Navigating risks to unlock 500 GW of renewables by 2030

Assessing investment risks is key to designing effective risk mitigation mechanisms. This becomes critical to ensure the necessary flow of capital to drive growth in the renewable energy sector.

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Neshwin Rodrigues
Duttatreya Das

About

India requires unprecedented investment in renewables, storage and grids to achieve its target of 500 GW of clean power by the end of the decade. Facilitating this large-scale infrastructure build-out demands low-cost capital, which hinges on effectively managing risks. This report examines investment risks in India's renewable energy sector and outlines strategies to address them.

Highlights

$300B

Total investment required by 2032 to meet India's National Electricity Plan-14 targets.

+4%

Maximum increase in cost of capital to factor in risks associated with new-age dispatchable renewable projects and commissioning delays

100 GW

less renewables by 2030 if cost of capital remains elevated by +4%

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Executive summary

Understanding and mitigating financing risks is key to enabling low-cost capital flows for India's renewable sector

India stands at a pivotal moment in its renewable energy journey, with an ambitious target of 500 GW by 2030 requiring significant investment. Achieving this scale hinges not only on the availability of capital but also on ensuring it is available at a low cost. Attracting low-cost capital is critical on two fronts: enabling the development of renewable energy infrastructure at the required scale and ensuring that the promise of affordable renewable electricity is realised.

This report highlights key challenges in India's renewable energy (RE) sector that could increase the cost of capital, potentially hindering the sector's growth. Addressing these risks through targeted policy measures, innovative contracting mechanisms and proactive expectation management is crucial for maintaining a steady flow of investments. Collaborative efforts from project developers, financiers and policymakers will be indispensable in mitigating these risks and ensuring the successful realisation of India's ambitious RE targets.

Key takeaways

01 Total renewable power investments must reach USD 300 billion by 2032 to meet NEP-14 targets

Investments in renewable power generation and transmission for FY 2024 are estimated at USD 13.3 billion, marking a 40% increase from the previous year. Achieving the National Electricity Plan (NEP)-14 targets will require annual financing to grow by 20% annually, reaching USD 68 billion by 2032. Over this period, a total capital flow of USD 300 billion will be needed to keep India on track to meet its renewable energy commitments.

02 Commissioning delays and risks from new-age FDRE projects can drive up the cost of capital by 4%

Project commissioning delays, driven by land acquisition challenges, grid connectivity issues and regulatory hurdles, remain a significant concern for India's renewable energy sector. Furthermore, Firm and Dispatchable RE (FDRE) projects, designed to enhance renewable energy dispatchability through oversizing solar and wind projects and integrating storage, can introduce additional risks. These include penalties for failing to meet demand targets, exposure to market price fluctuations, and uncertainties surrounding future battery costs. Combined, risks from project delays and FDRE projects have the potential to raise the cost of capital by up to 4% or 400 basis points (bps ~ equivalent to 1/100th of 1%, or 0.01%).

03 A 400 bps increase in the cost of capital could cause India to fall short of its 2030 RE target by 100 GW

A 400 bps rise in the cost of capital—from 10%, i.e., an average estimate of cost of capital for Indian renewable projects, to 14%—could restrict India's 2030 renewable energy capacity to approximately 400 GW, falling short of the 500 GW target. In contrast, a 200 bps reduction—from 10% to 8%—could allow India to exceed its target, reaching 540 GW. Effectively managing risks and lowering the cost of capital will be critical to sustaining renewable energy growth.

"Understanding project-specific financing risks for RE projects is key to designing targeted mitigation measures that keep the cost of capital low. Staying attuned to evolving risk profiles in renewables is essential for sustaining their growth and ensuring India meets its RE targets."

Neshwin Rodrigues
Senior Energy Analyst for India, Ember

"Besides offering a detailed assessment of key risks in India's renewable markets, this report presents a transparent risk premium assessment methodology for renewables. By demystifying the quantification of risks and their magnitude, it ensures that all RE stakeholders—developers, financiers, and policymakers—have access to a structured framework for evaluating risks. This, in turn, can lead to more targeted policy interventions and contracting mechanisms that effectively mitigate risks."

Duttatreya Das
Energy Analyst for India, Ember

"There has been a surge in Letters of Award (LoAs) for renewable energy projects, but many of these have not yet materialised into Power Purchase Agreements so far. The Ministry of Power must address this issue, as the delay imposes financial strain on developers due to bank guarantee costs and creates uncertainty for equity investors in forecasting cash flows based on LoAs."

Satyadeep Jain
Director - Equity Research,
Ambit Private Limited

"Risks in RE projects are constantly evolving, making a contemporary understanding crucial for developers and investors. Research like this must be regularly updated to quantitatively reflect the evolving risk profile."

Abhishek Jain
VP, Investment Cell,
O2 Power

Critical role of risk assessment in driving India's energy ambitions

Higher risks in renewable energy projects can drive up the cost of capital and limit access to finance, hindering the achievement of renewable energy targets.

Meeting India's renewable energy targets requires annual finance flows to grow to around USD 68 billion by 2032, requiring a 20% annual increase. Effectively addressing sectoral risks is crucial to unlocking this investment potential.

India's energy transition requires significant increase in financing

India has reaffirmed its commitment to the global energy transition with an ambitious target to decarbonise its power sector. At COP26, Prime Minister Modi announced a goal of achieving 500 GW of non-fossil fuel capacity by 2030. While this target was not officially included in India's updated Nationally Determined Contributions (NDCs), it remains a key guiding reference in national energy planning documents, including the 14th National Electricity Plan (NEP-14).

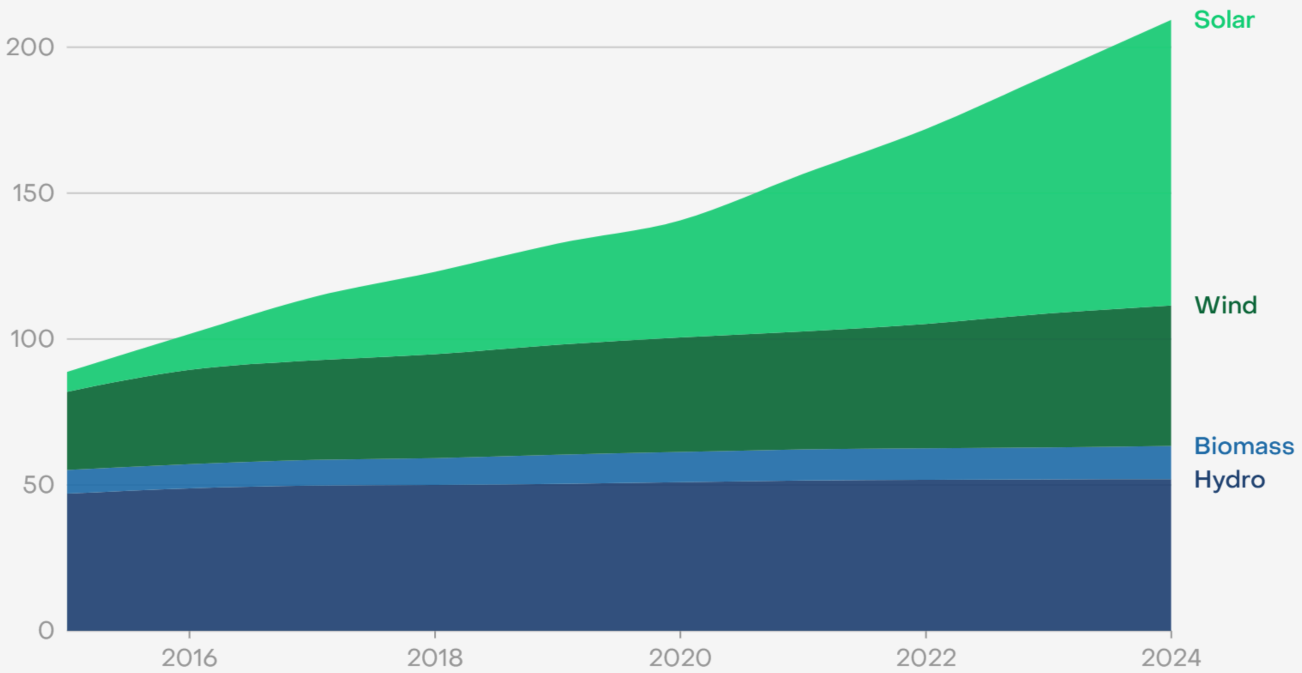
NEP-14 incorporates this goal, targeting 596 GW of RE capacity by 2032. This would account for 68.4% of the country's total installed capacity and meet 44% of its electricity demand. NEP-14 sets specific targets of 365 GW of solar, 122 GW of wind, 47 GW/236 GWh of battery energy storage system (BESS) and 26.7GW of pumped storage plants (PSP), providing a clear roadmap for India's RE expansion.

India's RE growth is already progressing in alignment with these goals. By October 2024, the country had achieved 200 GW of RE capacity, with an additional 151 GW under various stages of development and construction. Beyond large utility-scale projects, renewables have also witnessed widespread adoption by commercial and industrial (C&I) consumers, as well as rooftop installations for retail consumers, driven by various regulatory incentives.

This progress is evident from the significant annual addition of 30 GW of renewables in the calendar year (CY) 2024, which represents a 113% increase compared to 2023. In terms of tendered capacity, 79.3 GW were auctioned in CY 2024, a significant increase from 57 GW in CY 2023. The auction prices were also extremely competitive, as low as 2.48 Rs/kWh (~29 USD/MWh).

India crosses 200 GW renewable milestone in 2024

Renewable energy capacity in GW, by source



Source: Ember's India Electricity Data Explorer

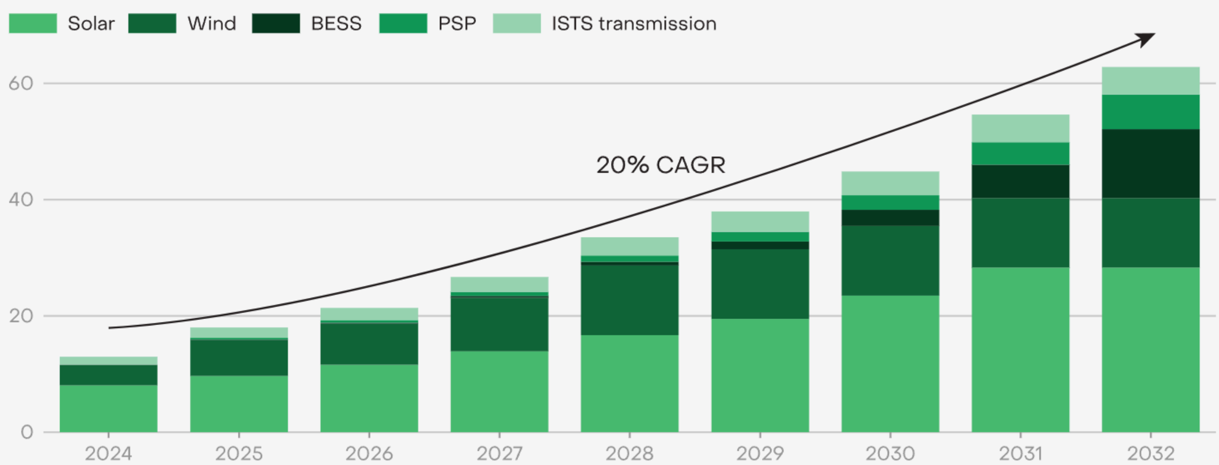
India has emerged as a leading destination for RE investments, driven by its favourable geography, stable regulatory framework and competitive electricity market structures. Through 2023 and 2024, India topped BloombergNEF's Climatescope index, which ranks countries based on their attractiveness for clean power investments. Notably, India has consistently remained among the top five emerging countries over the past five years leading up to 2024.

India's RE sector has matured over the last decade, supported by policy frameworks such as renewable purchase obligations (RPOs), waivers on Inter-State Transmission System (ISTS) charges, solar park initiatives and favourable open access policies for C&I off-takers. These measures have created enabling conditions for competition, successfully attracting capital and encouraging independent power producers (IPP) to participate in the development of India's RE ecosystem.

India's RE financing landscape has evolved significantly over time, leveraging a diverse range of sources. Equity investments in India's renewable sector have been made by global investment and pension funds (such as Brookfield, CDPQ), large Indian corporations (Adani, JSW, NTPC), and international oil companies (Petronas, TotalEnegies). On the debt side, funding has been sourced from banks (SBI, Axis), energy focused non-banking financial companies (IREDA, REC), and development financial institutions (World Bank).

Financing for renewable energy, storage, and transmission has to increase by 20% each year to meet India's 2032 RE target

Projected annual financing need in billion USD



Source: Ember's analysis of the investment required to achieve India's National Electricity Plan (NEP14) target · The values are for respective financial years
BESS, PSP, and ISTS stand for Battery Energy Storage System, Pumped Storage Project, and Inter-State Transmission System, respectively.

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Investments in renewable power generation and transmission for financial year 2024 were estimated at USD 13.3 billion, a 40% increase from the previous year. However, to meet the targets outlined in the NEP-14, annual financing must grow at a consistent rate of 20% each year, reaching USD 68 billion by 2032. The RE financing ecosystem must rapidly evolve to support this scale-up. A cumulative investment of USD 300 billion would be needed to meet India's 2030 RE target of 500 GW, a critical checkpoint for NEP-14.

This would be crucial for scaling RE generation and enhancing grid storage capabilities—particularly with new-age tenders mandating dispatchable renewable generation. Also, rapidly expanding the transmission network to efficiently evacuate power from RE-rich regions to key demand centres would become important.

Managing risks to lower the cost of capital is key to RE growth

RE infrastructure, characterised by high capital intensity and long gestation periods, often relies on financing structures such as project finance. In project finance, debt repayment depends solely on the project's cash flow, with no recourse to external earnings or collateral if the project fails. The absolute reliance on an individual project's revenues introduces significant risk, and the absence of fallback options makes thorough risk assessment essential.

The availability of capital for renewable projects is a crucial factor in determining whether renewable infrastructure can even be envisioned. Political and economic challenges significantly influence capital availability in a region. For instance, regions affected by conflict or countries with underdeveloped financial systems often pose high investment risks. These conditions can elevate risks to unmanageable levels, significantly restricting the flow of capital for infrastructure projects.

In regions where the availability of capital is not a pressing issue, the cost of capital (CoC) becomes a key factor in RE growth. The CoC generally increases with higher risks, as investors demand a premium over prevailing rates to engage in projects despite prevailing uncertainties. This is rooted in the fundamental philosophy of investment, where most investors prioritise minimising losses over seeking super-normal profits.

CoC represents the minimum return required to justify investments in capital-intensive projects, such as constructing a solar photovoltaic plant or wind farm. It serves as a benchmark for assessing whether a project's anticipated returns can sufficiently cover its costs and meet minimum revenue expectations.

RE projects typically secure capital from diverse sources, each with varying risk-return expectations. The overall CoC for a project is therefore calculated as the weighted average of all capital sources, technically referred to as the weighted average cost of capital (WACC). For simplicity, this report refers to WACC as CoC.

Keeping the CoC low for RE projects is essential for the sector's growth for two key reasons. First, a high CoC can discourage renewable project development given the significant upfront capital expenditures required for such projects. Second, a high CoC increases project costs, often resulting in higher electricity prices to meet investor payback requirements. This, in turn, impacts the accessibility and affordability of renewables, a critical theme for modern energy infrastructure. Recognising this challenge, the report examines the primary drivers of CoC—risks.

