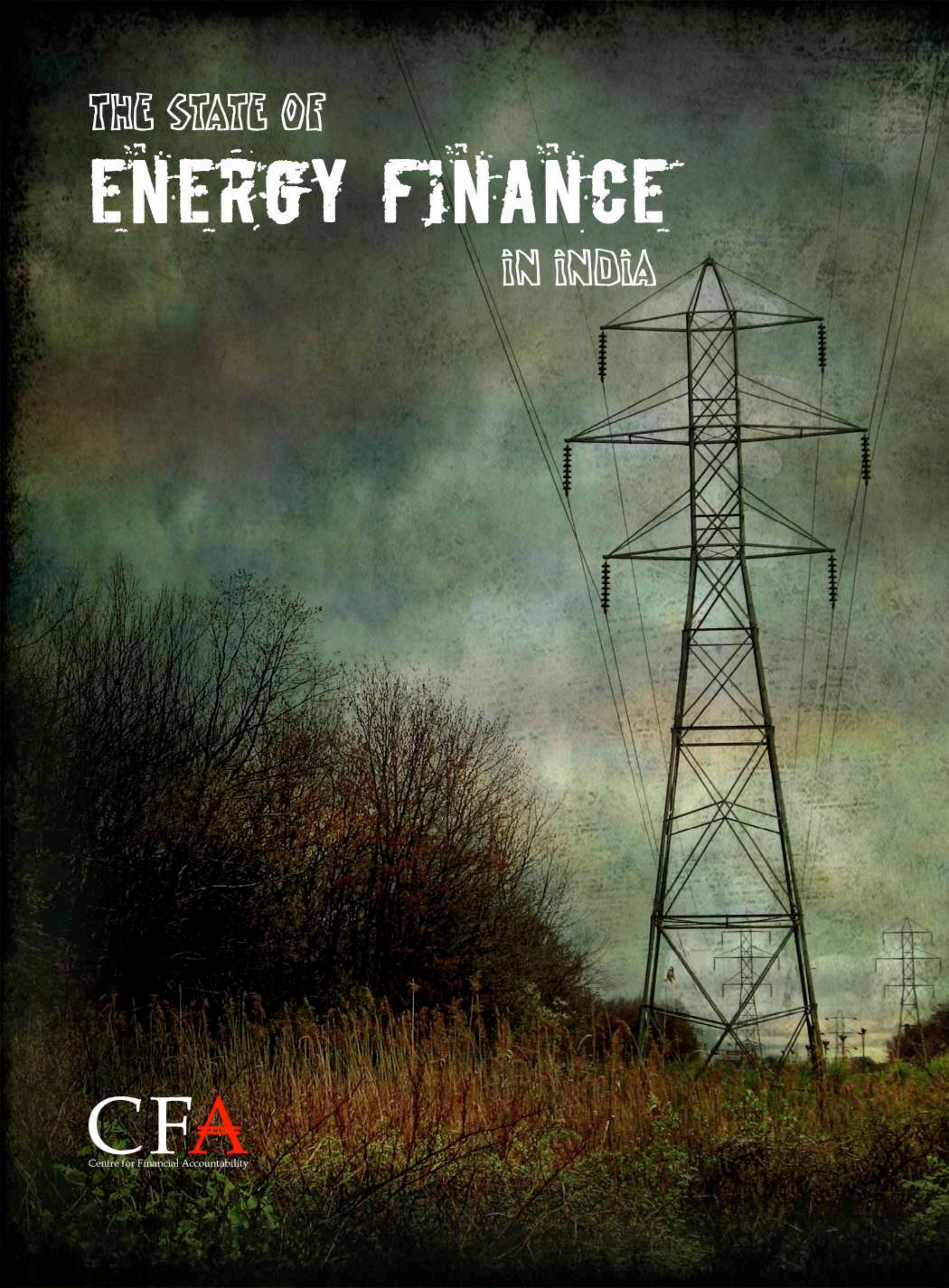
THE STATE OF ENERGY FINANCE IN INDIA



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The State of Energy Finance in India

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Introduction

Wind and solar electricity costs have fallen so much that building new renewable generation is now cheaper than operating 39% of the world's existing coal capacity, and this will increase to 60% of existing capacity in the next two years, according to the UN. Half of India's current coal capacity will be uncompetitive against renewables in 2022, said, Antonio Guterres, while speaking at the Darbari Seth Memorial Lecture on August 22, 2020. He further added that if the 1.5 degree limit is breached then India will endure more intense heatwaves, floods and droughts, increased water stress and reduced food production, all undermining progress towards the Sustainable Development Goals.

He ended by saying that both the pandemic and the climate crisis have raised fundamental questions about how to ensure the health and well-being of the world's people and about how nations must cooperate to advance the common good.

This booklet by Tanya Thomas is a critical study looking at India's energy systems and issues surrounding it today. Based on facts and current trends she offers not only the way ahead but also seeks answers to uncomfortable questions not being asked around the sudden renewables growth. There are legacy issues with the hydro and then there are environmental and economic costs with the fossils, she discusses it all.

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As the country went through a lockdown period in March, initial slowdown of economic activities resulted in the brief moments of cleaner air, less pollution and sudden improvement in climatic conditions. However, it has definitely not caused a dent in the unfolding climate crisis, as we witness the worsening air pollution in Delhi and other big cities. The uncertainty remains on finding a cure for the health pandemic as much for the climate crisis.

The reaction from the government's world over have been mostly on the predictable lines and in the name of the economic recovery the prescriptions are as expected, which means delaying significant steps for tackling climate crisis due to sudden economic slumps, even basic minimum technological changes have now been put on hold. The rush to restart the economy and push for manufacturing and consumption mean more emissions.

It was reported that during the pandemic, India's proportion of renewable energy rose from 17 per cent to 24 per cent while coal-fired power declined from 76 per cent to 66 per cent. Even then there is no coal phase out plan in sight. The deadline for the installation of flue-gas desulfurization (FGD) units in the power plants continue to be extended for one reason or the other, as has been pointed out by the author inside in chapter two. Not only this, the country has increased its focus on increased production of the domestic coal and taken steps for commercial mining.

As pointed out by the UN Chief and also argued in detail by the author of this paper, coal makes no social and economic sense given its high social and environmental coasts and continued competition from other cheaper renewable sources. The message is clear 'there is no money to be made in thermal'. But the party continues.

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UN chief lauded India for the lead it has taken in renewables and specially lauded its efforts at international platform by taking the leadership in International Solar Alliance. However, the path from fossils to renewable is not an easy one and there are lessons to be learnt from the past mistakes, some of these have been argued in detail by the author in each of the chapters.

