While the conventional CfD is in some ways like a financial derivative such as a future or a forward contract, the fact that it is linked to a specific asset makes it different. Not only does this make it impossible to trade CfDs on secondary markets (without selling the asset as well), but more importantly, it entails that CfDs provide incentives to adjust the dispatch of the asset to manipulate payments.

4.2.5 Problems with and alternatives to conventional CfDs

The conventional CfD structure has raised some problems:

1. The "produce and forget" incentives and muted electricity price signals: There is no benefit to the generating company to produce electricity when it is most needed, i.e. when prices are high.
2. The distortion of the intraday and balancing markets.
3. Unhedged volume risk: CfDs hedge price but not volume (kWh) risk. Therefore, cashflow remains uncertain owing to the variability of weather inputs and generating assets remaining exposed to volume fluctuations such as variability in wind speeds. For example, a period with low wind (low kWh generated) is compensated by higher prices; whereas under the CfD, low wind means reduced revenues as the price is "muted".

4.3 Capacity Markets (CM)

Capacity Mechanisms or Markets (**CM**) are support measures to provide investment support for reliable sources of capacity. Generators are paid to ensure they are available when needed. This payment is separate to the revenue from electricity generation. Power plants are remunerated for the medium and long-term security of electricity supply. In the Nordic area, it is called the automatic Frequency Restoration Reserves (**aFRR**) balancing capacity. In the UK, the Electricity Market Reform (EMR 2014) package introduced regulation for CMs, alongside the CfDs.

In the UK generators with low-carbon support (such as CfDs, FiT, RO[1]) are not eligible to take part in the CM payments. When the UK electricity market was first privatised, capacity payments were built in. Generating power plants that were dispatched under the CM were paid the Pool Purchase Price (**PPP**).

Pool Purchase Price per MWh = SMP + LOLP x VOLL

- SMP (System Marginal Price): Price of the most expensive unit dispatched
- LOLP (Loss of Load Probability): Risk of a capacity shortfall
- VOLL (Value of Lost Load): £2,000/MWh in 1990/91, inflation-linked

A key issue is finding the flexibility of how to integrate variable/intermittent renewable energy supply with the inflexible supply from "baseload" sources like nuclear power plants (they are either on, or off).

4.4 Power Purchase Agreements (PPAs)

PPAs are <u>not</u> government policy support, but a private contract between producer and buyer of electricity (often a corporate). PPAs were originally used by utilities to purchase power from independent producers.

PPAs have since become a tool for corporations to procure green energy for corporate sustainability goals, and to hedge electricity price volatility, predominantly in solar and wind generation.

[1] Feed-in-Tariffs (a fixed tariff; discontinued to new projects), and Renewable Obligations (RO's) are not discussed in this paper.

PPAs provide long-term revenue certainty for the producer – dominated by large corporate sellers and energy companies, such as RWE and Iberdrola.

4.4.1 Physical and virtual PPAs

Physical involves the physical delivery of electricity from producer to buyer.

Virtual PPAs decouple physical delivery from price risk, contracting only the attributes of the electricity produced, such as a renewable energy certificate. The buyer pays a fixed price to e.g. a renewable energy producer, but the actual electricity is sold on the wholesale market. The buyer receives the environmental credit, such as a ROC, and the revenues for the sale onto the wholesale market.

4.5 Business models for transmission grids

Business models which can be used to facilitate private investment in transmission grids include:

- whole network concessions
- independent transmission projects (**ITP**s), aka independent power transmission projects
- privatisation (the governments sell shares in a state-owned utility or transmission company)
- merchant lines

The below table breaks down key characteristics of the business models used to privately finance transmission grids. The table is based on publications from the IEA (Attracting private investment to the electricity transmission sector in Southeast Asia, 2020) and the World Bank (Linking Up: Public-Private Partnerships in Power Transmission in Africa, 2017).