Understanding different type of risks becomes important

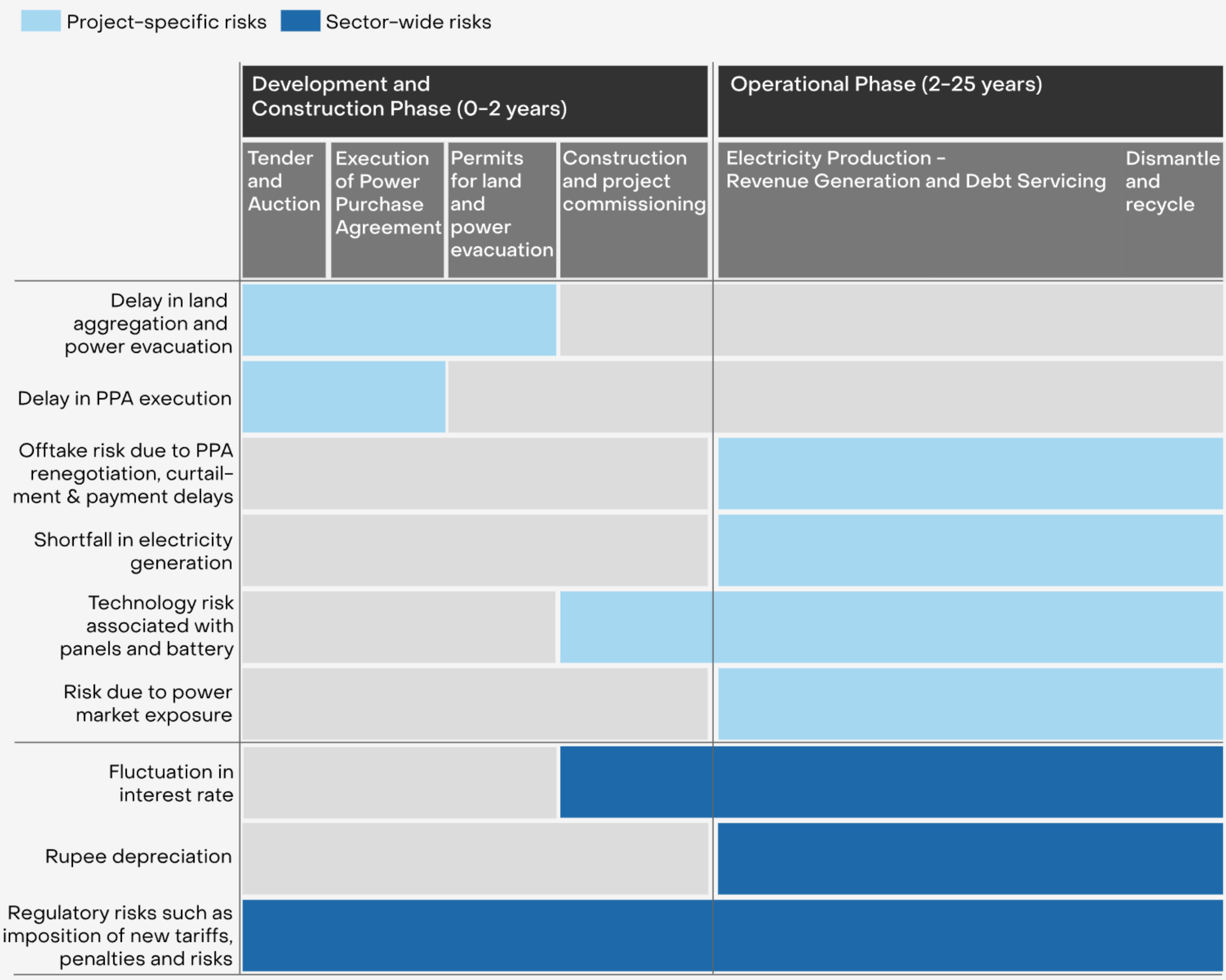
Effectively mitigating risks—whether through regulatory changes or innovative contracting mechanisms among private parties—requires a thorough understanding of historical data and risk forecasts. This understanding serves as the foundation for planning interventions to minimise risks and reduce the CoC.

Despite extensive financial literature on risks around infrastructure projects, this attempt simplifies the categorisation of risks specific to renewable projects. Risks can be broadly divided into two categories:

- **Project-specific risks:** These relate to the development, construction and operation of individual renewable projects, such as a utility-scale solar plant. Examples include challenges in land acquisition, power evacuation, generation shortfalls and other project-specific risks.

- **Sector-wide risks:** These affect all renewable projects within a region and stem from broader macroeconomic factors. Examples include interest rate fluctuations, exchange rate volatility and sector-wide policy changes, such as abrupt tariff adjustments or restrictions on the import of solar panels.

Multiple risks impact a renewable project at various stages of its lifecycle



Source: Ember

This report primarily focuses on project-specific risks and does not explicitly address the macroeconomic factors influencing risks in the broader sector. Understanding project-specific risks within the Indian context and their relative importance is crucial for all stakeholders in a RE project, particularly developers and financiers. Additionally, the report highlights measures to minimise or mitigate these risks through targeted interventions.

Chapter 2: Measuring risks

Cracking the risk premium puzzle

Quantifying risks provides a clear understanding of their relative significance and impact on the cost of capital. It also enables businesses and policymakers to prioritise risk management strategies better.

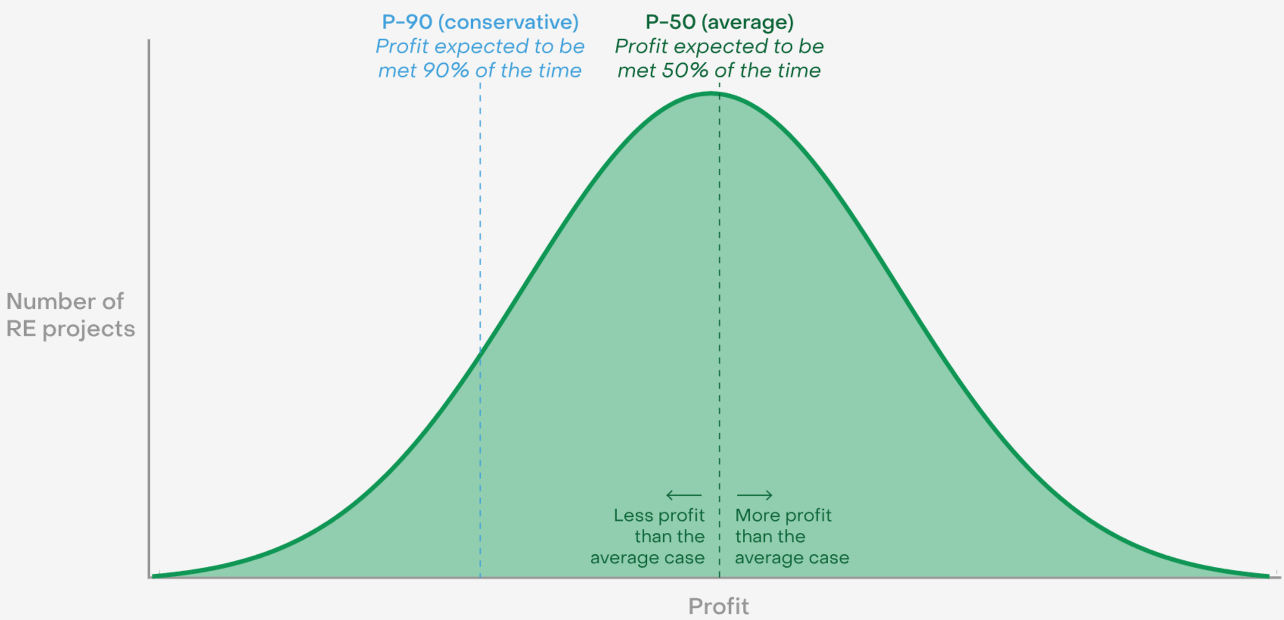
Major contemporary risks such as heightened commissioning delays and risks associated with new-age firm and dispatchable RE projects, can drive up the cost of capital by up to 400 basis points.

A primer on assessment of risk premium

Risk refers to the uncertainty around the achievement of expected outcomes, which can result in actual cash flows deviating from initial estimates. These deviations impact both the quantum of profit generated and the timing of receipts. The returns on investments, logically, should follow a normal distribution, where certain expected outcomes are more probable, while extreme outcomes—either very high or very low—are less likely. This concept applies to RE project investments as it does to any other type of investment.

Uncertainty around expected events can impact returns in RE projects

Probability distribution of profits in an RE project



This figure is for illustrative purposes only.

To evaluate risk premiums, project returns are often assessed using different scenarios that capture a range of possible outcomes. Two commonly used benchmarks for measuring uncertainty in RE projects are the P50 and P90 estimates:

- **P50 (average scenario):** This represents the most likely outcome, with a 50% probability that actual results will meet or exceed this level. It is considered a balanced estimate of expected returns.
- **P90 (conservative scenario):** This represents an outcome with a 90% probability that actual results will meet or exceed this level. P90 is favoured by very risk-averse investors, as it ensures preparedness for unfavourable outcomes.

The choice between using P50 and P90 estimates reflects an investor's risk tolerance. For example, if historical data shows that the capacity utilisation factor (CUF) for a solar project ranges between 18% and 22%, a risk-averse investor might assume a CUF of 18%, while a less risk-averse investor may use a more balanced estimate of 20%. Institutions providing debt, such as banks, tend to be significantly risk-averse and evaluate projects using P90 estimates, whereas equity investors often adopt a slightly less risk-averse approach and use the P75 or P50 estimates. This distinction reflects the different risk appetites of different investor groups in RE projects. For the purpose of this report, P90 estimates are used throughout to maintain uniformity and discuss uncertainties from the point of view of a risk-averse financier.

This report employs the certainty equivalent method to quantify risks associated with uncertainties across a solar project's lifecycle (explained further in the methodology). By applying a "haircut" to projected profits in the average scenario, this method generates conservative profit estimates. The difference in projected profit levels between the average and conservative scenarios serves as the basis for calculating the risk premium. For example, to estimate the risk premium for CUF variability, profits at a CUF of 18% (conservative) would be compared with profits at a CUF of 20% (average).

The following sections discuss major project risks in the Indian RE sector, examine the business and regulatory factors influencing these risks, and offer potential guidance on mitigating specific risks.

Risks associated with project delays

An RE project is said to be 'commissioned' the day it becomes operational and starts generating electricity. Delays in commissioning occur when an RE project fails to meet its planned operational timeline. These delays often arise during the construction phase from issues such as land acquisition, regulatory approvals and grid connectivity challenges, potentially extending timelines by months or even years.

Delays in commissioning directly impact project cash flow, disrupting both costs and revenues. On the cost side, delays lead to additional costs for manpower and inventory. Additionally, loans continue to accrue interest over the period of non-operation, and developers also face opportunity costs from tied-up equity. Industry estimates suggest that investments in land acquisition, site preparation and other permitting charges could account for 10-25% of the total capital costs for RE projects.

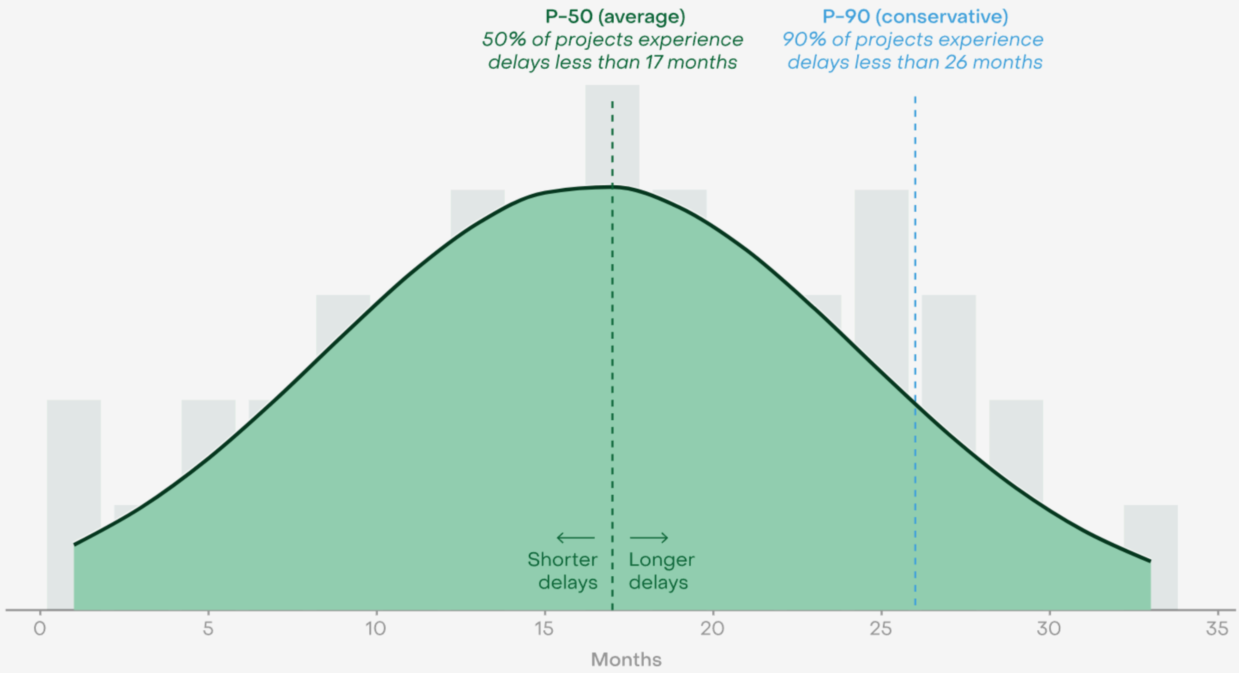
On the revenue side, delays postpone electricity generation, deferring revenue from electricity sales. Penalties under Power Purchase Agreements (PPAs) for missed commissioning deadlines further exacerbate the financial strain.

Disruptions in cash flow during the early phases of a project are particularly detrimental, as they have a greater impact on financial models due to the inherent time value of money. Also, this affects the ability to service debt on time and build cash reserves for initial operational challenges.

Utility-scale RE projects in India have been mired with cases of delays due to various factors. Project-level data from the Central Electricity Authority (CEA) shows an average delay of 17 months (P50), with delays extending to 26 months in extreme cases (P90). In some instances, delays have reached up to 34 months, with some projects eventually being scrapped. These delays are measured from the scheduled commercial operation date (SCOD) as specified within the tender documents—typically 18 to 24 months from the date of execution of the PPA.

Average commissioning delay in solar projects is 17 months, can be significantly higher in extreme cases

Probability distribution of commissioning delay for solar projects, in months



Source: Central Electricity Authority (Data till September, 2024) · The data pertains to solar projects greater than 100 MW, based on information available until September 2024. Projects within solar parks are excluded due to unavailability of relevant data.

The specific reasons for project delays are not always documented for every case. However, delays typically arise from three reasons: challenges such as land acquisition for setting up the plant, connectivity to the grid, and finalising PPAs. These are addressed in detail in the sections below. Additionally, with India's RE tendering agencies awarding a record number of projects in 2024, other associated institutions such as distribution companies (discoms) and regulatory commissions are likely to face coordination challenges, subsequently leading to delays.

Delay in land acquisition

Land is critical for setting up RE projects. Solar projects typically require around 5 acres of land per megawatt of installation, making land acquisition a key determinant of project timelines. However, acquiring land for such projects often faces significant delays due to various regulatory and administrative complexities.

Laws governing land in India, particularly regarding ownership, categorisation, and acquisition, are complex due to the federal structure of governance where legislative powers are distributed between the centre and states. While 'land' falls under the jurisdiction of state governments, matters associated with 'acquisition and requisitioning of property' is a concurrent subject, allowing both the central and state governments to legislate. This dual authority often makes land acquisition a contested issue between the two levels of government. As a result, project developers must navigate varying land acquisition laws across states, with procedures differing based on land ownership—whether government, community, or private.

Acquiring government land tends to be more straightforward compared to private land, which often involves case-by-case dealings and challenges arising from fragmented ownership and unclear land records. Additionally, the acquisition of forest and tribal land is governed by distinct laws at the central government level. The involvement of multiple state departments and varying state-level regulations makes land acquisition a significant bottleneck for RE projects.