Electricity production from dams have now been categorized as renewable, even though it remains contested and there are legacy issues with the big dams in India which remains unaddressed till date. Dams have failed, not only to meet its desired irrigation potential or electricity generation targets but have been mired in controversies with huge cost and time overruns, long lock in investment periods and humongous social and environmental problems. Most of the dams have faced time and cost overruns and as mentioned in the first chapter it is not advisable to plan or execute any more new hydro and if necessary abandon or scrap projects where work has not significantly been achieved, something which will be in economic interest too. Unfortunately, new contracts for building dams in the ecologically fragile region of the Himalayas have already been planned and are being pushed forward by the governments. These remain a challenge for environment.

And lastly, the big names in the renewables today are Adani, NTPC, and few other leading players of the fossil industry, who have read the writing on the wall and taken early lead in this. It may be as part of their diversification plan but carries all the marks of their historical legacy. The renewable development in India is following exactly the same patters which it did while developing coal and big hydro. There are problems of over acquisition of land than required, financial opaqueness, cost overruns and complete violation of the environmental and regulatory regimes. There is a rush to meet the targets but then there are no plans in place in dealing with the after project waste, or water requirements and the environmental impact of the same.

The chapter on the renewables raise these issues including the problems with the current policy regime, grid stability and then of course the boom in this sector and how far that can be sustained given the volatility in the overall electricity market in India today.

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All this power generation is being undertaken keeping in mind the growth projects but as we recover from the pandemic and unfolding economic crisis it’s not going to be easy to continue this level of consumption. In such a scenario what’s going to be the future ? If that’s a question for everyone to answer then there is the question of legacy.

The energy generation projects in India, coal and big hydro have left nearly 500 million displaced from their land and livelihood, who are yet to achieve any credible resettlement and rehabilitation despite India having a new law recognising their right to R&R and compensation. In addition, India has already abandoned nearly 450 GW plus of planned thermal plants for various reasons since 2010, the land acquired for many of them remains with the authorities while farmers continue to fight to get them back. In addition, the old mines which are being closed leave a gaping toxic hole without any credible mine rehabilitation plans in sight. An estimated 70 GW thermal power plants along with their ash ponds are closed or will be retired by 2027 and abandoned without any credible plan for their rehabilitation too.

Mere shift from the coal based electricity production to the solar or wind is not going to mean a just transition for the Indian economy, because there are legacy issues but also the issues of jobs which needs to be looked at. Coal sector is a big employer and there are not going to be so many jobs in the renewable sector which means emphasis and planning for the rejig of the economy which can generate green and sustainable jobs. Is anyone thinking about it ?

The current government functions as, a slogan a day, and the one in circulation right now is #AtmaNirbharBharat but India can be self-reliant only if its villages and cities will be self-reliant and that would mean a shift from the energy and capital intensive economic systems, which raises the question on the current development paradigm. The current obsession with the growth and infrastructure development model is neither a path to ecological India or India ready to fight the climate crisis.

The booklet provides an opportunity to look at these issues and provides us a window into the current developments in the electricity sector.

Madhuresh Kumar
National Alliance of People's Movements

Damming Our Future: The Case Against Building New Hydroelectric Power

Does India need to build more hydroelectric power than it already has? While the growth in thermal-based power and renewable energy is commensurate with the long-term growth path of national power demand, the future of hydroelectric appears muddled in comparison. In India, the story of hydroelectric power is one of multiple contradictory realities, with a long-standing dissonance between government policy and ground reality.

India has about 45.6 gigawatts (GW) of installed large hydroelectric power capacity today, accounting for 12% of the country's 371 GW capacity of power generation. The central government, through its in-house policy think tank Niti Aayog, wants this number to reach between 65 and 70 GW by 2030. Towards this end, the government declared all hydropower projects as "renewable energy" in March 2019, clubbing it in the same category as solar and wind power, and creating hydro purchase obligations to boost their long-term financial viability.

Investments pour in

According to the nationally determined contributions under the Paris Agreement, India is targeting a share of non-fossil-based capacity in the electricity mix of more than 40% by 2030, effectively reducing emissions by a third from 2005 levels. In the government's plans, classifying large hydropower as renewable energy and promoting new projects is key to maintaining flexibility and stability to the national grid, especially as the contribution from infirm power sources like wind and solar rise. The Niti Aayog sees hydropower as sustainable and has estimated that investments of up to $31 billion will go into the sector over the next decade.

According to the Central Electricity Authority (CEA), as of March 2020, India had 11,975 MW of hydroelectric power stations under construction which, on an average, are running behind schedule by 8 years. Their project costs have nearly doubled through this delay from their initial estimates. However, the CEA insists that India has the potential to build still more. The CEA has identified 1,48,701 MW of hydro capacity potential overall, which at a 60% load factor would amount to 84,044 MW of real hydro generation. Essentially, the CEA believes that about 65% of hydopower capacity in India is yet to be harnessed, primarily in the Brahmaputra, Indus and Ganga river basins.

On the ground, however, the reality is very different. Setting up one megawatt of hydropower costs about Rs 8-10 crore at initial estimates - hydro projects are notorious for massive cost and time overruns and these costs undoubtedly balloon by the time the project is commissioned - while the comparable cost for one megawatt of wind or solar energy takes Rs 3-4 crore, depending on location and equipment prices, and utility scale projects can be set up within 18-24 months. Naturally, as equipment prices for renewable power fell over the last decade, the flow of money was diverted there as well.

Over the last decade, the private sector has almost entirely bowed out of hydroelectric power. Of the total installed capacity in India, only 3.2 GW is with private companies. The largest capacity belongs to Sajjan Jindal's JSW Energy which has two hydropower projects - Baspa II (300 MW) and Karcham Wangtoo (1080 MW) - in Himachal Pradesh. JSW agreed to set up a third plant in Himachal - 240 MW at Kutehr - in 2007. Construction work here is yet to begin while the company waits to sign long-term power purchase agreements with buying states. Tata Power, which began life in in 1910 as the Tata Hydroelectric Power Supply Company, now has only 447 MW of installed hydroelectric power out of of its total generation portfolio of 12,264 MW. Tata Power's solar and wind energy portfolio today. By comparison, stands at 2637 MW. Besides these, renewable energy company Greenko, which operates 22 run-of-rive hydroelectric projects of 1689 MW, is the only other large player of note in the sector. Outside of the large well-capitalised private companies, privately owned hydro power projects are now up for grabs. State-run NHPC recently bailed out two bankrupt hydroelectric projects - Jal Power Corporation's Rangit project (120

MW in Sikkim) for Rs 165 crore and the under-construction 500 MW Teesta VI in Sikkim for Rs 897.5 crore in exchange for Lanco Infratech's 30% equity in the project.