	Long-term concession	**Build-own-operate-transfer (BOOT)**	**Financial ownership**	**Merchant line**	**Dedicated line**
Description	Private company obtains the long-term concession to manage and operate existing transmission assets and oversees expanding the transmission grid in its area of operation.	Private company finances, builds, and operates a new transmission line under a long-term contract. After that, it transfers it back to the government.	Private company provides part of the financing for a new transmission line, but it is built and operated by the system operator.	Private company finances, builds, and operates transmission line, with revenues coming entirely from short-term wholesale transmission market prices.	New line evacuating power from Independent Power Producer (IPP), connecting to existing grid.
Contract duration	Long term (30-50 years) or indefinite.	Long term (often 25 years or more).	Indefinite, but possibly with buy back option for the system operator.	Indefinite	Same as IPP unless line is transferred at commissioning.
Contract coverage	All existing and new lines in a limited transmission zone (country, region).	New line (or sometimes a package of lines).	New line.	New line, often HVDC.	New line.
Revenue / tariff setting	Regulated revenues, generally defined annually and subject to periodic regulatory review.	Majority of revenues defined by winning bid, for the entire contract term.	The scheme normally applicable to system operator, e.g. congestion rents or regulated revenue.	Revenues from wholesale market prices. Sometimes supported by price mechanisms (e.g. cap-and floor scheme).	If line not transferred, revenues defined as part of IPP contract payment.
Who funds capital expenditure?	Private sector.	Private sector.	Private sector and system operator.	Private sector.	Private sector.
Applicable to interconnectors?	Limited.	Yes, if the line in each side of the border is built on a BOOT scheme.	Yes.	Yes, but requires restructured markets and a primary model for multilateral power trading.	Not recommended since this implies cross-border integration of specific assets instead of grid integration.
International examples	Philippines, Scotland, and other parts of Europe.	Brazil, Chile, India, UK, Australia, USA, among others	Denmark and Germany.	USA and Australia.	Globally applied.

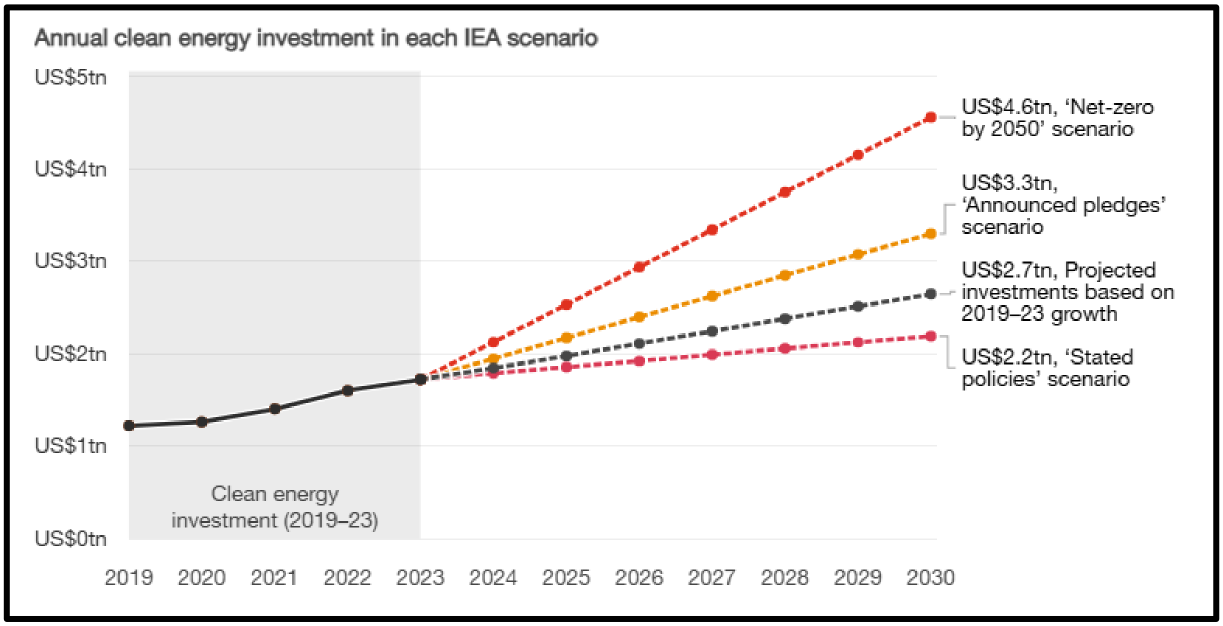
5. Role of LTIIs

5.1 Background

According to a World Annual Energy Investment report, the global energy investment was set to exceed $3 trillion for the first time in 2024, including $2 trillion invested towards clean energy technologies and infrastructure. Clean energy investments have increased since 2020 in the areas of renewable power, grids, and storage, with total investment in these areas now higher than total investments in oil, gas, and coal. Increased spending in clean energy is promoted by a reduction in the carbon emissions, technological gains, and energy security imperatives (mostly in the EU). These factors are driving clean energy manufacturing.