The process of land acquisition, typically expected to take 6-9 months, can extend to 18-24 months in certain states, posing significant risks to maintaining SCOD timelines. With project commissioning deadlines usually set at 18-24 months post the execution of the PPA, this process of acquiring land can be a major bottleneck.

Although multiple states have policies addressing land acquisition for RE projects, only a few have actually allocated land specifically for RE. Even in these states, administrative hurdles, non-digitised land records, fragmented local regulations and a lack of centralised land policies complicate project development and delay financial closure.

Delay in obtaining grid connectivity

Utility-scale solar generation capacity is typically established in areas with abundant solar resources, such as Rajasthan and Gujarat, and must be transmitted to other parts of the country through transmission lines. Grid connectivity is a prerequisite for commissioning which is granted only when sufficient substation capacity and upstream transmission infrastructure are available.

The process for obtaining General Network Access (GNA) or connecting to the inter-state transmission system (ISTS), as estimated from typical timelines, requires 4.5 to 13.5 months, depending on whether network expansion or augmentation is required. However, connection timelines remain uncertain due to challenges in expanding transmission and evacuation infrastructure.

Building transmission lines can typically take 24 to 36 months, with delays caused by right-of-way issues, natural barriers like rivers and hills, ecological constraints—most importantly the issue of Great Indian Bustard (GIB)—and complex crossings involving highways and railways. In regions like Rajasthan, where GIB-related permitting bottlenecks are prevalent, construction timelines can extend up to 48 months. A 2021 ruling by India's top court has mandated laying of underground transmission lines in areas critical to the conservation of the GIB. This has placed a significant financial burden on project developers, requiring them to bear the higher costs of underground transmission and leading to construction delays.

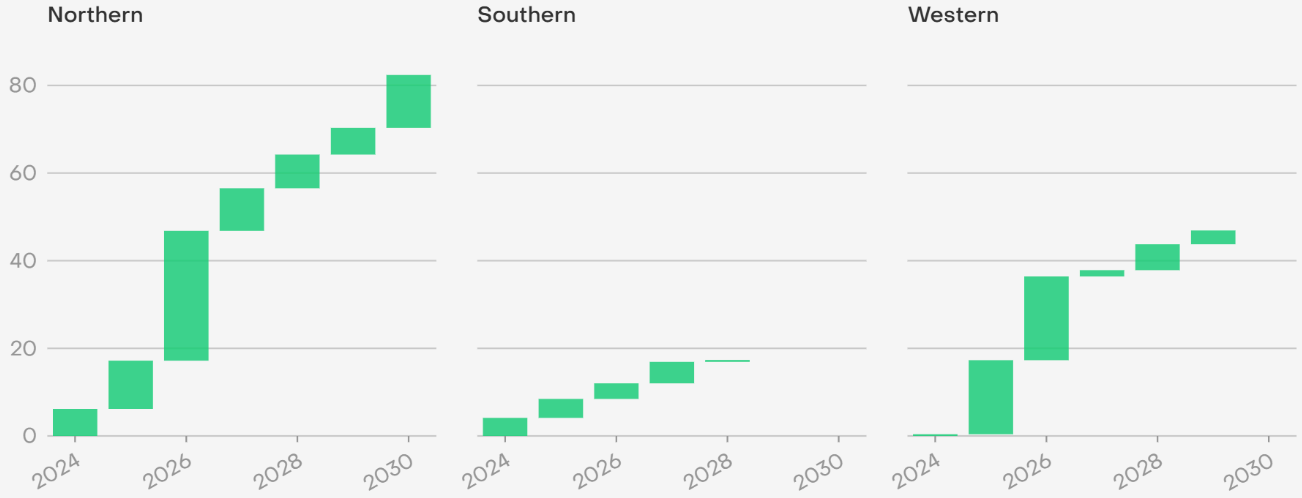
A significant amount of High Voltage Direct Current (HVDC) transmission capacity has been planned and auctioned to facilitate the transfer of RE from these states. But HVDC projects take longer to commission due to its reliance on very specialised equipment, such as converter stations and thyristor valves, unlike HVAC systems that have much simpler equipment requirements.

Higher domestic content requirements in tenders have posed challenges for manufacturers, leading to revisions in tender specifications and subsequent delays. Inadequate local supply chains, transportation challenges for heavy equipment and lengthy permission processes further contribute to extension of project timelines.

The granted grid connectivity for solar, wind, and hybrid projects currently totals approximately 147 GW. However, this capacity is not available immediately and is expected to become operational over the next 3-5 years. The long timelines for transmission infrastructure development introduce uncertainty, posing risks to project commissioning schedules. Delays in planned transmission capacity could hinder the timely evacuation of power, affecting the financial viability of renewable projects.

Project commissioning timelines in India depend on the timely provision of power evacuation capacity

Expected annual availability of new grid connections for upcoming RE capacity (GW), by region



Source: Central Transmission Utility of India Limited · The data shows the expected timeline for RE capacity that will be allowed to connect at pooling stations.
RE pooling stations are designated hubs where power generated from multiple RE projects is aggregated before being fed into the grid.

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Delay in execution of PPAs

The most common route for RE procurement in India is through government-owned tendering agencies such as the Solar Energy Corporation of India (SECI) and the National Thermal Power Corporation (NTPC). These agencies act as intermediaries, aggregating demand from buyers—primarily state distribution companies (Discoms)—and issuing tenders to identify the lowest-cost electricity providers. They then contract power sale agreements (PSAs) with multiple Discoms before finalising power purchase agreements (PPAs) with the project developer. A more detailed explanation of the power contracting process is provided in the methodology section.

However, delays in signing PPAs and PSAs have emerged as significant challenges, affecting project commissioning timelines and developer confidence. As of September 2024, approximately 30 GW of RE projects were yet to find off-takers. For instance, SECI's 2000 MW ISTS Tranche-XI auction held in July 2023 still faces PPA signing delays, highlighting the persistence of this issue.

Some of the main causes of delays in power contracting are outlined below:

- **PSA hold-up:** The power procurement framework varies across states, requiring DISCOMs to secure final approval from their respective regulatory commissions. In some cases, approval is sought before signing the PSA, while in others, it is obtained afterward. This uncertainty can leave developers in limbo until the last moment, unsure if the agreement will pass regulatory scrutiny. For instance, Jharkhand regulators have delayed approvals for over two years, highlighting the challenges posed by state-specific processes.

- **Shifting buyer preferences:** Falling tariffs have fuelled expectations of further bottoming out, leading DISCOMs to delay procurement in hopes of securing lower prices in future tenders. However, with regulations on module localisation and the emergence of dispatchable renewable tenders, prices have not declined as they once did. While SECI has introduced measures like bundling tariffs to bring more uniformity, aligning price expectations remains a challenge—especially as traditional standalone solar and wind tenders fall out of trend.

- **Renewable tendering outpacing procurement:** The record issuance of 69 GW in RE tenders during FY 2024, exceeding the 50 GW target. Traditionally, renewable tendering agencies like SECI would secure off-takers at certain price points before floating tenders. However, this approach has shifted, with SECI aggressively issuing tenders while the off-take arrangement process struggles to keep pace.

These procedural delays in power contracting have created challenges for developers, as they lack clear visibility on deal finalisation. If developers secure equity and invest in land acquisition early, there is a risk that the PPA might not materialise, forcing them to wait for future bids. Conversely, if they delay these processes and wait for PPAs to be signed, they risk missing project timelines and facing penalties. This uncertainty makes it difficult to plan investments and project execution efficiently.

Measures to address project delays

- **Policy for solar parks:** One of the government's notable achievements in nurturing the RE sector has been the development of Solar Parks and Ultra Mega Solar Power Projects, offering plug-and-play facilities for developers. These parks provide large tracts of land equipped with essential infrastructure—transmission, roads, and drainage—along with statutory clearances, significantly reducing costs and delays from scattered land aggregation. The central government's continued support towards the development of 37.5 GW of solar capacity across 50 solar parks highlights the effectiveness of this model.

- **Renewable policy of states:** Many state governments have also eased land availability for RE projects by allotting land parcels in advance under their renewable policies, such as Gujarat's land allotment policy for RE. While states have taken steps to address land acquisition uncertainty, a major overhaul would require harmonising state-level land laws and digitising land records.

- **Transmission infrastructure expansion:** The evacuation and transmission infrastructure has consistently lagged behind the deployment timeline of RE projects and connectivity applications. Issues such as right-of-way challenges and ecological concerns, common worldwide, have slowed RE build-out. The government's Green Energy Corridor project, focused on building transmission lines and electrical substation capacities in RE-rich states, has been a pivotal intervention. However, as RE capacity continues to grow, timely augmentation of major transmission corridors remains critical.

- **Procedural reforms:** A recent regulatory innovation allowing developers to apply for grid connectivity using bank guarantees instead of land acquisition documents, Letter of Award (LoA) or PPA has expedited the application process.

The issue of non-execution of PPA-PSAs has also been addressed by parliamentary committees, which have proposed standardised model formats for PPAs to simplify the negotiation process and expedite PPA-PSA approvals through a time-bound clearance process.

- **Centre-state coordination:** Despite these efforts, the subjects of land and electricity fall under the jurisdiction of state governments, leading to significant coordination challenges with the central government. Addressing these issues will require not only regulatory streamlining but also the establishment of innovative governance structures to facilitate smoother implementation. Joint working groups involving representatives of the centre, states, and industry can help address some of these issues.

Risks Associated with PV Modules

Solar technology related risk perceptions have significantly decreased with expanded installations and operational experience. While solar projects involve various components, such as modules, inverters, batteries, and cables, this discussion focuses specifically on risks related to PV modules. There are two key risks to consider: technology risks associated with new PV technology variants and India-specific supply chain risks stemming from regulations that mandate domestic manufacturing of PV modules.

Performance uncertainty in new PV technologies

PV modules degrade n over their lifetime, influenced by various factors such as extreme temperature, heat, humidity, irradiation and mechanical stress. These conditions contribute to a measurable decline in power output over time. Although ongoing advancements in PV technology aim to enhance the operational performance of modules, uncertainty persists, especially with newer untested technologies.

India is transitioning from p-type PERC technology to n-type TOPCon and HJT. While this shift promises performance improvements, they come with risk due to the limited field data available for new technologies, which diverge significantly from previous p-type technology families.

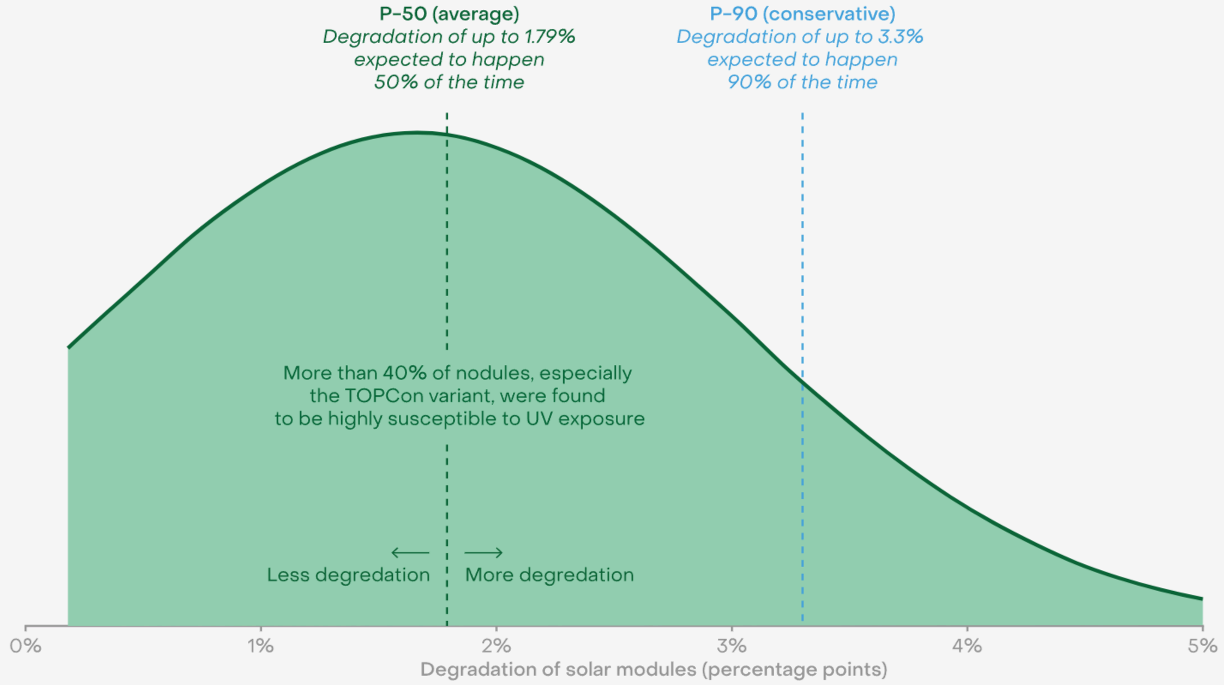
PV modules undergo rapid Light-Induced Degradation (LID) when exposed to sunlight during the first few months of operation, typically resulting in a power loss of 1-2% in the prevalent module types, followed by a more gradual annual degradation rate of 0.4-0.55% over their 25 years life span. These modules typically come with a performance warranty of approximately 25 years.

While product data sheets often showcase competitive module degradation rates, field studies indicate that actual rates are notably higher in India's challenging climatic conditions. High temperatures and humidity levels in India frequently accelerate module degradation beyond internationally accepted benchmarks. Due to limited field data on newer module types, such as TOPCon and HJT, insights from international PV module assessment programs—such as Kiwa PV Evolution Labs (PVEL) and the Renewable Energy Test Center (RETC)—are essential for understanding the quality risks. These programs rigorously test module performance and offer essential testing data to support bankability assessments. This is crucial for projects which use new technologies or source products from new manufacturers.

The 2024 RETC PV Module Index Report emphasises caution regarding TOPCon and HJT module technologies, highlighting their vulnerability to ultraviolet (UV)-induced degradation (UVID). About 40% of these module variants showed greater than 5% performance loss under UVID testing (equivalent to being exposed to 2.8 years under standard field conditions), with some modules experiencing as high as 16.6%. Similar concerns around rapid degradation of TOPCon modules have been raised by universities and other testing labs.

Higher degradation rates for some TOPCon modules warrant careful technology appraisal

Probability distribution of UV induced degradation of solar modules in percentage points



Source: RETC PV Module Index Report, 2024; Sen et al., 2024
The RETC PV Module Testing Program conducts evaluations of modules to simulate real-world field conditions. The UV exposure results from the 2024 program are presented here. UV refers to ultraviolet.

One of the possible reasons for the above observation in new module technologies have been attributed to manufacturers rushing early-stage "beta testers" to market to secure a first-mover advantage. The rate of degradation in TOPCon modules increases significantly due to the presence of humidity and unintentional contamination.

Risks from localisation of PV manufacturing

The government of India has introduced various policies to bolster the presence of a domestic PV manufacturing supply chain, with the dual aim of enhancing energy security and reducing reliance on module imports. In 2022, a basic customs duty

(BCD) of 25% and 40% was imposed on the import of cells and modules, respectively. To further promote localisation, the government implemented the Approved List of Models and Manufacturers (ALMM) regulation in 2024, mandating the use of domestically manufactured modules for utility-scale projects. While these measures are likely to strengthen domestic manufacturing, they also introduce risks around costs and performance.

- **Increasing costs:** One of the key concerns with localisation is the rise in domestic module and cell costs. With the implementation of ALMM, module prices are reported to have increased by 20%. Also, the cost of cell manufacturing in India is presently estimated to be 50% more than imported Chinese cells. Additionally, duties on solar glass and aluminium are expected to further drive up costs. Gradual tightening of mandates aimed at deepening the local supply chain could escalate project costs, ultimately leading to higher solar power tariffs.