So it falls to the public sector again, be it state government companies or public sector units like the NHPC Ltd (formerly the National Hydroelectric Power Corporation), to keep pouring money into new projects. As a result, progress is slow and new capacities are coming up at the rate of 1% a year. Data from the Ministry of Power bears out the fact that the rate of capacity addition in hydropower is moving at a snail's pace. Over the last three financial years of 2017-18, 2018-19 and 2019-20, central agencies added 800 MW of new projects, against a target capacity addition of 2110 MW. State-led agencies added 230 MW, against an expectation of 641 MW. The private sector added 205 MW against a target of 584 MW, drawing a blank the last two years.

The same old mistakes

A case in point is the 3097 MW Etalin hydropower project, proposed to be built in Arunachal Pradesh in the Dibang valley, home to a diverse ecology and indigenous communities of northeastern India. The proposed dam and hydro generation plant is a joint venture between Jindal Power Ltd and the public sector Hydro Power Development Corporation of Arunachal Pradesh Ltd.

Manthan Adhyayan Kendra, a policy research centre that analyses water and policy issues, in a detailed report to the Ministry of Power argued against greenlighting the project, quoting the CEA's own long-term energy prescription where it has prescribed no new hydro power till 2029 beyond those already under construction. The Etalin project has already been delayed by six years and is still awaiting forest clearances for 1166 hectares of land that it needs. As per the project report, pre-construction activities were supposed to be completed by October 2015 and the project itself should have been commissioned by September 2022, at a cost of Rs 25,296.95 crore and a power tariff of Rs 5 per kilowatt-hour (kWh).

With the project already running behind schedule, Manthan redid the forecasts of project costs and final power tariff under one scenario 1, where the construction begins in October 2020 and completes in 2027, and a second scenario, where the project deadline is extended to 2031 because of a further delay in construction. Manthan estimated the the cost of the project would shoot upwards to Rs 33,320 crore in scenario 1 and Rs 44,240 crore in scenario 2, with the tariffs rising proportionately to Rs 6.96 per kWh and Rs 9.25 per kWh.

"In the past, several capacity addition decisions including those pertaining to large hydropower projects have been undertaken based on unrealistic cost assumptions that made them seem lucrative," Manthan's report to the Ministry of Power said. "However, when the real costs became apparent, the discoms (distribution companies) and the state governments concerned have been forced to rethink such decisions." It quoted the Madhya Pradesh government terminating a power purchase agreement with the high-cost Maheshwar hydro project in April this year when the government was informed that the new indicative tariff, which includes the cost overruns, had risen to Rs 18 per kWh, from the initially agreed cap of Rs 5.32 per kWh over the project's lifespan. Shripad Dharmadhikary of Manthan said: "The cost of new new hydro power is very high and it is clear that discoms will not buy such expensive power. We suspect increasingly these will be white elephants, especially in a future where solar-with-storage can be far cheaper in the range of Rs 3-4 per kWh compared to hydro. But if we go ahead with these projects, the ecological damage will already be done while there will not be any takers for the power."

Regardless, the public sector will keep investing. NHPC, the government-owned hydroelectric behemoth, is in the midst of a seven-year Rs 1 trillion capital expenditure programme to expand its generation capacity. NHPC operates 15% of the installed hydroelectric market in India (6971 MW of 45.69 MW) through 24 projects across the country and has another 4924 MW of projects under construction and a further 7200 MW of projects (costing Rs 68,700 crore according to their detailed project report estimates) awaiting official clearance. NHPC declined to respond to emailed questions or phone interviews with its management for this report, so it's hard to guess at the company's long-term rationale for creating large greenfield hydel projects. But the intent to march ahead is clear. In its most recent interaction with its public investors (retrieved from annual reports, investor call transcripts and quarterly presentations), the company said that is discussing new projects such as Dugar in Himachal Pradesh (449 MW), that it is in talks with the Uttarakhand state government to make four previously unviable projects (762MW in Chungar Chal, Karmoli Lumti Tulli, Dhauliganga Intermediate and Goriganga III-A) viable using exemptions from the state government; that the Bursar project (800MW) in Jammu and Kashmir is in the pipeline and that it is exploring the potential for three new projects in Ladakh of 155 MW.

Despite the scale of its ambitions, NHPC is no stranger to stranded and long-delayed projects. The company was given the construction contract for the 2000 MW Lower Subansiri project in 2003. At an initial project cost estimate of Rs 6285 crore, the hydroelectric project on the Subansiri river, a tributary of the Brahmaputra straddling Arunachal Pradesh and Assam, was to be the largest hydroelectric project in India by the time of its completion in 2010. A decade later, it is still under construction, but now comes with a cost and works bill of Rs 20,369 crore. The project has met with fierce opposition from local populations on the ecological impact of damming the Brahmaputra, following which NHPC pushed the completion date to September 2023.

If the Lower Subansiri project does indeed get commissioned by 2023, it will be 20 years from when the company started work on it. The reason NHPC can shoulder the costs of these delays is that government intervention allows it raise debt at very low interest rates (about 70% of any project's cost is external debt; very little of the company's own equity is tied into these projects.) This, coupled with the fact that the financial returns on hydro power projects only need to cover fixed costs (they have no variable/running costs, such as the cost of natural gas or coal in thermal power), allows project owners considerable leeway in efficiently completing projects on time and within cost estimates. Meanwhile, for states buying power from Lower Subansiri can see their tariff expectations multiply at least more than three times from Rs 1.93 per kWh in the 2002-03 estimates to Rs 6.36 now (2017 estimates).

Despite this high tariff being uncompetitive today given far cheaper sources of electricity for buyers, project owners believe that once a hydro project is on stream, all surplus production above the design energy will help recover their costs sooner. For instance, the Lower Subansiri has a design energy of 7421 million units of power generated annually. While the long-term power purchase agreement is fixed at a certain tariff, the reason why discoms may still agree to sign them is because they expect actual production to be higher than the design energy. States which have signed these agreements with a power project have the right of first refusal to excess power generation; this power can be sold at rates of under Re 1 a unit. So for a discom, if it can access this surplus generation, its average hydro power procurement cost falls below the tariff rates.

But this is a big if. The submission by Manthan Adhyayan Kendra quoted research that showed that 89% of currently operational hydropower projects in India produced below their design energies and about half produce below 50% of their design energies.

The peaking power argument

Another reason hydropower continues to find favour with policymakers is because reservoir-based hydropower has the advantage of offering stable and reliable power during hours of peak demand at cheaper marginal rates. These projects can ramp up or down their production and meet precise load requirements in a matter of minutes when compared to other energy sources. This ability of a generator to raise and maintain the generation at the maximum output level for a limited period so as to cater to the peak demand requirements in a power system is called peaking, and is a typical grid support service rendered by the hydro and natural gas generators. For instance, during the 10 minutes of Prime Minister Modi’s lights out campaign on April 5 this year, generation from hydropower sources kept the grid stable: hydro generation was maximised by 8:45 pm that evening to 25,559 MW and quickly reduced to 8,016 MW at 9:10 p.m, while thermal, natural gas and wind power supported the base power load.