Clean energy investments have seen a major increase, to record levels, but there remains a deficit in funding the energy transition. As per the estimates of International Energy Agency (**IEA**), $4.6 trillion of investment will be required to achieve net zero emissions by 2050. Financing the energy transition is both a challenge and opportunity for LTIIs. Long-term investors may be able to take short-term risks like early-stage technological risk and project risk from emerging economies, which other investors will be reluctant to take.

The following graph captures potential investment paths to 2030:



Note: *'Clean energy investment' includes renewable power, nuclear energy, electricity grids, storage, low-emissions fuels, efficiency improvements, end-use renewables, and electrification.*

Source: PwC's Global AWM & ESG Research Centre, IEA

Net zero can be achieved only if the gaps between the current energy system and a clean energy system are addressed. These gaps are mostly related to the development of renewable energy capacity. Namely the solar and wind farms, chemical battery storage systems, and hydroelectric dams needed to supply clean electricity in the world. The next section highlights some of the energy gaps which might offer significant potential to LTIIs.

5.2 Potential areas for LTIIs to invest in

- **Widespread electrification:** Mass electrification is one of the most effective measures to achieve decarbonisation, but there is a long way to reach towards net zero. There is a growing trend towards electrification in residential buildings, demand for electric cars, and electric-powered industrial production.
- **Gap in storage systems:** Fluctuation in weather patterns means that renewable energy does not produce a constant stream of energy. Therefore, batteries are the primary potential source of storage.
- **Digital infrastructure power requirement:** Usage of AI and cloud computing have caused an increase in global electricity demand. This highlights that the energy transition will need not only to replace the existing supply but also to produce even more than the current global output.
- **Demand for critical minerals:** Demand for the battery metals e.g. lithium, cobalt, and nickel is rising sharply due to increased competition among automakers and the volatility in the cost of these raw materials. Further, the growing electrification of energy systems has amplified the demand for copper metal.

5.3 List of notable LTII investments in the energy transition

Investor Name	Type	Country	Grid Investment Focus	Notable Investments
Allianz Capital Partners	Life Insurer (Investment Arm)	Germany	Transmission grids, offshore wind connections	Stake in TenneT (Germany/Netherlands transmission operator)
CPPIB (Canada Pension Plan Investment Board)	Pension Fund	Canada	Transmission, distribution, renewables	Investment in Avangrid (US grid, renewable assets), European transmission networks
OTPP (Ontario Teachers' Pension Plan)	Pension Fund	Canada	Electricity grids, global energy infrastructure	Stakes in TransGrid (Australia), European transmission assets
Macquarie Infrastructure and Real Assets (MIRA)	Asset Manager (Institutional Clients)	Australia	Global T&D infrastructure	Ownership in Cadent (UK gas network), National Grid gas transmission
Brookfield Asset Management	Asset Manager (Institutional Clients)	Canada	Transmission networks, energy transition infrastructure	Investment in North American and South American transmission grids
GIC (Singapore Sovereign Wealth Fund)	Sovereign Wealth Fund	Singapore	Regulated grid assets globally	Co-investor in National Grid Gas (UK), other regulated utilities
ADIA (Abu Dhabi Investment Authority)	Sovereign Wealth Fund	UAE	Transmission/distribution infrastructure	Stakes in UK and European energy infrastructure via funds
IFM Investors	Pension Fund-owned Manager	Australia	Transmission & distribution, energy transition	Owner of major stakes in Ausgrid (Australia), global energy infrastructure
CDPQ (Caisse de dépôt et placement du Québec)	Pension Fund	Canada	Transmission, distribution networks	Ownership in Invenergy Transmission (USA), energy transition platforms
APG (Dutch Pension Fund Manager)	Pension Fund	Netherlands	Electricity grids, smart grid development	Partner in European T&D upgrades; stakes in Dutch transmission grids
AustralianSuper	Pension Fund	Australia	Electricity grid infrastructure	Stakeholder in TransGrid (Australia), energy transition projects
PGGM	Pension Fund	Netherlands	Electricity T&D, energy networks	Co-investor in European grid modernization projects
QIC (Queensland Investment Corporation)	Sovereign Wealth Manager	Australia	Regulated energy infrastructure	Major stake in Powering Queensland Plan, grid infrastructure
National Grid Pension Fund	Pension Fund	UK	UK electricity grid & T&D infrastructure	Direct exposure via National Grid Plc