  Policy instability, including frequent revisions in tariff structures and regulations, has contributed to cost unpredictability. Instances of PPA renegotiations and project cancellations have already been observed due to reasons associated with changes in the tariff structure.

  Also, the prices of upstream solar panel materials, such as polysilicon and wafers, are significantly influenced by Chinese suppliers. These suppliers have strategically adopted self-discipline practices lately, actively managing production levels to prevent spiralling down of prices due to intense competition. All these factors tend to create considerable uncertainty around the end price of PV panels for project developers.

- **Performance concerns:** Another challenge is ensuring module quality for domestic manufacturers. The rapid expansion of domestic production has attracted inexperienced manufacturers. Their products are likely to face teething troubles and potential quality issues, even with national certification programs in place. Reports from reputed international PV testing agencies like RETC and Kiwa PVEL reveal that only a few Indian manufacturers, such as Waaree, Emmvee, and ReNew, have undergone standardised module testing.

Additionally, shielding the Indian market from advanced technology modules poses an opportunity cost, depriving solar projects from efficiency gains and cost reductions. For instance, while n-type TOPCon technology is becoming increasingly common in China, only 20% of manufacturing lines in India have adopted it, with the majority still relying on the older p-type technology.

Measures to address PV panel related uncertainties

- **Quality assurance:** The Government of India, through the ALMM guidelines, has mandated all PV modules being sold in India to undergo certification by the Bureau of Indian Standards (BIS), a national organisation responsible for product standardisation and quality assurance. The National Institute of Solar Energy (NISE) serves as the government's nodal laboratory for testing PV cells and modules. To bolster the credibility of these testing procedures, it is crucial to align domestic laboratory capabilities with stringent international testing standards.

  Greater transparency can be achieved by publicly disclosing reports of specimen tests conducted on modules from various manufacturers. Recognising the importance of reliable product standards for bankability, leading private manufacturers like Waaree Energies have also established private testing facilities to instil greater confidence among developers and investors.

- **Sunset clauses for infant industry protection policies:** The government should consider avoiding shielding the industry from foreign competition indefinitely. As the sector matures and gains experience, it should be encouraged to compete on a level playing field. To support this shift, regulations like ALMM should include sunset clauses, providing clear timelines and visibility for both manufacturers and developers. This approach can reduce uncertainties surrounding costs and quality while setting well-defined targets for domestic manufacturing.

Risks associated with generation shortfall

RE power generation is inherently variable and intermittent, making it challenging to accurately predict electricity output from solar plants or wind turbines. This uncertainty creates risks at two levels. First, if aggregated generation (e.g., monthly or annual output) falls below estimated levels—often due to resource estimation errors or prolonged periods of unfavourable weather conditions—it directly impacts the revenue anticipated over the project's lifetime. Second, in India, generators are required to adhere to scheduled power delivery within specific time blocks throughout the day. Deviations trigger penalties under the Deviation Settlement Mechanism (DSM), which increases operational costs. The DSM ensures grid stability by creating a financial reserve for backup power generation to compensate for last-minute shortfalls.

Risks associated with chronic underperformance

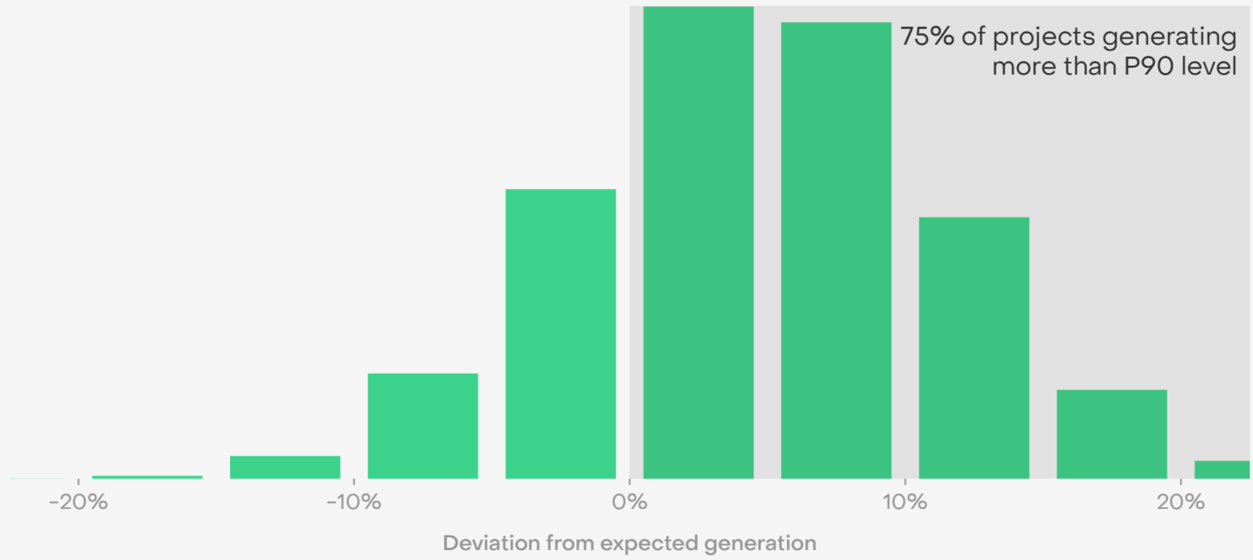
Systemic underperformance of RE projects can occur when solar irradiation or wind speeds fall short of projections. Even when average irradiation or wind speeds align with projections, factors such as prolonged cloud cover, fog, poor air quality, and inadequate operation and maintenance practices can negatively impact generation profiles. This can result in generation falling short of expectations, leading to setbacks in meeting supply commitments and facing penalties.

The availability of long-term historical weather data in developing countries like India is often limited, lacking the hyperlocal granularity required for site-specific weather forecasting. Large-scale, sporadic mapping of solar and wind potential further complicates accurate resource estimation. The widespread absence of ground-mounted weather measurement systems increases uncertainty in RE generation profiles.

To assess underperformance related risks, the gap between actual and expected electricity generation in 2023 was analysed for 24 PV plants across states, totalling a cumulative capacity of approximately 5 GW. Expected generation levels were based on P90 estimates, which represent the minimum generation a project is expected to achieve 90% of the time, a crucial parameter for debt servicing. By comparing actual generation with P90 estimates, we estimate a measure for underperformance for solar projects in India.

75% of solar plants in India exceed their generation commitments

Probability distribution of solar plants based on the percentage deviation between actual and expected P90 generation levels in 2023



Source: Central Electricity Authority
Minimum expected generation is determined using the reported P90 estimates in credit rating reports for individual solar projects. The analysis covers 24 projects, totaling 5GW.

This analysis shows that more than 75% of the surveyed solar projects generated at or above their P90 estimates, indicating a healthy trend for the projects' ability to service debt. Instances of significantly lower generation than P90 estimate were rare, emphasising the overall healthy generation profile of solar projects in India and their reduced risk for lenders.

However, some limitations exist in generalising the findings. The absence of multi-year annual time series data for several plants means that deviations observed in 2023 may reflect anomalies caused by poor local weather conditions or downtime due to technical issues rather than long-term trends. Furthermore, this analysis does not consider P50 or P75 generation levels, which are often of greater relevance to equity investors. This analysis does not account for the underperformance of wind projects in India. Industry stakeholders have frequently highlighted the chronic underperformance in wind projects, with a significant number failing to meet their debt service obligations.

Risk associated with widening DSM penalty

The Deviation Settlement Mechanism (DSM) is a regulatory framework introduced by the Central Electricity Regulatory Commission (CERC) to maintain grid stability by managing deviations from scheduled electricity generation or consumption. This system incentivises grid participants to adhere to their planned schedules through a combination of penalties and compensations.

A dispatch schedule refers to the planned amount of power that a generator commits to supply, or a consumer commits to draw during a specific time period, typically in 15-minute blocks. Maintaining these schedules is critical for balancing supply and demand, ensuring the grid operates at a stable frequency. Deviations from these schedules can disrupt this balance: if load exceeds generation, the frequency dips, risking grid instability and outages; if generation exceeds load, the frequency rises. A synchronised operation of the grid relies on maintaining a consistent frequency (~50.0 Hertz in India) , ensuring all generators operate in sync for stable and efficient power delivery.

Under DSM regulations, penalties apply to generators for under-injection (delivering less power than committed), while over-injection receives reduced or no compensation. The severity of these penalties and reductions escalates with the magnitude of deviation, thereby encouraging grid participants to align their actual performance with their schedules.

RE generators face unique challenges due to weather-dependent uncertainty. Advanced forecasting tools and storage solutions are required to minimise deviations and avoid penalties under DSM regulations.

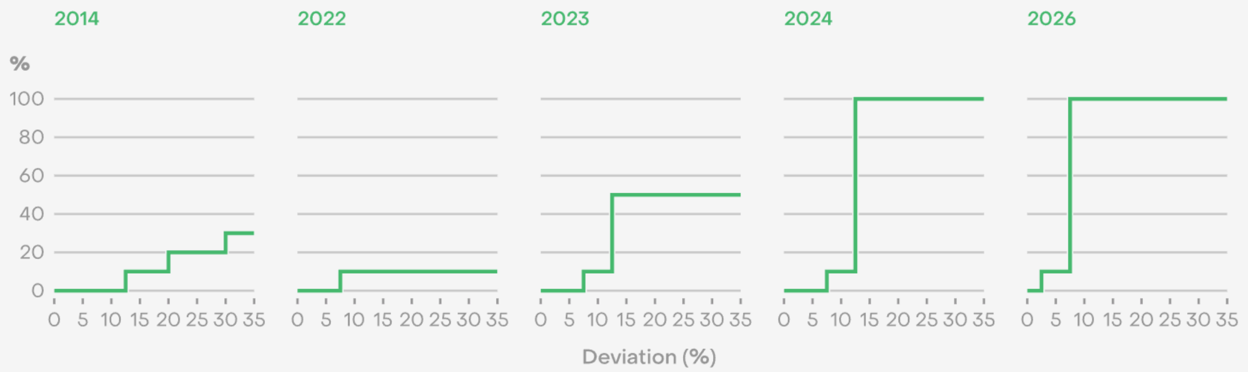
Historically, DSM regulations were more lenient toward solar and wind generators due to their weather-dependent nature. Recognising the inherent variability in their output and the challenges in forecasting, these generators were subject to less stringent penalties compared to dispatchable sources like coal and gas. However, over time, DSM regulations for RE generators have become progressively stricter, with key observable trends:

DSM regulations for RE generators have become progressively stricter over time with some key observable patterns:

- **Tighter deviation bands:** The allowable range of deviation for which a RE generator is not penalised has narrowed significantly.
- **Increased penalties:** The penalties for under-injection have risen, while compensation for over-injection has been reduced or eliminated entirely in a certain range of over-injection.
- **Stricter rules for renewable generators:** RE generators are now increasingly held to stricter generation forecasting standards, aligning them more closely with dispatch characteristics of conventional power plant

In India, penalties for schedule deviations have become stricter over time, with risks of further tightening

Penalty for solar under-generation as a percentage of the electricity sale price under different DSM regulations for different deviation levels.



Source: Central Electricity Regulatory Commission
Deviation Settlement Mechanism (DSM) rules regulate penalties and compensations for power generation deviations from scheduled quantities to ensure grid stability and discipline. Contracted rate refers to the tariff for sale or purchase of power. In the power sector, a schedule refers to the declared generation or consumption of electricity submitted in advance to the grid operator, which must be followed to maintain grid stability

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These evolving regulations do not only affect new RE generators but also existing projects, many of which were developed under more lenient DSM frameworks.

As a result, generators that did not anticipate these regulatory changes during their initial planning are now facing higher-than-expected penalties, adding an additional layer of financial uncertainty.

Looking ahead, DSM regulations are likely to become even more stringent. The shift from 15-minute accounting blocks to 5-minute blocks could increase penalties, as shorter intervals are more prone to fluctuations. The retrospective application of DSM rules also adds to the uncertainty in project planning.

The revenue loss on account of the DSM regulations could be between 1.5%-2% on average as per the pre-2024 DSM rules. Ember's modelling estimates are based on deviation data from solar and wind power plants in the Northern and Western regions. Our estimates suggest that the expected losses due to deviations could increase by 60-70% with the onset of the new DSM regulations, set to take effect from December 2024. Furthermore, with the bands already announced to become even stricter in early 2026, our analysis suggests that DSM losses could become 2x pre-2024 levels, significantly increasing revenue losses for RE generators.

Measures to address generation shortfall related issues

- **Improved data collection and forecasting:** Generation data from long-operating projects has significantly enhanced the understanding of regional generation profiles. Efforts to collect site-specific data in key solar regions have intensified, driven by the need for more accurate generation estimates. The Indian government's proposal to mandate renewable developers to install on-site weather systems underscores this push for improved forecasting and high-quality data collection.

- **Improving operation and maintenance:** Advancements in operation and maintenance (O&M) practices, such as robotic cleaning and advanced monitoring techniques, have contributed to ensuring generation reliability. Innovations like weather-indexed insurance products further provide financial security against generation shortfalls caused by unexpected weather events or natural disasters, enhancing developers' financial resilience.

- **Integrating storage for minimising DSM penalty:** Risks associated with DSM penalties can be significantly mitigated by integrating variable RE with storage capacity. Storage provides critical support by discharging energy when generation is lower than scheduled and strategically charging when generation exceeds expectations. Even a modest amount of storage can substantially reduce DSM charges. The feasibility of integrating storage improves as DSM penalties become stricter or battery costs decline—both of which are likely in the near future. The government is also expected to mandate small storage capacity alongside solar projects.

  However, it is crucial to evaluate whether generators can operate under stricter DSM penalties while remaining financially viable. Penalties should be tightened only after considering various project-related aspects, and ongoing technological trends such as declining battery costs should inform policy decisions.

- **Different regulations for PPA and merchant capacity:** The ability to adjust schedules plays a critical role in managing the uncertainty of RE generation. PPA-based renewable capacity have greater flexibility to revise their schedules multiple times throughout the day after submitting the initial schedule one day in advance. In contrast, exchange-based "merchant" capacity, which sells electricity on the wholesale electricity market, is not permitted to make revisions to its schedule and must strictly adhere to the initial schedule. This lack of flexibility makes it more challenging for merchant capacity to adapt to generation fluctuations, thus increasing the risk of penalties. Therefore, considerations around whether the same level of strictness should apply to both models should be discussed, particularly if wholesale market-based transactions are to be encouraged.

Risks associated with new-age FDRE tenders

Firm and Dispatchable Renewable Energy (FDRE) tenders are procurement mechanisms designed to ensure the deployment of RE and storage that delivers demand-aligned power. These tenders address the variability and intermittency challenges of RE sources by encouraging developers to complement solar and wind dispatch with storage solutions. By aligning RE generation with specific load patterns, FDRE tenders shift the traditional energy buyer-supplier dynamic from a "use what is offered" to a "get what they need" model.

By design requirement, FDRE projects tend to be oversized beyond the minimum necessary contracted capacity. Developers also leverage the power market to buy a limited portion (~5%) of electricity during shortfall and sell excess generation. New segments like the Green Day Ahead Market (GDAM) have been introduced to facilitate exclusive RE trading.

FDRE projects come in various forms, all sharing the common goal of addressing the intermittency of RE. The difference lies in tender conditions which specify certain demand fulfilling conditions, minimum storage capacity requirement, or the quantity of power that needs to be delivered at certain time stamps through the day. The 2022 Ministry of Power guidelines provides an overview of the process for procuring dispatchable RE under tariff-based competitive bidding. This mandates designing projects in a way that would meet 90% of the buyer's monthly demand profile.