However, reservoir-based hydrostations, best suited for peaking power, are generally multi-purpose projects which cater to regional irrigation and drinking water requirements and flood control requirements besides power generation. This limits the quantum of energy that can be generated during that day. However, even with these restrictions, a study published by the Forum of Load Despatchers India in 2017 for the Ministry of Power found a potential of 2000 MW of additional peaking support from existing hydro generation in India.

This year, generation from hydropower and renewables increased year-on-year. In June 2020. for instance, the latest data that is available from the country's grid manager POSOCO (Power System Operation Corporation Ltd, the national load despatch centre), hydro generation was recorded to be 18,401 million units, rising between 22 and 24% from both May 2020 (15,005 million units) and June 2019 (14,787 million units). With solar and wind power's contribution to the overall energy mix bound to multiply in coming years, it makes sense for hydropower projects to be shifted from base load operations towards meeting peaking requirements to better integrate newer sources of power into the grid.

Himanshu Thakkar, coordinator at the South Asia Network on Dams, Rivers and People (Sandrp), believes that hydropower projects are no longer even economically viable considering much cheaper sources of power being available. "The claimed USP of peaking power provision by hydro projects is not really convincing since no agency is even monitoring or optimising to ensure that existing hydro projects provide maximum power during peaking hours. There is a lot of evidence including as late as in June 2020 that shows that existing hydro, even when they can operate as peaking stations, prefer to operate in baseload mode. Besides this, there is of course the exorbitant and unverified high costs of investment required per megawatt of new installed hydro capacity. So there is absolutely no case for new hydro. On the contrary, we need to start considering cases for decommissioning."

Room for optimisation

Those opposed to building new hydro projects, which leave behind both a large economic and ecological cost, argue that existing projects can be better optimised for power generation. NHPC, for its part, is tentatively exploring using its reservoir-based projects for floating solar power installations. The company has signed agreements with Kerala, Odisha and Telangana to for setting up floating solar projects of up to 1050 MW. Past studies by Sandrp have recommended exploring adding a hydropower generation component to India's existing large dams, of which less than 3% today generate power, instead of damming more rivers. Existing projects can be optimised further by creating pumped storage plants, which store energy by moving water to two reservoirs at different elevations. In fact, the 2017 study by the Forum of Load Despatchers India recommended a broader implementation of pumped storage across India using differential tariffs for use during peak and off-peak hours. The CEA has identified potential of over 96 GW at 63 sites for pumped storage; today, we have only five plants with capacity of 2200 MW operating in pumped storage mode.

Finally, there are the truly green small hydropower projects (below 25 MW) that seem to have disappeared from policy consciousness altogether. These stations run on small turbines and don't require damming a river. Despite the environmental benefits of setting up more small hydro, India today has only 4.67 GW of installed capacity with little or no new capacity being added in recent years. With falling tariffs on solar and wind power, more willingness among the private sector to participate and much lower capital and gestation costs compared to small hydro, the latter is faced with significant policy indifference.

The final argument against large hydro power comes from lithium battery storage. While still expensive, industry experts agree that even with the nascent technology that exists today, a solar photovoltaic system with 25% lithium battery storage would cost Rs

5-6 per kWh. This is far cheaper than the tariff expectations on an under-construction hydropower project like Lower Subansiri or a proposed project like Etalin. As storage technologies improve, their costs are bound to fall further even as we lock ourselves into higher long-term procurement costs by building new hydropower projects.

Big Coal Is Here To Stay

In July 2019, ICP Keshari, additional chief secretary for energy in the Madhya Pradesh government at the time, was drawing up plans to set up a 4000 megawatt (MW) greenfield coal-fired power project in the state.

According to the minutes of the meeting by the Madhya Pradesh Power Coordination Committee, which greenlit the project, the state wanted to procure 2640MW through competitive bidding (2 plants of 1320MW each) to private operators while another 1320MW of capacity was be added by the state's own MP Power Generating Co Ltd plants at two locations, 660MW at Satpura and Amarkantak each. The 4000MW of new capacity was supposed to come on stream in FY2024-25.

At the time of the committee's meeting, the project drew attention because it was counter-intuitive. Nearly all power generators in the country, whether state-owned generation companies (gencos), independent power producers (IPPs) or even the public sector behemoth National Thermal Power Corporation (NTPC), had by then checked out of investing any more in coal. The power sector was instead pouring money into utility scale solar projects and pushing for policy on repowering ageing wind farms.

Meanwhile, coal-fired power was gradually falling out of favour. The previous year, the 2018 Parliamentary Standing Committee on Energy had found that 34 large coal plants with installed or under-construction capacity of 40.1 gigawatt (GW) were stranded. The promoters on these projects owed their lenders Rs 1.74 lakh crore, much of it which their banks would have to write off as bad loans. Of this 40GW that is stranded, 15GW is yet to be commissioned. Having burnt a massive hole in their balance sheets, banks were no longer willing to invest buckets of capital into new coal-fired projects that take 5-6 years on average to start producing power.

Despite the overwhelming sentiment against new coal plants, Keshari found merit in his project. "For the past four years, Madhya

Pradesh has supplied 24x7 power to non-agricultural users and 10 hours a day to agricultural users," Keshari told this writer at the time. “We cannot cut down on supply. On the other hand, we expect the power demand in the state to grow at a rate double of the national average. In fact, the Central Electricity Authority has predicted a shortfall of 5GW by 2026-27. Madhya Pradesh needs to add 600-700MW every year, through thermal and renewable power. We want to be future ready."

However, a year from then, the state has been able to sign only a third of the capacity it wanted to build. In May 2020, Adani Power, part of the business conglomerate promoted by billionaire Gautam Adani, won approval from the MP Electricity Regulatory Commission to set up a 1320MW coal power plant in Chhindwara, under the former’s subsidiary Pench Thermal Energy. The project is expected to start construction in 2022 and slated for completion in 2026, at a cost of about Rs 7200 crore.

“In six months or a year, maybe we’ll plan for the second part of this project,” Keshari said in a more recent conversation. The bureaucrat is not actively overseeing the project any more and his previous confidence in the project has waned.“We’re planning to stagger the capacity addition now. Life after covid-19 won’t be the same and we don’t how consumption will change in the long-run.”

India’s experience through the covid-19 pandemic and stringent national lockdown that followed has converted the last of the fossil fuel apologists. India is an electricity surplus country with an installed capacity of 368GW against a peak demand of 186GW. India added 80GW of thermal (coal, natural gas) power plants in the last five years, the highest in any five-year period. IPPs in the private sector own 47% of overall capacity— 48% of thermal and 43% of renewable— while the central government owns 25% and state governments the rest.