FDRE projects introduces three unique kind of risks:

- **Risk of not meeting demand fulfilment targets:** Failing to meet the Demand Fulfilment Ratio (DFR- explained below) targets can lead to penalties and revenue losses. Until the initial projects are successfully established, the risk of non-compliance with demand obligations remains significant, potentially resulting in financial setbacks for developers.

- **Exposure to power market volatility:** Our modelling estimates indicate that excess capacity from oversizing in FDRE projects could range from 25% to 45% of contract requirement, making a significant portion of revenues generated subject to market fluctuations. Excess dependence on power markets introduces uncertainty in revenue realisation. First, revenue uncertainty can arise on an aggregate basis due to the inherently volatile nature of power markets. Second, with the increasing penetration of solar energy into the generation mix, instances of price cannibalisation can occur—a market condition where an oversupply of electricity significantly drives down market prices. While this phenomenon has been observed occasionally in Indian power markets, it is expected to become more prevalent as the share of renewables continues to grow.

- **Technology uncertainties in battery cost and performance:** Uncertainty in battery cost decline affects replacement expenses and overall project costs. Additionally, degradation, round-trip efficiency, and depth of discharge impact operational and financial viability.

These risks associated with FDRE projects are explored in detail in the following sections.

Risk of not meeting stipulated demand

FDRE projects are required to adhere to specific demand profiles as outlined in the tender requirements. The FDRE capacity must ensure that demand is met as per these requirements, and any failure to do so is expected to result in penalties.

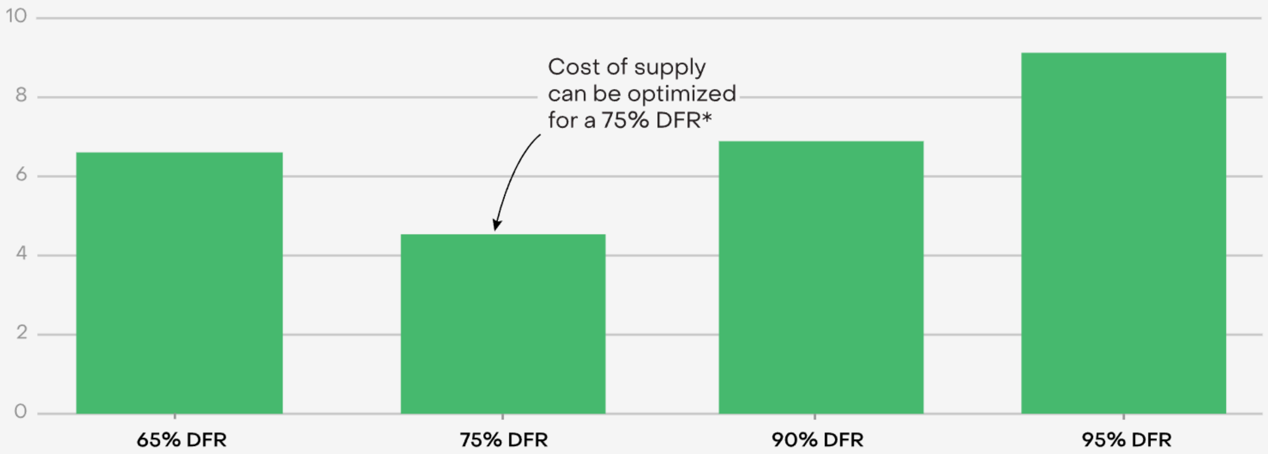
The DFR for each 15-minute time block is determined as the ratio of the scheduled power injection to the demand specified by the buying entity, with a maximum value capped at 1. To assess performance, shortfalls are aggregated against the 90% DFR threshold, as defined in the tender, across all time blocks within a contract month. If the DFR falls below 90%, a penalty of 1.5 times the PPA-discovered tariff is imposed per unit of shortfall.

To mitigate shortfalls, developers are permitted to procure up to 5% of the deficit from wholesale markets. However, beyond this limit, they must rely on their own generation assets to maintain the DFR.

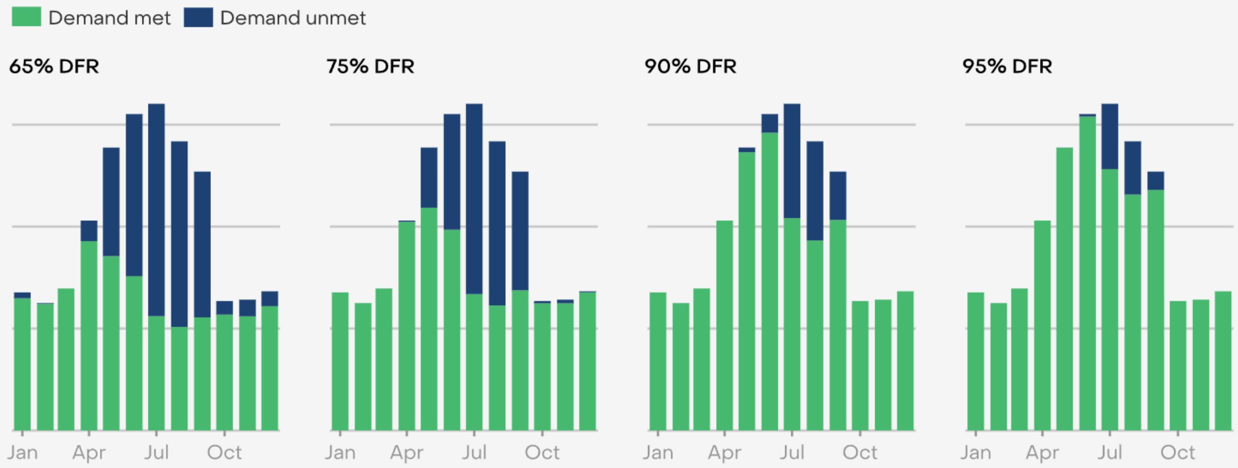
Achieving 90% DFR or more is costly due to oversizing of the generation capacity and increased storage requirements. A more optimal strategy may involve designing systems to achieve a slightly lower DFR and accepting penalties for occasional shortfalls. This was modelled to understand what DFR values optimise the overall cost structure of electricity, inclusive of penalties (referred to as the “cost of supply” in the figure below). Ember’s estimates, based on the SECI-FDRE-IV 1260 MW tender and prevailing market conditions, suggest that an optimal DFR of ~75% minimises the cost of supply. However, this figure may vary depending on the specific conditions outlined in tenders.

Optimising for dispatchable RE requirements may involve not fully meeting the total demand

Variation of cost of supply for different DFRs (Rs/kWh)



DFR can be visually represented by



Source: As per Ember's analysis of the SECI-FDRE-IV 1260MW tender · The Demand Fulfillment Ratio (DFR) is the ratio of the actual renewable energy supplied by the generator to the contracted demand profile specified in the Power Purchase Agreement (PPA). DFR below 90% entails penalties as per the tender.
*Cost of supply refers to the generation and storage cost and includes the penalty of not meeting DFR threshold.
FDRE refers to Firm & Dispatchable RE

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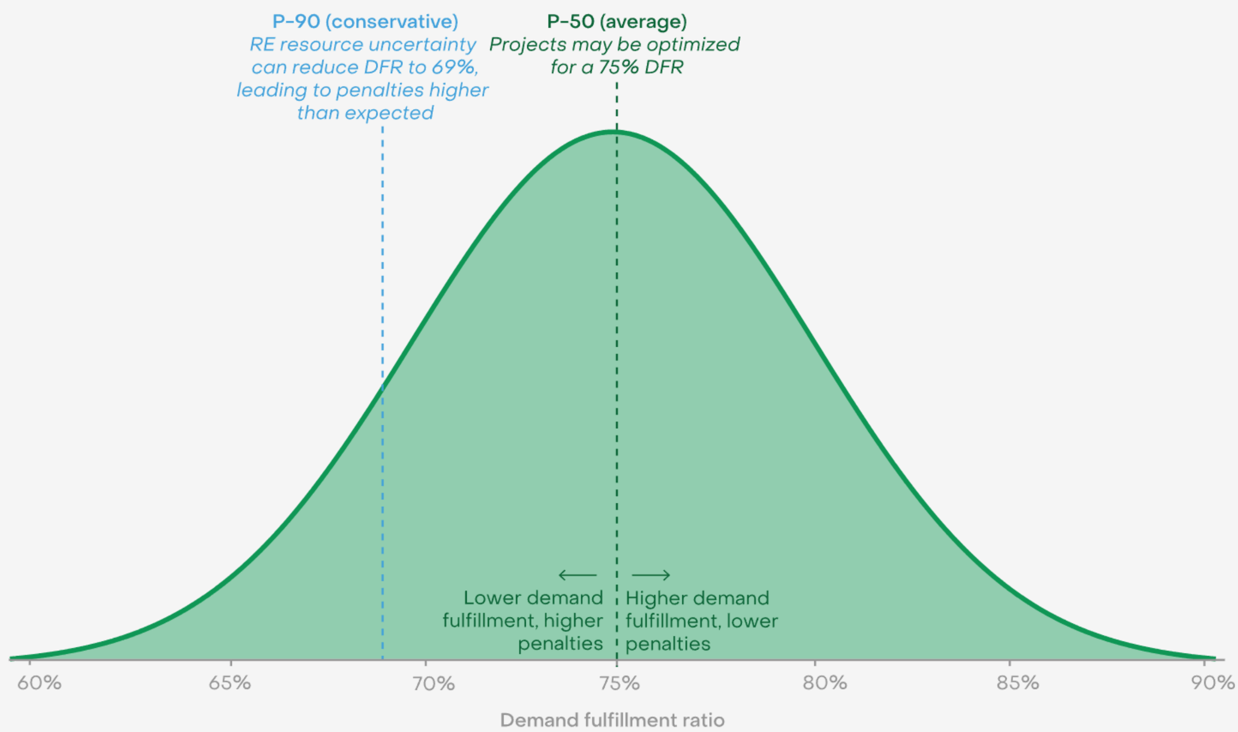
However, even with an optimal project design (75% DFR as suggested by our model) uncertainty persists around meeting targets due to the inherent variability of RE generation. Our analysis, based on historical variability in solar and wind generation, indicates that a system designed for a 75% DFR could experience actual DFRs as low as 69% under extreme weather conditions. This shortfall could lead to penalties exceeding initial projections.

Variability in RE generation can result in higher penalties than expected due to DFR shortfall

Probability distribution of DFR in FDRE projects



Source: As per Ember's analysis of the SECI-FDRE-IV 1260MW tender · The Demand Fulfillment Ratio (DFR) is the ratio of the actual renewable energy supplied by the generator to the contracted demand profile specified in the Power Purchase Agreement (PPA). *DFR below 90% entails penalties as per the tender. FDRE refers to Firm & Dispatchable RE.

FDRE tenders typically mandate a significant share of wind generation to complement solar and meet evening demand, as per tender specifications. However, chronic wind underperformance, as noted by industry stakeholders, makes achieving target DFRs challenging. Additionally, the high cost of storage capacity limits its share in FDRE projects, reducing flexibility in managing variable RE generation.

Risks associated with power market exposure

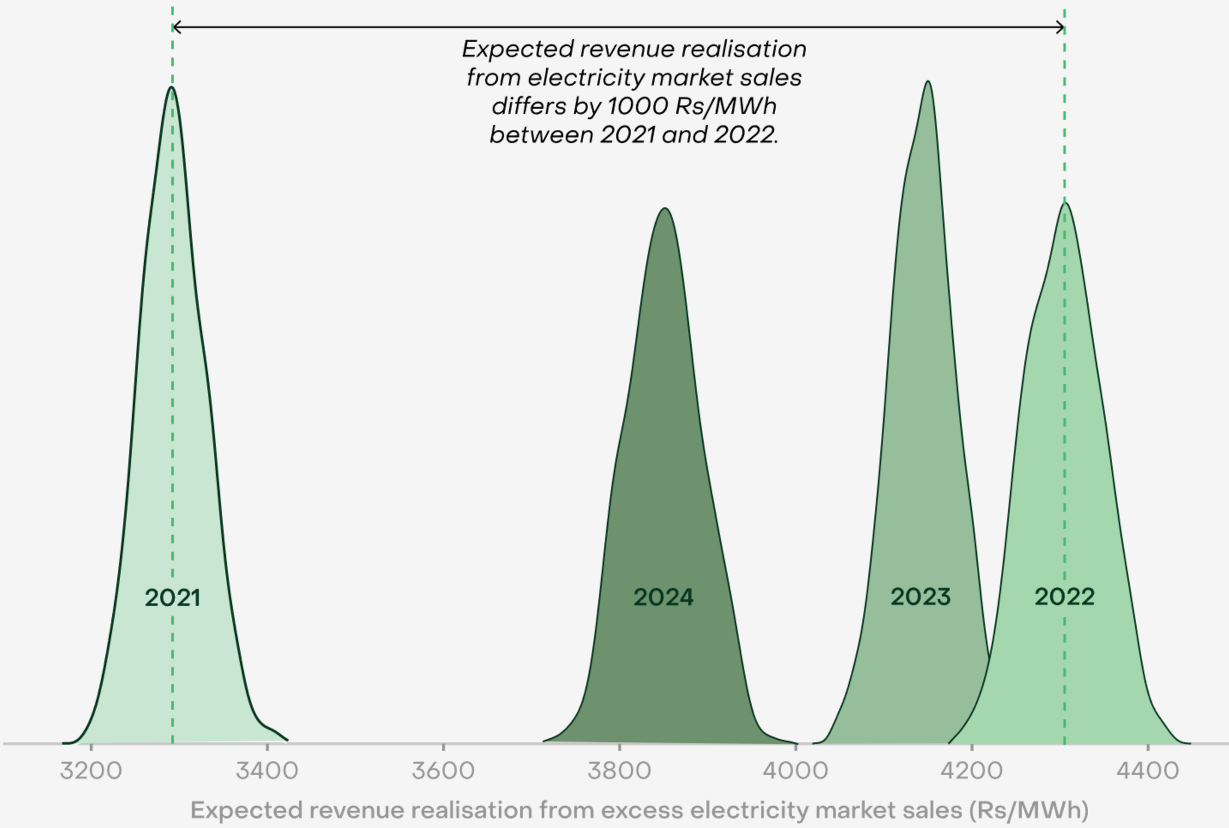
Two critical risks—market volatility and price cannibalisation—significantly affect FDRE projects due to exposure to the wholesale electricity market.

- **Market Volatility:** The inherent volatility of the wholesale electricity market poses significant risks to revenue realisation for projects reliant on revenue from power markets, such as FDREs, even if price cannibalisation due to solar generation is kept under control. This volatility is reflected in the substantial variability in the Market Clearing Price (MCP) during solar hours (9 AM–5 PM) over recent years.

  Ember's assessment shows that excess generation from FDRE projects could range from 25%–45%, making it highly vulnerable to market prices. To better understand the risk associated with selling excess electricity generated by FDRE projects, we analysed the revenue realised per unit of electricity sale in the Day-Ahead Market (DAM) of the Indian Energy Exchange (IEX) from 2021 to 2024. This analysis assumes that surplus electricity was sold in the market during solar hours across these years. The results indicate that the average revenue per unit from the sale of excess electricity varied by approximately ₹1/kWh, with the largest fluctuations observed between 2021 and 2022. This variation underscores the potential revenue uncertainty that FDRE project developers face when relying on market sales for surplus power. In a conservative case, we estimate that overall revenue could be 7%–13% lower due to this volatility.