However, plant utilisation in thermal projects has crashed, even as capacity increased. Thermal plants, on average, run at plant load factors - a measure of how much power a plant generates against its available capacity - of 50-60%. This means that about half the capacity of the coal-fired and natural-gas dependent power plants in India lie idle. The Central Electricity Authority's National Electricity Plan says that India, even after accounting for rapid growth in India's electricity demand, will not need to add any additional thermal supply till 2023.

It may as well turn out to be that the country will not need to add to its thermal power capacity ever.

The reasons for this are twofold - one, the long gestation period needed to build a thermal power plant makes it financially unattractive and two, technology and its progress over the next decade is bound to give us more efficient and affordable ways of not just generating power through renewables but storing excess electricity as well.

There's no money to be made in thermal

For the past four years, India's thermal power landscape has been strewn with unfinished projects, bankrupt projects and unviable projects. According to a Bank of America Merrill Lynch estimate, the total stressed debt in the power sector was $53 billion (or Rs 3.6 trillion). The insolvency and bankruptcy code introduced in 2016 allowed new bidders who found value in bankrupt projects to take them on for dirt cheap. Banks were able to sell abandoned steel plants, textile firms and cement companies. In contrast, they've been far less successful getting power projects off their hands. In 2017, the Reserve Bank of India formally recognised 34 stranded power plants as in need of rescue; three years hence, only five of these 34 have been resolved.

The 2018 parliamentary panel identified the reasons the following reasons for stress in thermal sector: a lack of adequate fuel supply - either due to cancellations in assigned coal/natural gas linkages or projects set up without any coal/gas linkages; projects unable to sign feasible long-term power purchase agreements (PPAs) with state distribution companies; the inability of promoters to infuse additional equity and working capital when needed; delays in project implementation and cost overruns; tariff-related disputes; or lack of adequate liquidity from banks and financial institutions. The biggest blow was when the Supreme Court cancelled 214 coal blocks, which had been allocated by the Inter-Ministerial Group from 1993 onwards, in 2014. This order, and the disputes that followed, single-handedly placed 24GW of captive coal-based thermal capacity under stress.

While all these factors have contributed to the decline of coal, the unvarnished truth is that private sector doesn't find coal-fired power viable the way it used to be.

Consider this hypothetical situation, explained in a February 2018 report by credit ratings agency India Ratings. The agency analysed the financial viability of a notional coal-based power plant, with a capital cost of Rs 6 crore/megawatt and a 70:30 debt-equity funding, typical of plants being set up in the past decade. The plant had signed a PPA of Rs 3.35/kilowatt hour (or, a unit of power) with a state discom - again, a typical scenario for plants set up in the past decade. India Ratings said that for the plant to be profitable, the promoter would have to bring down the cost to two-thirds of the planned Rs 6 crore/megawatt. If it did, it could then possibly service its debt and provide a 10% return on equity, while running at the industry average of 60% plant load factor. Readjusting these financial metrics to bring down fixed costs of operations means both promoters and banks - the bringers of equity and debt - would have to take giant haircuts on their ongoing investments. Neither has been willing to do so.

Besides this, coal-fired power plants are designed to be highly dependent on water, and about 90% of India's installed capacity is dependent on freshwater for cooling. According to the World Resources Institute, power generation alone uses up 22 billion cubic metres of fresh water per year (on 2016 figures), more than half of India's domestic water requirements. Further, about 40% of India's current thermal capacity is located in water-stressed areas, with water shortages leading to losses in electricity generation and significant revenue losses for power producers.

Input costs determine the viability of a power plant and how competitive its tariff is, especially competing against renewable energy, influencing the decision on whether a new plant should be built or not. In a December 2019 report, the Institute for Energy Economics and Financial Analysis wrote the local availability of coal is now a far more significant factor in determining where a new plant comes up than before. States such as Jharkhand, Odisha, Chhattisgarh, West Bengal and Madhya Pradesh - which produce about 80% of the country's thermal coal - are more amenable to setting up new projects than states with no coal blocks within their boundaries. States such as Karnataka and Gujarat with high electricity demand growth and little in-state black coal mining capacity, have traditionally depended on imported coal or coal hauled across the breadth of the country by the Indian railways to keep their power plants running. Since 2018, both coal prices and the railway freights have gone up, increasing the marginal cost of production of power. In fact, an analysis by Brookings India in November 2018 found that the Indian Railways were overcharging coal freights by 31% to offset losses from passenger coaches. The additional freight charge alone increased the cost of power, on average, by about Rs 0.10/unit.

There are ways to make coal power cleaner and more efficient, but it requires investment and a policy push that the country isn't seeing. Roughly 4 out of every 5 coal-fired plants in India use obsolete sub-critical technology with higher than average CO_2 emissions. Indian-produced coal is about 30-50% ash, which means the more coal we burn the more ash, noxious gases (sulphur dioxide, nitrogen dioxide), particulate matter, ash and carbon emissions are produced. In 2015, the government introduced new emission standards for coal-fired power plants to be met by 2017; when plants failed to comply, the deadline was extended to 2022. A study by The International Institute for Sustainable Development and the Council on Energy, Environment and Water found that only two out of 441 plants studied had commissioned the required flue gas desulphurisation technology which lowers sulphur dioxide emissions by over 90%. Operational plants may have to invest at least $10 billion and increase costs by Rs 0.32-0.72 per kilowatt hour to meet the pollution standards, the study estimated. Meanwhile, coal washeries - units that reduce the ash content in coal through segregation, blending and washing techniques - have fallen out of favour yet again. Although the government's policy think tank NITI Aayog stated as recently as this January that all new coal plants need to use super critical technology and washed coal, the government has now backtracked on its own demands for cleaner coal being used.

At about the same time as investments into new coal or even cleaner coal fell, states such as Karnataka, Andhra Pradesh and Gujarat led the charge in setting up renewable energy plants. They are now home to some of the largest utility scale solar plants in the country and have found the means to provide power to their residents circumventing the increasing cost of coal.

If there have been some survivors in coal, investors in natural gas plants have been decimated. More than half of India's capacity to generate power from natural gas (about 25GW) is simply lying idle for want of gas. These plants cost about Rs 4-5 crore per MW to set up. With the plants not bringing in any revenue, about Rs 60,000 crore of bank loans to this sector have turned sour.

India made its policy leap into natural gas-fed power in the early part of this century by counting on the reserves from the Krishna Godavari (KG) basin in Andhra Pradesh, the largest natural gas basin in the country. KG D6 was supposed to provide 80 million metric standard cubic meter per day (mmscmd) by the end of 2009, increasing every subsequent year. But over the past decade, the reverse happened. From producing 55.35 mmscmd in 2010-11, production fell to a tenth - 5.5 mmscmd - in 2017-18. Today, the basin produces next to nothing.