Expected revenue from electricity sales from solar in the wholesale market has been volatile

Distribution of expected revenue realization from excess electricity market sales (Rs/MWh)



Source: Ember's analysis of revenue realization from the sale of excess generation in the wholesale electricity market from FDRE (Firm and Dispatchable Renewable Energy) projects. · Variations in annual revenue realization stem from differing capacities of solar, wind, and storage in FDRE projects and the time period of excess electricity generation. Prices are based on IEX data for respective years.
FDRE refers to Firm and Dispatchable RE

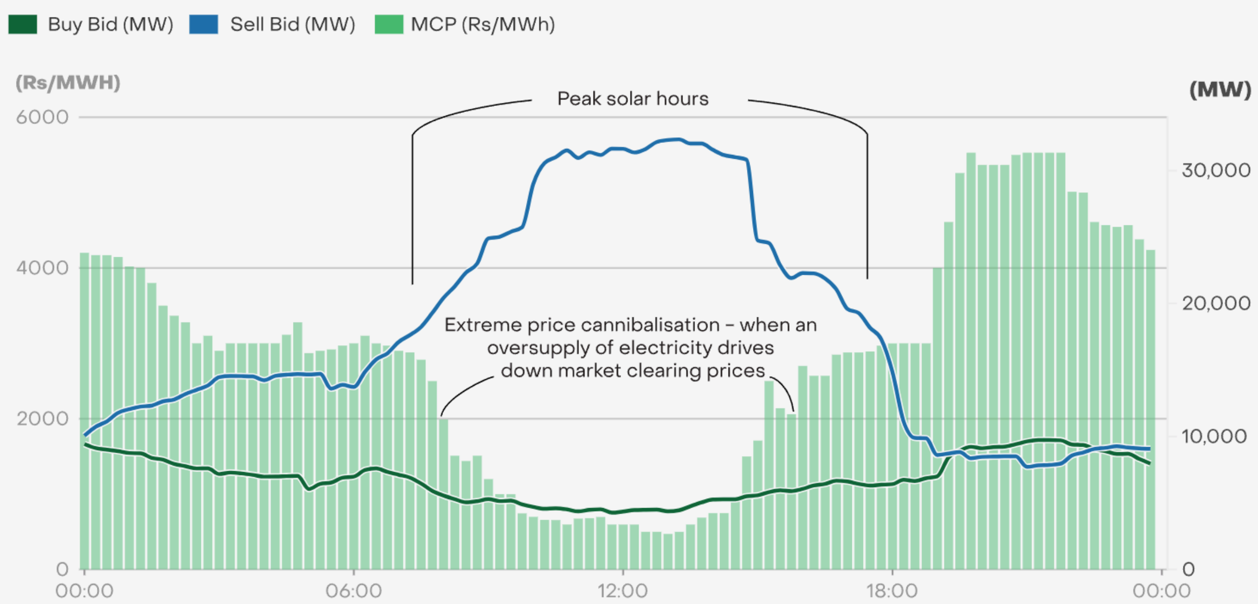
- **Price Cannibalisation:** Price Cannibalisation occurs when an oversupply of electricity during high solar generation periods lowers market prices, reducing revenue for all generators, especially those relying on excess generation sales, such as FDRE projects. This issue has already begun to manifest in the Indian wholesale electricity market. For instance, on August 23, 2024, a day with high solar penetration, prices dropped significantly during solar hours, highlighting the growing impact of cannibalisation.

A key metric for understanding the financial impact of selling excess electricity in the market is the capture rate. Specifically, the solar capture rate is an important indicator that measures the percentage of the solar capture price relative to the average price of the Day-Ahead Market (DAM) over a given time period, such as a year. Essentially, the solar capture rate quantifies how well a solar generator captures value compared to the overall market price. As RE penetration increases, capture rates have exhibited a declining trend in many European countries, signalling lower earnings per unit of electricity generated during peak solar hours. This occurs due to the price cannibalisation effect, where higher renewable supply during sunny or windy periods leads to lower market prices.

As solar capacity in India continues to expand, price cannibalisation is expected but not guaranteed to intensify. Without effective intervention, it could lead to prolonged periods of low market prices during high solar generation hours. If price cannibalisation does intensify, it may erode revenue for RE projects participating in wholesale electricity markets.

India has started witnessing instances of price cannibalisation during solar hours in its wholesale electricity market

Total Buy and Sell Bids (MW) and MCP (Rs/MWh) for Each 15-Minute Settlement Period on August 23, 2024



Source: Data from IEX Day-Ahead Market
Market Clearing Price (MCP) refers to the price at which supply equals demand in a competitive market, ensuring all buyers willing to pay this price and all sellers willing to accept it can trade.

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The core issue, however, lies in the uncertainty surrounding the extent of price cannibalisation. A conservative investor may plan for the worst-case scenario, assuming intensified cannibalisation, which could influence project design, pricing strategies, and investment decisions.

Measures to deal with power market uncertainty

- **Contracts for Difference (CfDs):** CfDs are financial agreements that provide revenue stability by guaranteeing a fixed "strike price" for electricity. When market prices fall below the strike price, the generator is compensated for the difference, and when market prices exceed the strike price, the generator pays back the surplus. This mechanism shields RE projects from the volatility of market prices, ensuring predictable revenue streams.

  The UK has demonstrated the effectiveness of CfDs since the Electricity Market Reform (EMR) in 2013. By 2023, CfD auctions in the UK had successfully contracted over 20 GW of renewable capacity, covering technologies such as offshore wind, onshore wind, solar PV, and biomass. The scheme has also driven significant cost reductions and market efficiencies.

- **Investing in more storage capacity:** As storage technologies become more cost-effective, investors are likely to integrate additional storage capacity into their RE projects. Storage could play a crucial role in mitigating price risks by enabling generators to store excess electricity during periods of low market prices and release it when prices are higher. This ensures better revenue realisation and reduces the impact of price cannibalisation on RE project returns.

  In FDRE tenders, investing in more storage capacity can also reduce the need for oversizing. By aligning generation and demand more efficiently, additional storage minimises the amount of excess electricity exposed to the volatility of wholesale electricity market prices.

Risks around battery replacement costs and battery performance

Battery storage is expected to play an increasingly significant role in FDRE tenders. In most FDRE tenders, the minimum storage requirement was set at 25% of the contracted capacity (e.g., 25MWh for 100MW), the battery cost component constituted around 2% - 2.5% of the total project capex, as per our estimates. However, newer tenders now specify much higher storage capacities. For example, the SECI-ISTS-XVII tender for 2000 MW ISTS-connected solar PV coupled with 1000 MW/4000 MWh energy storage, translates to a minimum storage capacity of 200 MWh for every 100 MW of contracted capacity. In such cases, the capital cost contribution of Battery Energy Storage Systems (BESS) could rise significantly, reaching 32%–38% of the total project cost.

This increase highlights the critical importance of battery pack cost declines in the lifetime of a 25-year FDRE project. Batteries typically need to be replaced within 10–12 years, and investors must factor in replacement costs while bidding for such tenders. The battery pack, which constitutes 50%–60% of the total battery system cost (with the remainder including EPC, BoS, land, etc.), becomes a key driver of overall costs. For instance, battery pack costs are projected to reach USD 64/kWh by 2030 (as per Goldman Sachs) or USD 80/kWh by 2030 (as per BloombergNEF). If actual costs remain higher or decline at a slower pace by the replacement year, we estimate this could lead to up to 100 bps increase in the total capital costs of the project.

Other potential project risks

Counterparty Risk Due to Non-or-Delayed Payment

Distribution Companies (DISCOMs) in India are regulated entities responsible for purchasing power from electricity generators, transmitting it through the grid, and distributing or reselling it to end consumers at regulated tariffs. DISCOMs pay for the power they purchase and transmit, and they rely on revenue collection through consumer tariffs and, to some extent, government subsidies, to cover their operational costs and earn a return on their investments. They play a crucial role as the primary interface between utilities (generation and transmission) and end consumers, managing a significant portion of all electricity transactions. As the "cash register" of the power sector, DISCOMs are responsible for collecting revenue critical to sustaining the electricity value chain, including payments to generators and transmission companies, as well as investments in distribution infrastructure.

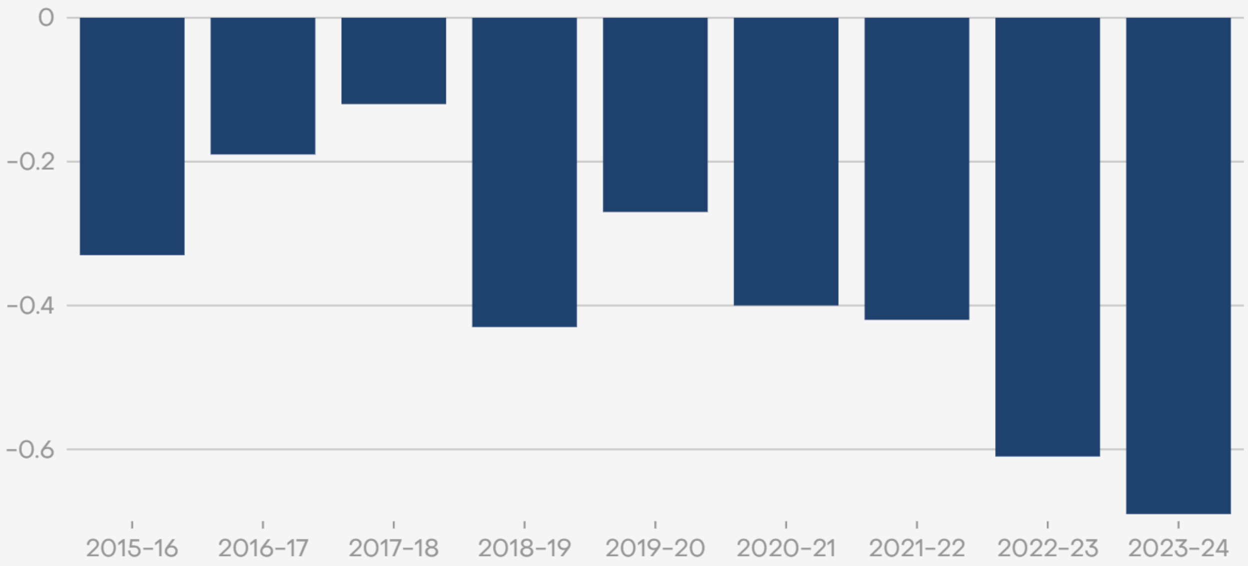
Despite their central role, DISCOMs face chronic financial difficulties due to several factors:

- Inefficiencies in revenue recovery and billing processes.
- Delays in government subsidy disbursements.
- High dependence on short-term borrowing to address cash flow gaps.
- Rising power supply costs due to expensive power purchase agreements and operational inefficiencies.

On average, DISCOMs lose ₹0.55 (FY23 cash adjusted ACS-ARR gap) for every unit of electricity sold. These losses have resulted in an accumulated debt of ₹6.84 lakh crore, a figure which stands substantial when compared to India's GDP of ₹160 lakh crore in FY 2023-24. To cope with financial strain, DISCOMs often delay payments to power generators, and take on additional debt.

Indian DISCOMs have struggled to recover cost, more so in recent years

Difference between revenue and cost per unit of electricity sold (Rs/kWh)



Source: India Climate & Energy Dashboard · The data represents the gap between Average Cost of Supply (ACS) and the Average Revenue Realized (ARR) on an aggregate national level basis
DISCOMs in India stands for Distribution Companies, referring to utilities responsible for distributing electricity to consumers within a region.

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The financial distress of DISCOMs creates significant uncertainty around their ability to make timely payments to electricity generators, including RE developers. This uncertainty gives rise to counterparty risk, the likelihood that a DISCOM will default on or delay its payment obligations.

The Ministry of Power introduced the Late Payment Surcharge (LPS) mechanism to address payment delays and enhance financial discipline among DISCOMs. This framework includes payment security mechanisms like Letters of Credit (LCs), power supply regulation for defaults, restrictions on accessing power exchanges, incremental penalties for repeated defaults, and installment-based payments to ease financial pressure on DISCOMs.

Since its implementation, the LPS mechanism has reduced unpaid dues significantly, from ₹1.4 lakh crore in June 2022 to ₹48,000 crore in February 2024, highlighting its effectiveness. However, the persistent financial losses of DISCOMs continue to pose risks of payment defaults. While the LPS mechanism has mitigated counterparty risk to an extent, deeper structural reforms are essential for ensuring DISCOMs' long-term financial stability.

Risk related to curtailment

Curtailment of generation in RE projects, particularly wind and solar, has historically posed challenges in India, despite regulatory measures to minimise it. The 'must-run' status, established under the Indian Electricity Grid Code 2010 and the Electricity Act 2003, prohibits curtailment for commercial reasons.

However, curtailment issues persisted, with Tamil Nadu and Gujarat reporting curtailment rates of 20% and 11% respectively in 2017-2018. These high levels of curtailment led to interventions by the Appellate Tribunal for Electricity (APTEL) and discussions on clearer protocols, thresholds, and compensation mechanisms.

The Electricity (Promotion of Generation of Electricity from Must-Run Power Plant) Rules, 2021, reinforced the must-run mandate, permitting curtailment only for technical or grid security reasons. The rules also required compensation for generators affected by curtailment and introduced provisions for selling excess power in the market, creating a revenue adjustment mechanism for unused energy.

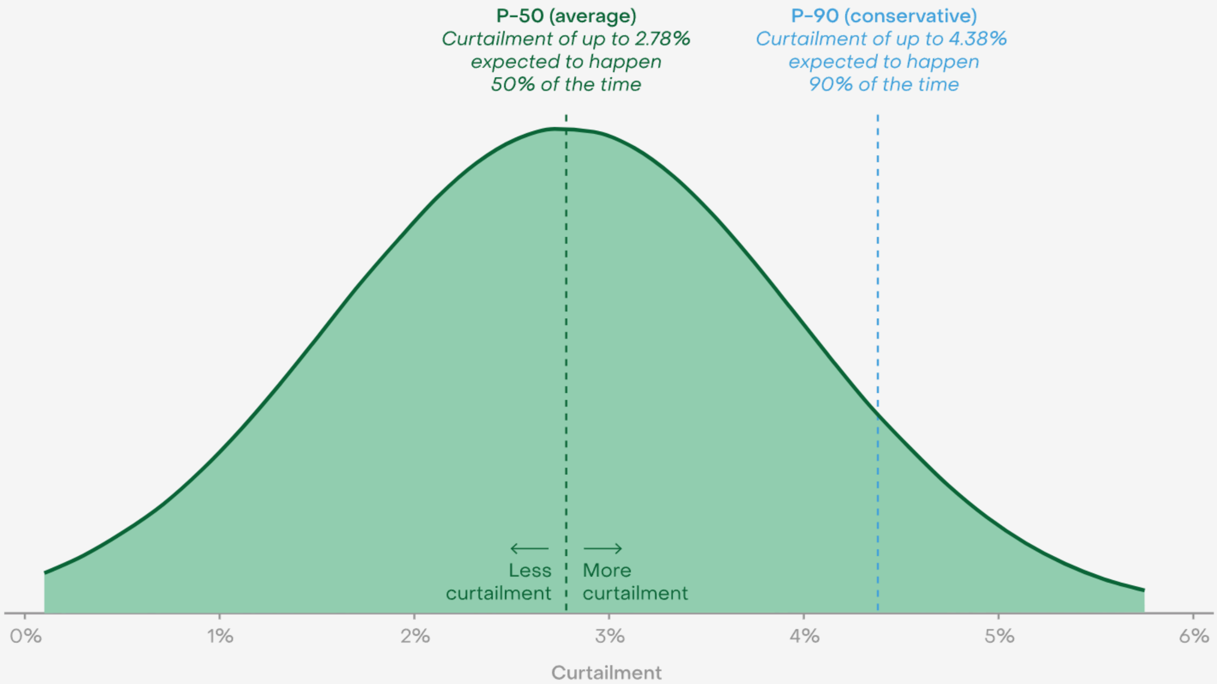
In recent years, curtailment incidents have declined, though isolated cases still occur. Moreover, the planned expansion of RE capacity could strain the grid's ability to absorb variable and intermittent RE, potentially increasing curtailment rates. However, global experience indicates that greater penetration of variable RE can be managed effectively with strong regulations and grid upgrades, avoiding significant increases in curtailment.