India has other gas reserves in the Hazira basin (Gujarat), Mumbai offshore and in Assam and Tripura. In the 2018-19 fiscal year, India produced, 90.05 mmscmd of domestic gas. With city gas distribution and gas supplies to urea manufacturing plants taking precedence over power generation in government policy, gas power plants received only about 25 mmscmd each year, which meets the needs of only about 30% of installed capacity. For power plants, importing natural gas is prohibitively expensive while domestic producers would often forego all production than dig for natural gas at the artificially deflated government-controlled pricing formula.

Meanwhile, the renewables sector has seen the cost of modules, and therefore the cost of the power generated, crash. New solar power plants are able to sign tariff agreements at Rs 2.70-3.30/kilowatt hour, take 18 months to set up and are heavily subsidised by local governments. An investor does not need to wait five years to see returns on investment. Little wonder then that thermal has so few takers now.

India's largest thermal power generators are following through on this financial logic. NTPC, the largest public sector power generator with installed coal plant capacity of 44.6GW, has decided it won't build any more new thermal plants. Unlike IPPs, NTPC signs priority agreements with both Coal India, the national miner, and the Indian Railways. Despite these cost advantages, NTPC is bowing out of the coal game.

Praveer Sinha, CEO of Tata Power, India's largest private power generator with installed thermal capacity of 6.8GW, has said his company will no longer invest in coal plants either. It will only buy existing distressed capacity through an investment platform created with ICICI Bank, and not risk its own equity in thermal power. This is how Tata Power indirectly acquired the 1980MW Prayagraj power plant in Uttar Pradesh last year, previously belonging to Jaiprakash Power Ventures Ltd, by taking over Rs 6000 crore of the plant's debt.

JSW Energy, part of Sajjan Jindal's business group whose interests span steel, cement and power, is reluctant to make new investments in the coal sector too. JSW Energy was built around the company's flagship Vijayanagar, Karnataka, factory in 2000, intended to support its neighbouring steel-making unit by providing off-grid power while also selling surplus to the state grid. Twenty years later, plant load factors are below 35% even though Vijayanagar continues to be the largest single-location steel plant in India. While the group has picked up distressed steel plants under the bankruptcy law and bad loan crisis, it is being much more hesitant with acquisitions in power. For instance, JSW Energy's plans to acquire the stressed 1050 MW GMR Kamalanga plant in Odisha has been abandoned. The JSW group has long-term plans to double steel-making capacity but is wary of which way to step when it comes to the future of its energy business.

Prashant Jain, Joint MD and CEO, JSW Energy, said: "I think the future of the power sector in in looking at grid and off-grid (solar pump, rooftop solar) demand separately. The power demand-to-GDP elasticity used to be 1:1 for the last 20 years. Going ahead, it will be hard to maintain this ratio. Of course, India's power demand will keep growing at 4-5% every year but I doubt grid demand will grow at the same place. And thermal power can be cost-efficient only if it supplies to the grid."

Why renewables have eclipsed thermal

In a head-to-head battle between coal and renewables, the latter wins on almost all counts. With a renewable project, whole power plants can be erected within 12-18 months. Input costs, imported mostly from off-brand Chinese manufacturers, are the lowest they have ever been. Meanwhile, global funds, from private equity and venture capital to pension funds, sovereign funds and university endowments, want to invest in green energy just as much as they do not want to invest in polluting fossil fuel projects in developing countries. The only advantage coal has it in plant efficiency: a well-constructed 100MW solar power plant operates at a utilisation level of under 30%; a 100MW thermal power plant can operate at upto 85-90%, as long as you keep feeding it enough coal or gas. The only way renewables can beat thermal outright is by setting up more renewable plants and increasing overall capacity.

There are other changes happening in the Indian power scene that give renewable projects and their investors a definite advantage. One of those is the emergence of new battery technology that can make large-scale power storage financially feasible. The International Renewable Energy Agency believes that utility-scale batteries - whether lithium ion or pumped storage - can enable greater feed-in of renewables into the grid. "Battery storage systems can provide instantaneous response to transmission-distribution network systems to manage any variability caused by generation from renewable energy sources," the agency said in a recent report. If these batteries are paired together with renewable power plants, they can together provide both cheap and reliable electricity. If the costs of battery storage can eventually fall below one-third of today's levels, investment decisions in new power capacity would change considerably, especially in India.

Battery technology is already attracting money. Venture capital funds - the primary category of investors in high-risk early-stage technologies - invested $2.3 billion in battery technology, smart gris and energy efficiency companies in 2019, according to data compiled by Mercom Capital Group. In 2018, $2.8 billion had been invested here. In September 2018. the World Bank committed to a $1 billion battery storage investment programme, of which $300 million has already gone into loans for the China Renewable Energy and Battery Storage Promotion Project,meant "to increase the integration and utilisation of renewable energy." The World Bank Group has also established a new international Energy Storage Partnership platform where countries can learn from the Chinese experience. Some experts believe that if electricity storage technologies do come up to scratch, India could see its thermal power generation plateau in 2030 while renewables and storage can provide reliable and affordable electricity for future generations.

The other change happening right now is the increasing popularity of energy trading in India. This happens through a "power exchange", much like a stock exchange where power suppliers can sell their generation to the highest bidder on the exchange. Once a trade is complete, the required units of power are fed into the grid and delivered to the buyer. Over the last year, trading activity on India's two main exchanges - Power Exchange India and India Energy Exchange - has increased and state-owned electricity boards, generally loath to make any changes to their existing operating structures, have gotten on board as well as they've found their energy costs fall by buying power off of exchanges.

Typically, power utilities sign two-part PPAs with thermal power generators. The fixed component of the tariff in the PPA has to be paid regardless of whether the distribution company (discom) procures power, and the variable component - which covers the cost of fuel, delivery etc - is paid only for the quantum of power purchased. In the past year, discoms have found that when the exchange-traded price falls below the variable component of their PPAs, they can save on their overall energy costs by ignoring the PPA and buying on the exchange directly. When the exchange price rises higher than the variable component, discoms can then return to procuring power under their PPA contracts. Thermal generators can supply their excess power on the exchange, increasing supply and lowering overall power costs for buyers. This trading mechanism brings free market economics to the power sector.

The launch of real-time trading in power exchanges this June - where buyers can place orders and have power delivered in under 60 minutes - has made large-scale purchases of power as simple as ordering a meal. The real-time market has already seen average prices fall to as low as Rs 1.55 a day, with some trades happening at as little as Rs 0.10 a unit. Granted the low prices come at a time when India's overall power demand has crashed during a 75-day national lockdown. However, this shift towards trade is here to stay.

In the fiscal year 2019-20, India's renewable energy sector (at 8.7GW) added more new capacity than the thermal energy sector (7GW), maintaining its lead for the third year in a row. Clean energy now accounts for close to one-fourth of the total installed energy capacity in the country. In the last five years, the share of renewable energy (wind, solar, biopower and small hydro) in installed capacity has increased from 11.8% (32 GW in March 2015) to 23.5% (87 GW in March 2020), according to credit research firm CARE Ratings. On the other hand, the share of thermal sources has been on the decline — from 61% to 54% in the same period.

It is true that there are several problems with this meteoric growth of the renewable energy sector in India, just as it is true that thermal power will remain the baseload power source in India for the forseeable future; too much money, both public and private, has gone into the sector to reverse the trend. So despite the daily headlines on new investments into renewable power, India remains among the top three public financiers of coal in the G20, pumping Rs 11,400 crore into the sector every year on average.

Renewables will not dislodge Big Coal, but the right policy push may force it be cleaner. If we are to look to a cleaner energy future, the answer doesn't lie in building more solar and wind farms. There are opportunities, which may be expensive and come with tariff implications, to make coal cleaner. Over the long-term, it will hard to justify burning fossil fuel the way we do today.

Finding Faultlines: Shining A Light On Wind And Solar

For the last few years, the renewable energy sector was the poster child for growth and investment in India. As its thermal counterpart fell out of favour – coal was expensive, polluting and couldn't pay back its loans; natural gas disappeared from the domestic market – everybody wanted to get in to the green energy game. India's installed green energy capacity stands at nearly 80 GW and was slated to cross 100GW by December 2022, definitely short of the government's 175GW target but not an insignificant achievement either.

But that breakneck pace of the last few years is now flagging. Solar energy tariffs in India are among the lowest in the world, but state governments are keen to push that down further. At the same time, these dangerously low tariffs are unsustainable without some developers cutting corners on quality. Some state power distribution companies (discoms), that nemesis of any power generator in India, are over 2 years late on paying their power bills. Developers in Andhra Pradesh are facing an existential crisis as the state holds them hostage to either lowering their old tariffs or stopping generation. And where there was once a steady stream of investment, that tap is now being turned off. Suzlon, the prominent wind power developer and turbine maker from as recently as 2016, has had to restructure its bank loans to save itself from insolvency.

Independent power developers (IPPs) were staring at a a slowdown this time last year. Of the 64GW that was auctioned by the Centre and states in FY19, 26% received no or lukewarm bids and another 10% went cancelled. Tariffs that states are willing to pay are capped at between Rs 2.5 and Rs 2.8, limiting the room for IPPs to improve their margins. Vinay Rustagi, MD of renewable consulting firm Bridge to India, said at the time: "In the last four months, there have been 11 wind and solar project auctions. Only two of these auctions have been fully subscribed – SECI (Solar Energy Corporation of India) Maharashtra 250 MW in May 2019 and SECI pan India 1,200 MW solar in June 2019. The other nine tenders have been heavily undersubscribed. There are many reasons for falling investor interest – increasing cost and risks associated with land acquisition plus transmission, tightening liquidity in the financial markets, and aggressive ceiling tariffs. There is also heightened risk awareness in the wake of mounting payment delays and PPA renegotiation attempts. None of these problems seems like going away anytime soon, so the bidding uncertainty may persist particularly if the government is keen on rushing out more capacity to auctions." For projects that have been won, the pace of execution has slowed down dramatically.

What has saved the sector, particularly solar power, from the brink of implosion is a flood of foreign capital and green energy funds benefiting from dirt-cheap global liquidity with very few options where it can make a decent buck. India's renewables sector has seen $2 billion of private equity investment in the last 18 months and another and another $4 billion into public debt investment. This capital inflow is taking the ownership of Indian renewable energy assets away from local developers to foreign investor-owned platforms. The largest local developers from a few years ago have sold either controlling or significant equity stake to overseas investors, injecting the latter with the cash necessary to place bids at lower and lower tariffs.

Mounting dues and shaky PPAs

In July 2019, YS Jaganmohan Reddy, the then newly elected Chief Minister of Andhra Pradesh, said solar and wind IPPs that provide power to the state would have to lower their tariffs or else see their long-term power purchase agreements (PPAs) cancelled. To understand the scale of that threat, consider that Andhra Pradesh, at 7.7GW, buys 9.6% of the renewable power generated in India. Like Gujarat in the north, Andhra Pradesh had, until then, led the growth of the industry in India. IPPs like the Hyderabad-based Greenko group, valued last at $6 billion and backed by sovereign investors such as Abu Dhabi Investment Authority and Singapore's GIC Holdings, were encouraged to set up their first plants there. IPPs like ACME Solar, ReNew Power and Mytrah Energy, among the biggest by capacity in the country, followed. In 2019, credit ratings agency Crisil has estimated that the state's decision affects 5.2GW of its installed power, placing Rs 21,000 crore of outstanding debt at risk of default.

The bone of contention for the state government is PPAs signed from 2014-2019 that were over and above the mandated 5% renewable power purchase obligations of the state. Before competitive bidding for awarding projects was introduced for the RE sector in 2017, states invited developers by setting a fixed tariff (called the feed-in tariff). Greenko's first plants in the state sell power at rates of Rs 5.74 per kWh (a unit), which appears to incense the current dispensation appears when prevailing solar tariffs have fallen to a low of Rs 2.44 a unit.

Add to this the fact that state discoms' dues are piling up. As of June 2020, state discoms owe a whopping Rs 10,030 crore to renewable energy companies, according to PRAAPTI, a Ministry of Power web portal that aggregates data on discoms. Some payments have stretched over 790-820 days from repeat offenders like Tamil Nadu, Telangana and Andhra Pradesh. On average across India, payment delays stretch over 12 months now.

Policy changes have been sudden and unpredictable in other states as well. Taking a cue from Andhra Pradesh, Uttar Pradesh and Punjab have made attempts to renegotiate old RE tariffs or threaten developers with curtailing purchases. Gujarat decided, last year, that only projects that supply power to the state discom could use land within Gujarat, flouting a central procurement agency's rule for setting up projects under the interstate transmission system. Rajasthan, one of the most sought after states for solar power plants, recently announced its intentions to charge Rs 2.5-5 lakh per MW on all projects that sell power outside the state. IPPs often delay setting up plants till they are sure that the transmission lines that will evacuate power from the plant to the grid are being built simultaneously as well.

Sanjiv Aggarwal, Partner – Energy, at Actis LLP is best-placed to discuss the current challenges of the sector. In 2014, when the sector was taking off in India, Actis set up Ostro Energy, started accumulating large scale solar plants across India. In 2018, Actis sold Ostro's 1.1GW of capacity to its competitor ReNew Power for $1.5 billion. Actis then launched its second renewable energy platform Sprng Energy, to repeat this process. Aggarwal heads this practice in India.