In India, SECI's tender specifications provide compensation for curtailments exceeding 175 hours of reduced off-take and 175 hours of grid unavailability. The regulatory framework seeks to keep curtailment within acceptable limits and compensate fairly when these thresholds are exceeded. However, uncertainty exists regarding whether grid unavailability will reach the 175-hour threshold or be significantly lower, whether reduced off-take will occur, the timing of such events (e.g., coinciding with peak solar generation), and the feasibility of selling excess power in the wholesale electricity market.

To assess these uncertainties, a Monte Carlo simulation (see methodology for curtailment related risks) is conducted using an assumed probability distribution for the occurrence of either reduced off-take or grid unavailability below the specified thresholds. This analysis estimates a probabilistic curtailment of approximately 2.75%, with a more conservative P90 estimate at around 4.7%.

Uncompensated curtailment is expected to be around 3% but could be as high as 4.5% under current rules

Probability distribution of possible curtailment in solar projects (%)



Source: Ember's analysis uses a Monte Carlo simulation to assess uncompensated curtailment under current regulations. The figure illustrates probabilistic curtailment under these rules, not historical data. Uncompensated curtailment occurs when generators face reductions in power generation without reimbursement.

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Refinancing risk

The process of obtaining clearances and setting up a solar project involves significant risks. However, once a developer successfully establishes an operational project, they can pursue refinancing. Refinancing allows developers to secure a new loan with better terms, as the project is now de-risked and operational.

There are multiple refinancing options available for solar projects. Developers can access debt at more favourable terms from banks or NBFCs and issue bonds to raise capital. Additionally, RE projects can be sold to infrastructure investment trusts (InvITs) to recycle capital, although this is not strictly a refinancing process. These mechanisms provide opportunities to optimise the project's financial structure and improve cash flow.

Refinancing has become a standard practice for solar projects; however, there is uncertainty around the rates at which it can be secured. Factors such as the project's generation performance, timely payments from off-takers, and the ability to manage variability through power markets play a crucial role in determining refinancing terms. Effective refinancing can deliver significant financial benefits by extending loan tenors and reducing lending rates by 50 to 200 basis points.

Equity sponsor related risk

The cost of capital for RE projects varies depending on the equity sponsor, who is responsible for executing and managing the project. Experienced developers or those backed by large Indian conglomerates tend to secure loans at more competitive rates due to their proven track record and credibility. In contrast, newer or inexperienced companies are considered riskier, leading to a higher cost of capital for their projects. The entry of Indian public sector companies like NTPC and ONGC into the RE sector is expected to lower the cost of capital, as their strong financial backing and reputation instil greater confidence among lenders.

Summing up: How various risks affect the cost of capital and what can be done?

As discussed, various risks contribute to uncertainties in revenue generation and operational costs for RE projects, directly influencing the cost of capital. A clear understanding of these risks is essential for devising strategic mitigation measures. This section outlines how different risks aggregate and suggests potential strategies to mitigate the major risks.

Up to 300 bps increase in cost of capital expected due to FDRE related risks alone

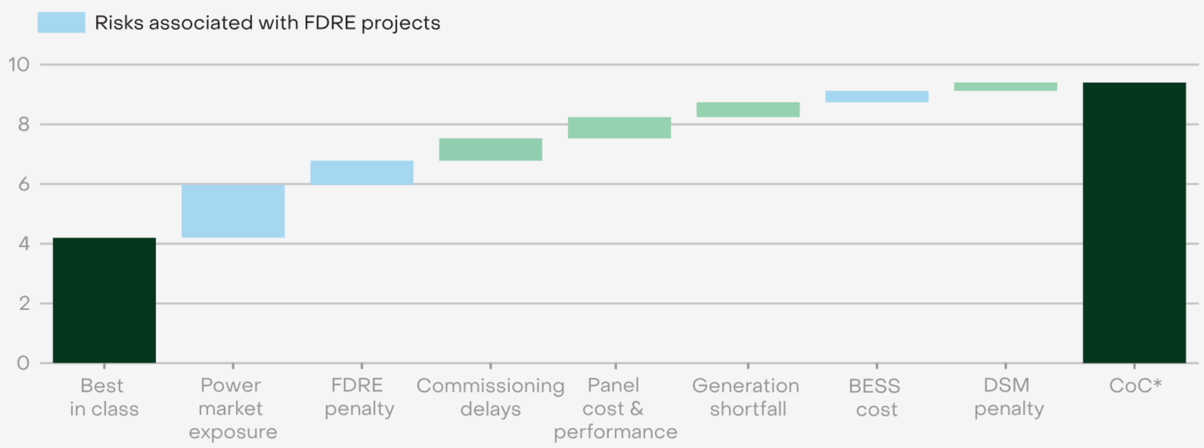
The figure below illustrates the modelled risk premium for various project risks, showing their impact on the overall cost of capital (CoC). Current trends indicate that commissioning delays and new-age FDRE projects are among the most significant contributors to the overall risk profile. Using a build-up method for these assessed risks, the estimated CoC stands at approximately 9.4%. This analysis applies P90 estimates for various risk categories to determine corresponding risk premiums, representing the perspective of an extremely risk-averse lender. In practical evaluations, actual risk premiums are likely to be lower than those derived here as risk attribution and perception vary among lenders and investors.

The entire spectrum of risk lies between the P50 and P90 scenarios, with the final assessment often relying on judgment calls. Additionally, macroeconomic factors such as exchange rate fluctuations and inflation also play a significant role in shaping financing conditions. However, this research does not aim to determine an exact cost of capital (CoC) for Indian renewable projects but rather to develop a more quantitative understanding of contemporary project-related risks and their impact on financing decisions.

Based on insights from primary interviews and secondary literature, the current CoC for conventional RE projects in India is estimated to range between 10-12%.

New-age RE projects are expected to significantly drive the cost of capital

Premiums calculated for various risks in percentage points



Source: Ember's analysis on individual risks. New Age Firm and Dispatchable RE (FDRE) projects incorporate variable RE capacity with integrated storage to incorporate dispatchability. · BESS refers to Battery Energy Storage System. DSM refers to Deviation Settlement Mechanism. *Cost of Capital (CoC) is derived using the buildup method, and excludes some project-specific or macroeconomic risks, and may therefore be underestimated.
Best in class refers to RE projects with the lowest CoC, adjusted for India's country risk premium obtained from secondary sources.

A key takeaway from this analysis is that FDRE projects introduce new risks that are not yet reflected in prevailing lending rates. While commissioning delays have long been a concern, FDRE projects present additional uncertainties. Our assessment suggests that the combined effect of heightened commissioning delays and FDRE risks could lead to a 300-400 bps increase in the CoC. Given the evolving nature of risks in the RE sector, this analysis provides a broad indication of how much these emerging risks could add to existing financing costs.

Addressing commissioning delays: Commissioning delays are a persistent challenge in RE projects, often caused by grid connectivity issues, delays in land acquisition, and lengthy approval processes for power purchase contracting. These delays can be mitigated through:

- Solar parks that operate on a plug-and-play model, pre-arranging land and connectivity infrastructure for developers
- State-level policies that streamline land allotment and acquisition procedures
- Pre-emptive grid connectivity allowing developers to apply for grid connectivity before the land is acquired or project is awarded to secure their position in the queue and minimise timeline disruptions
- Standardised, time bound PPA & PSA approvals by harmonising administrative procedures across states

Managing FDRE risks: Firm and Dispatchable Renewable Energy (FDRE) projects represent a new class of tenders aimed at increasing the dispatchability of RE. However, these projects come with unique risks due to the uncertainty in penalties for failing to meet dispatchability requirements, exposure to wholesale market price volatility for excess generation, and uncertainties around battery replacement costs.

Mechanisms like Contracts for Difference (CfDs) can help stabilise revenues by providing fixed strike prices for electricity, insulating developers from market fluctuations. Additionally, optimising the sizing of generation and storage systems is crucial to reduce oversizing and minimise the exposure of excess energy to volatile market conditions.

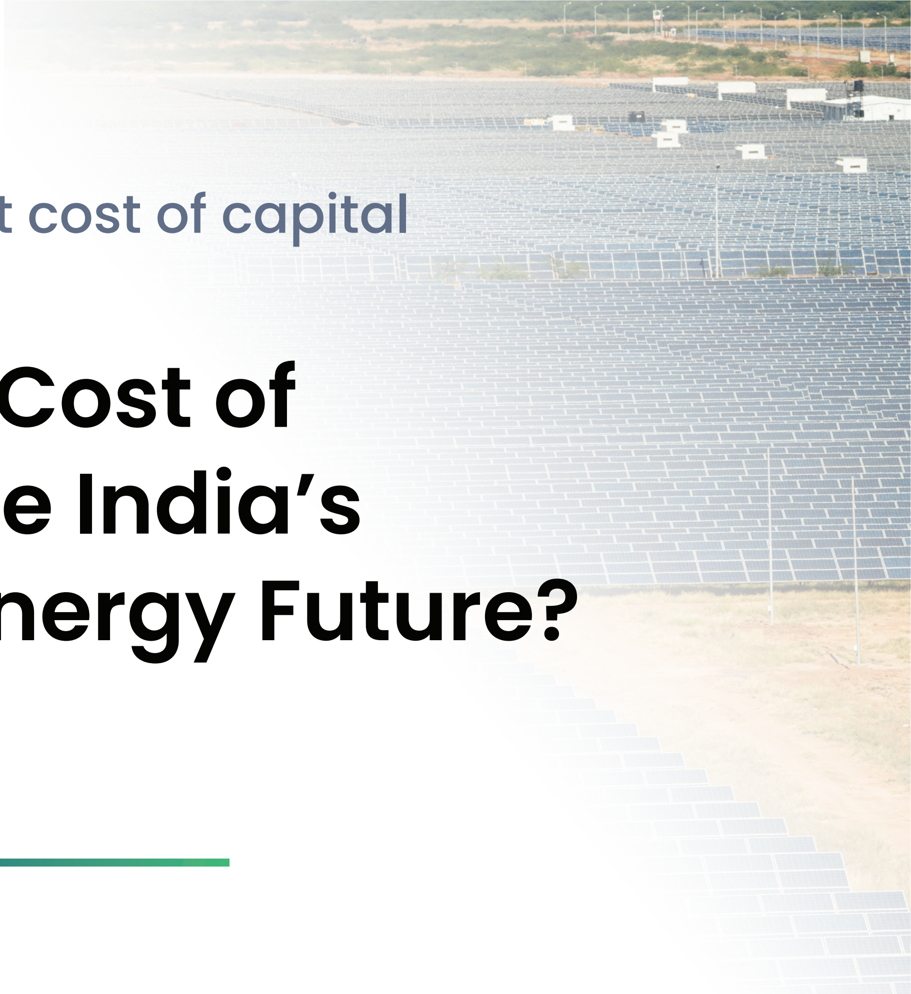
These FDRE projects, which represent a step toward achieving 24/7 RE, can benefit from concessional finance provided by international development banks and other sources of low-cost capital. Securing international financial support for such innovative initiatives will be crucial in scaling them fast. While domestic financial institutions in India like scheduled banks and specialized renewable development financiers are well accustomed to the risks associated with conventional solar or wind projects, these new-age projects will require significant low-cost finance in the initial stages until early projects establish a track record.

Addressing issues with domestic manufacturing: With energy independence becoming a critical global discussion, India has implemented various tariff and non-tariff barriers to bolster its solar manufacturing sector. Notable measures include the basic customs duty (BCD) and the Approved List of Models and Manufacturers (ALMM), both of which have seen multiple revisions. While these policies are designed to promote domestic PV manufacturing, they have also introduced considerable uncertainty around the availability and cost of PV modules. To address these challenges, a stable and predictable policy framework is essential, along with sunset clauses to ensure that the sector remains cost competitive.

Technology risks, such as failure or underperformance of critical components like panels, inverters, and batteries, pose significant challenges for RE projects. These risks can be mitigated by using components with proven reliability and securing warranties. Furthermore, finer technological issues can be addressed through data-driven operations and predictive maintenance strategies, thus ensuring improved reliability.

This analysis highlights how various risks impact on CoC and identifies potential mitigation measures. These insights can guide project developers, financiers, and the government to prioritise strategies for risk mitigation, whether through policy frameworks, innovative contracting methods, or risk hedging mechanisms. Effectively addressing these risks not only enhances the viability of individual projects but also drives the sustained growth of RE projects—one step at a time.

The analysis presented in this report is inherently tied to the contemporary context, acknowledging that the nature of risks in the RE sector evolves over time as the industry matures and operational conditions change. For example, around 2017, curtailment and counterparty risks were prominent due to inadequate grid infrastructure and weak payment rules for DISCOMs, respectively. Over the years, these risks have significantly decreased, while other concerns, such as power market volatility and DSM penalties, have taken centre stage. Given the dynamic nature of these risks, any study or framework aimed at understanding the determinants of the cost of capital must be regularly updated. As new challenges emerge or existing risks diminish, the analysis must be recalibrated to remain relevant and provide actionable insights for the current landscape.



How can the Cost of Capital Shape India's Renewable Energy Future?

The cost of capital will play a key role in shaping India's renewable energy future. Keeping the cost of capital low accelerates renewable energy deployment while ensuring affordable electricity for consumers.

A 400 bps increase in cost of capital can put off India's RE targets of 500 GW by 2030 by 100 GW.

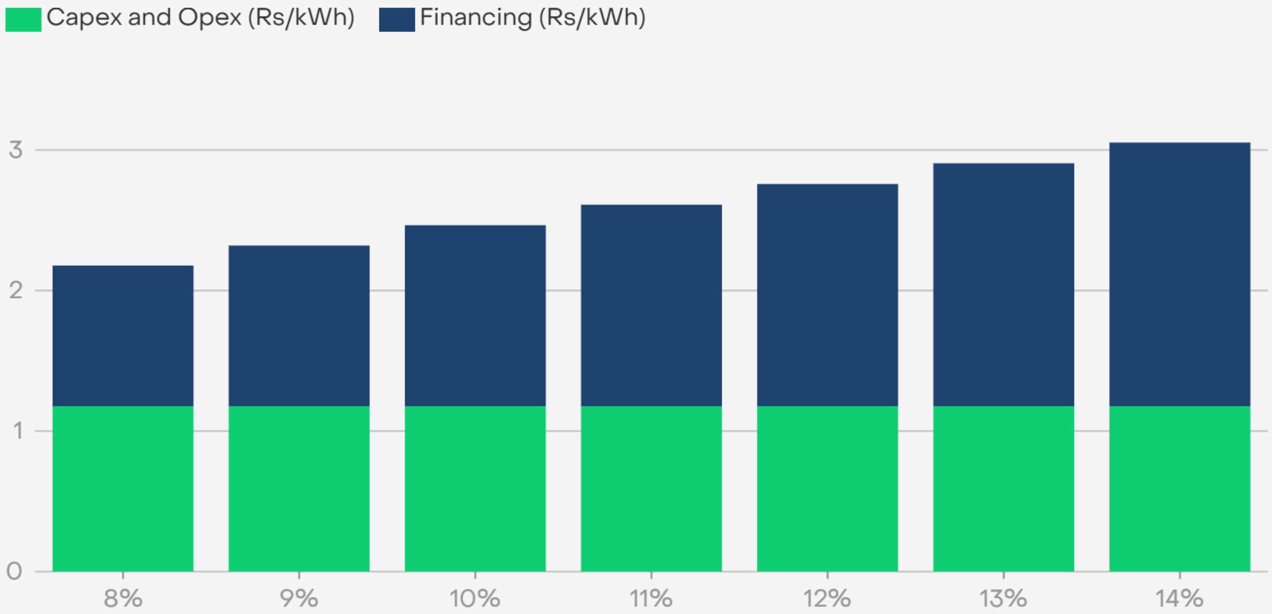
Even a moderate 200 bps increase in cost of capital (from 10% to 12%) could add ₹27,000 crore to annual electricity generation costs, while a 200 bps reduction (to 8%) could save approximately ₹32,000 crore.

Cost of capital significantly impacts the cost of RE generation

The CoC significantly affects the Levelized Cost of Electricity (LCOE) for RE projects due to their capital-intensive nature. Unlike conventional energy projects, which incur substantial operational/fuel expenses over time, RE projects require most of their investment upfront before commissioning. As a result, Cost of Capital (CoC) is a critical determinant of LCOE.

The cost of capital for solar projects has a significant impact on the cost of electricity generation

The levelized cost of electricity (LCOE) in Rs/kWh for different costs of capital



Source: Ember's estimates
Capex covers upfront costs like panels, inverters, and installation, while Opex includes expenses like maintenance, cleaning, etc.

In India, the generally acceptable CoC for RE projects is estimated to be around 10-11%. Our analysis indicates that for solar projects, a 10% CoC can result in financing costs contributing to 45-55% of the Levelized Cost of Electricity (LCOE).

Furthermore, a 100 bps increase in the CoC can lead to an approximate 5% rise in the LCOE, highlighting the significant impact of financing costs on the overall cost of RE generation. These findings underscore the critical role of maintaining a low cost of capital in ensuring the affordability and competitiveness of solar power.

High cost of capital impairs purchasing power of DISCOMs

As the share of RE grows, the cost of capital (CoC) plays an increasingly critical role in shaping the overall cost of electricity generation. A high CoC can either result in higher electricity costs for retail consumers or place significant financial strain on

Discoms, especially in states with weak utility finances. This dynamic can shift reliance back to coal-based power generation, further compounding the issue.

Our analysis for the year 2030 shows that an increase in CoC from 10% to 12% could increase power purchase costs for DISCOMs by 3%, or ₹0.12/kWh. Although this difference may seem modest, its impact is far from negligible, as the financial woes of DISCOMs primarily stem from the ₹0.55/kWh gap between the average cost of electricity purchased and the average revenue recovered. This gap resulted in ₹79,000 crore revenue shortfall for Discoms in FY23. This is more than half of the total budgetary allocation for the power sector in FY2024-25, including allocations for RE.

Keeping RE electricity costs low not only benefits consumers but also encourages DISCOMs to proactively seek more RE in their supply mix. The financial implications of a seemingly slight increase in CoC are substantial. A 200 bps increase in CoC (from 10% to 12%) could add ₹27,000 crore to annual electricity generation costs, while a 200 bps reduction (to 8%) could save approximately ₹32,000 crore. Beyond the energy sector, higher electricity costs can erode industrial competitiveness, especially for energy-intensive sectors reliant on affordable power. This threatens one of renewable energy's core promises of providing low-cost electricity while advancing sustainability goals.

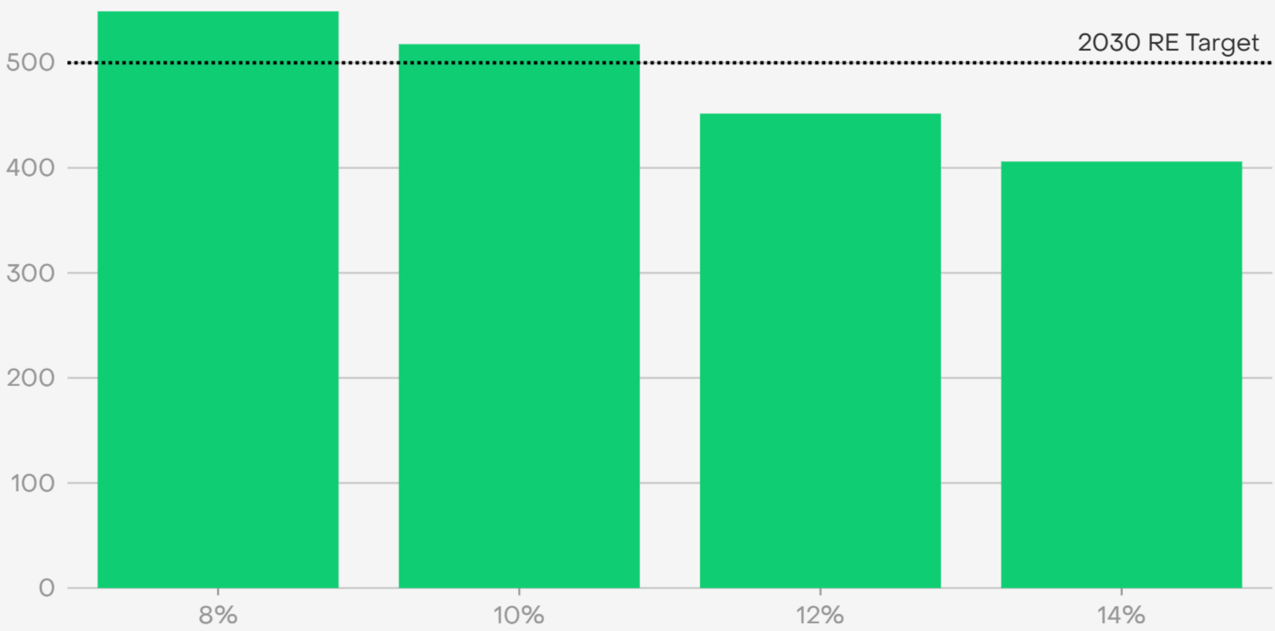
High cost of capital as a barrier to RE growth

As the CoC increases, the LCOE for RE increases substantially, making these projects less attractive. This reduced competitiveness compared to conventional fossil generation can lead to reluctance from DISCOMs or buyers to procure RE electricity, even when mandates are in place. Such hesitancy could dampen demand for RE capacity, this slowing down its uptake. This challenge is particularly pronounced in markets like India, where the affordability of energy services is vital.

If the CoC increases by 200 bps (e.g., from 10% to 12%), Ember's modelling estimates indicate that India's RE capacity by 2030 could be limited to 448 GW, falling well short of the 500 GW target. Conversely, a 200 bps decrease in the CoC (e.g., from 10% to 8%) could enable India to achieve 540 GW, far exceeding its target.

Higher cost of capital could make India miss its 2030 RE target of 500 GW

Optimal RE capacity (GW) in 2030 for different costs of capital



Source: Ember's estimates
Renewable Energy (RE) includes Bio Power, Hydro, Small-Hydro, Solar, and Wind

The cascading effect of a higher cost of capital (CoC) suggests that, over time—especially beyond the 2030 time frame examined in this report—India could add significantly less RE capacity if elevated CoC levels persist.

Such a shift could jeopardise India's clean energy transition and climate commitments, as a delayed scale-up of RE would make it harder to achieve long-term decarbonisation goals.

Methodology

Using the certainty equivalent method to calculate risk premium

The certainty equivalent method quantifies the risk premium by comparing projected cash flows under different risk scenarios, such as average (P50) and conservative (P90) estimates, to determine the additional compensation required for uncertainty in outcomes.

To illustrate this methodology, we calculate the risk premium for a potential shortfall in the capacity utilisation factor (CUF) due to weather-related variability, such as cloudy conditions or reduced sunshine. Historical data provides a benchmark for CUF variability; for example, a solar project in Rajasthan might experience CUF values ranging between 18% and 22%.

Steps to Calculate Risk Premium:

- Identify the scenarios:

  Average scenario (e.g., P50): In this scenario, the expected cash flow is based on the average CUF observed under expected/average regional conditions. For instance, if the average CUF in Rajasthan is 20%, this value is used to estimate the expected revenue of the solar project in the average scenario.

Conservative scenario (e.g., P90): In this scenario, the expected cash flow is adjusted downward to reflect more risky conditions, applying a "haircut" to account for uncertainty. This represents the certainty equivalent cash flow, or the guaranteed level of income an investor would expect in a worst-case scenario for CUF. For instance, if the CUF in Rajasthan under a P90 scenario is 18%, this value is used to estimate the expected revenue of the solar project under conservative assumptions, ensuring a more risk-averse financial projection.

The distribution of Capacity Utilisation Factor (CUF) can be modelled as a normal distribution, where the most likely values cluster around the mean (20%), while extreme cases (18% or 22% CUF) fall toward the distribution tails. Identifying the P90 estimate involves quantifying tail risks in financial modelling, helping to assess the likelihood of worst-case scenarios, where CUF drops to 18% or lower.

A holistic risk assessment must account for all potential risks, identified through literature reviews, stakeholder surveys, or expert consultations. Developing such risk scenarios relies on historical data to understand past trends and events. However, when data availability is limited, computational techniques such as Monte Carlo simulations can be employed to construct probabilistic risk scenarios, offering a structured approach to quantify uncertainties.

- Determine risk premium using certainty equivalent:

The difference in percentage terms between the two levels of cash flows—average (P50) and conservative (P90) scenarios—discounted to their present value, represents the risk premium for a specific phenomenon. In this case, it quantifies the additional compensation an investor might require if they perceive CUF shortfall as a significant risk, such as due to an anticipated increase in cloudy weather or fog.

Adding this risk premium to the base case (average scenario) results in the risk-adjusted discount rate, which reflects the higher cost of financing associated with greater uncertainty. This adjustment ensures that investors account for potential revenue volatility when making financing decisions.

Risk premia are typically expressed in basis points (bps)—a standard unit of measurement in financial markets used to indicate percentage changes in financial instruments. One basis point equals 1/100th of 1%, or 0.01%

While the methodology for assessing risk premiums appears objective and data-driven, it is inherently influenced by prevailing market conditions, which are often dynamic, as well as investor perceptions based on comparable projects. For instance, an investor with greater confidence in project performance might use P75 values for the return spectrum rather than P90. However, to maintain methodological consistency, this analysis employs P90 as the conservative scenario, which may lead to some risk premiums appearing higher than common industry estimates.

The certainty equivalent method can also be employed to compute the weighted average cost of capital (WACC) by accounting for all potential risks starting from a base rate or risk-free rate, a process known as the cost build-up method. This method can also be used to attribute various risks as a proportion of the WACC to understand the proportional magnitude of different types of risks and the uncertainty that they bring with them. A more detailed explanation of the certainty equivalent approach can be found here.

Calculating risk premium due to curtailment

Generators face revenue uncertainty due to curtailment, which occurs when grid constraints or reduced off-take limit energy dispatch. However, due to limited historical data, the distribution of possible curtailment is estimated using a Monte Carlo simulation, allowing for a structured assessment of curtailment risk.

In accordance with SECI tender specifications, generators are compensated for curtailments exceeding 175 hours of reduced off-take and 175 hours of grid unavailability. However, curtailment below this threshold remains an uncompensated risk, potentially impacting project revenues. To model this impact, we assume a probabilistic distribution that accounts for the hours of uncompensated curtailment, enabling a data-driven estimation of risk exposure.

Step-by-Step Process:

1. Simulation Parameters: The simulation is conducted with 1,000 runs to account for variability in curtailment. For each run, a normal distribution is assumed to model curtailment events for both grid unavailability and reduced off-take hours.

2. Modelling Grid Unavailability: Hours of grid unavailability are randomly selected from a normal distribution with a range of 0 to 175 hours. This distribution is centred at 0, with a standard deviation designed to approximate the range up to 175 hours, capturing the likelihood of different curtailment periods.

3. Modelling Reduced Off-Take: Hours of reduced off-take are similarly selected using a normal distribution between 0 and 175 hours. Additionally, the extent of generation reduction during these periods follows a normal distribution, with reductions ranging from 10% to 100% of maximum possible generation.

4. Curtailment Calculation: The simulation sums the curtailed generation for each run and calculates the curtailment percentage as the curtailed generation divided by the total possible generation in a year. This percentage reflects the extent of reduction in energy output due to curtailment.

5. Statistical Analysis: The results of the 1,000 Monte Carlo runs are used to derive the P90 and P50 values, representing the 90th and 50th percentiles of curtailment percentages, respectively.

Calculating the risk due to DSM penalties

Deviation Settlement Mechanism (DSM) penalties could pose a significant financial risk to solar generators, affecting revenue stability and investment confidence. This analysis quantifies the impact of DSM penalties by examining historical generation data and simulating penalties under existing and future DSM regulations.

Data collection & preprocessing

Historical 15-minute generation data from solar plants in northern and western regions was analysed, including actual generation values, scheduled generation, and deviation records over multiple years.

Penalty Calculation

Annual DSM penalties were computed as a percentage of total revenue under:

- Case 1 (Pre-2024 DSM Rules): Baseline penalties with P50 (expected) and P90 (conservative) levels, capturing uncertainty in penalties even without regulatory changes (Risk 1).

- Case 2 (Future DSM Rules): Stricter DSM frameworks (2024, 2026, and beyond) applied to the same deviation data to estimate penalties under progressively tighter DSM regulations (Risk 2).

The cumulative effect of potential revenue losses due to Risk 1 and Risk 2 is assessed.

Calculating the risk due to FDRE projects

Ember's FDRE modelling focuses on optimising FDRE capacity from a developer's perspective to meet tender specifications. The model ensures that the FDRE configuration meets demand profile while incorporating penalties into the optimisation process. This means that the final FDRE capacity is structured to optimise cost and revenue, and may optimise to pay some amount of penalty i.e. is designed to meet a lower demand fulfilment ratio.

Beyond meeting demand, the model accounts for oversizing, where excess generation beyond the contracted capacity is sold in the wholesale market. To estimate expected revenue from these surplus sales, the model uses historical Day-Ahead Market (DAM) electricity prices, mapping the distribution of revenue realisation over different years. By analysing the volume and timing of excess energy sales, the model helps in understanding how much developers can earn from the open market.

Additionally, the modelling assesses the risk of price cannibalization, particularly due to increased solar penetration in the Indian Energy Exchange (IEX) DAM. Through styled scenarios, the analysis explores how higher levels of solar generation could depress market prices, potentially reducing the revenue from excess energy sales.

Finally, FDRE capacity may be designed for a lower demand fulfilment ratio (DFR) and may be designed with an expected level of penalties, However, uncertainties related to solar and wind generation variability and performance issues in battery storage could lead to higher-than-expected penalties. To assess this risk, we simulate this for multiple hourly annual profiles for solar and wind generation and incorporate assumptions on battery cost deviations. This allows us to estimate the distribution of actual penalties under different scenarios. For instance, if the expected DFR was 75%, these uncertainties could lower it to 69% at the P90 level, resulting in higher penalty costs than initially projected.

A note on power contracting process in India

The renewable energy procurement process in India is a complex interplay involving multiple stakeholders, including the Solar Energy Corporation of India (SECI), state DISCOMs (distribution companies), renewable energy developers, and state electricity regulators. The step-by-step process is explained below:

1. SECI collects renewable energy demand from state DISCOMs, aligning these requirements with their Renewable Purchase Obligation (RPO) targets. Based on this aggregated demand, SECI issues tenders for renewable energy projects, inviting bids from developers. Developers submit their bids, and the winning bidders are selected based on competitive criteria, such as the lowest tariff offered.

2. Following the tendering process, SECI negotiates Power Sale Agreements (PSAs) with state DISCOMs to secure the sale of electricity generated by the projects. These agreements outline key terms, including pricing, quantities, and the duration of power purchase. PSAs must be approved by state electricity regulators to ensure compliance with state policies and safeguard consumer interests.

3. Once PSAs are approved, SECI signs Power Purchase Agreements (PPAs) with the winning renewable energy developers. These agreements formalise the procurement terms and offer financial security, enabling developers to secure financing and begin project execution. However, delays in PSA approvals can directly postpone PPA signing, disrupting project timelines and increasing risks for developers.

Acknowledgements

Lead authors

Neshwin Rodrigues, Duttatreya Das

Other contributors

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Cover image

India, Rajasthan State, Jaisalmer, Maharajas' cenotaphs

Credit: Hemis / Alamy Stock Photo