"We are fine with making large commitments to renewables," he said in an interview to Mint late last year. "In Sprng, we have committed close to half a billion dollars. Of that by the end of this year, we would have invested $300 million in cash and we have won PPAs of $450 million. The big challenges for the sector now are one, large single-site land acquisitions, since most projects are of at least 250MW capacity these days, and two, the availability of debt to build out projects. While the central government is more understanding of a developer's concerns, states are difficult to deal with. I have won a project of 250MW in Ananthapuram in March 2018 and a 500MW project in Kadapa in October 2019. The state is yet to sign the power sales agreements (PSA) for these but I've already paid the solar park charges of Rs 240 crore in cash for both these projects. This affects my internal rates of return from day 1. From an IPP's point of view, it puts a lot of stress on us.

"There are several hidden risks in solar," Aggarwal said. "There is the currency risk because modules are imported and then the cost of the module itself keeps varying. If the PSA adoption is delayed, my schedule goes into disarray. And lenders won't approve a project till PSA is signed."

For IPPs, the cash crunch is real and the stress is showing on the credit quality of their borrowings, causing many to turn to foreign investors for fresh equity. Last October, credit ratings agency ICRA revised the ratings of almost one-third of its renewable energy portfolio. It downgraded about 20% (1.9 GW) of its rated portfolio in wind and solar power segments and revised the rating outlook – indicative of troubled times ahead - for another 10% of the portfolio.

Smart money seeks quality plants

Despite the slowdown plaguing the broader economy, the financing tap for renewables sector has remained stable. Private equity investments into a sector that has run solely on this form of investment, have remained roughly the same in 2018 ($1.93 billion) and 2019 ($1.8 billion) but have fallen in the first half of this year ($ 254 million). However, the bulk of this has gone to large marquee names like the Greenko group, O2 Power, Adani Green Energy and Azure Power.

Like we can with equity, there is no clear data yet to measure the true scope of public lending to the sector. In the last three years, banks have had to write off large portions of their loan exposures after corporate borrowers failed to pay back loans. This was followed by the massive bankruptcy of Infrastructure Leasing and Financial Services in September 2018, which took down parts of the shadow lending sector with it. Large banks like State Bank of India are no longer lending to renewable energy projects that sell power at below Rs 3 a unit. Besides central agencies like Power Finance Corporation and Indian Renewable Energy Development Agency, private banks such as YES Bank and Axis Bank and non-banking financial firms such as L&T Financial Services, Aditya Birla Financial Services, Piramal Enterprises and Tata Cleantech were the primary lenders to the renewable energy sector, but even they have now become circumspect. Most lenders Mint spoke to declined to comment on-record on the health of their renewable energy exposures.

One private lender, on the condition of anonymity, told Mint: “With states like Andhra Pradesh reneging on contracts and the health of discoms being as abysmal as ever, several renewable energy firms are facing working capital pressures. Now, when I lend, I don’t want to take on projects in Andhra, Telangana or Uttar Pradesh any more. We are seeing a serious risk of default where these states are the counterparties. Till a year ago, we would probably turn away 5 of every 10 developers who approached us. Now, I turn away 7-8 of every 10.”

"With a delayed payment cycle and tariff ceilings, the internal rates of return for developers on many of these projects are going to be affected. They are seeing this fall from 15-16% earlier to 10-11% now, at which isn't worth the risks they are taking on," he added. "We want to be more conservative now, so we're asking developers to bring in more equity for new projects. Earlier, if we lent at a 75:25 debt-equity ratio, we now do this at 60:40."

Aggarwal of Actis said of the challenging debt environment now. "There is a fair bit of stress coming in because companies are under-capitalised and they have taken on mezzanine debt. Mezzanine debt is expensive debt to take on and you have to replace it with more equity down the road. But the public equity markets are shut and developers are all getting squeezed. People like us are well-funded on debt and equity and my projects are contracted with NTPC and SECI, who pay in 7-10 days. Between my time in Ostro and now Sprng, I can tell that the universe of lenders has shrunk. No public sector bank lends to renewables any more. The risk appetite has gone down and they are not happy with their exposure levels in renewables."

How good is this power?

An area of increasing concern is the quality of solar energy installations in India. Animesh Damani, Partner at Artha Energy Resources, a Mumbai-based renewable energy consultant and investment bank, points to early indications of poor quality plants being set up in India. "We have access to data on the performance of solar energy installations in a variety of states, and there is enough data available to show higher-than-expected degradation levels in the solar modules that Indian developers are using," Damani told Mint. "Usually, we assume an average annual degradation rate of 0.8%. That is, generation from an installed solar plant falls by 0.8% roughly for every year of operation. But we're now noticing that after a plant's fourth or fifth year in operation, the average annual degradation is as high as 2-3%. That's triple of the degradation rates that developers and lenders assume when they invest in a plant. For a good system, the average plant load factor

(PLF, a metric for power generation) should be between 20% and 22%. But we're seeing that by year 5 or 6 of operation, this falls massively to 14-15%."

Data collated by Artha Energy in over 50 solar energy projects operating for over 3 years - spread across Gujarat, Telangana, Andhra Pradesh and Rajasthan - shows the average generation from these plants falls by a minimum of 5% by the fourth year of operation. By the fifth year, the units that these plants generate fall by between 8% to as high as 30% sometimes.

While module degradation itself is not the sole reason for falling power generation from a solar energy plant (maintenance and transmission issues have not been considered here), there is a consistent drop in generation year over year while other assets in the same region are showing better generation.

The question of module reliability is now being raised more often that ever before. A 2018 all-India survey by a team of experts from IIT-Bombay on photovoltaic (PV) module reliability found significant variability in the quality and degradation rates of solar modules in India. "Many modules show excellent performance, but there are many others showing alarmingly high degradation rates," the survey found. Higher degradation is more common in newer plants set up in regions with higher than average temperatures.

"Crystalline-silicon modules (analysed in the survey) show an average linear degradation rate of 1.47 %/year, much higher than the international benchmark of 0.6-0.8 %/year,: the IIT-B study found. "Young modules (< 5 years) show higher degradation rates than old modules, pointing to poor quality and also perhaps over-rating of young modules in recent years..It is felt that some of the quality issues seen especially in the young modules are the result of aggressive pricing and timelines and improper handling/installation."The study warned that quality issues in solar PV cells could be the result of very aggressive pricing and commissioning deadlines for PV plants in India in recent years. It cautioned that due diligence should be exercised while selecting and procuring modules, including verifying the antecedents of the manufacturer, and independent checks on the quality of the modules imported into India.

"Indian developers rarely use tier-I panel manufacturers when setting up plants in India," Damani of Artha said. He is now setting up a platform for rooftop solar projects and is aware of quality discrepancies in modules that are imported into India. "A top quality Tier-I manufacturer such as REC or HanwhaQ or Canadian Solar would degrade at 0.8-0.9% even after 7 years, but we don't see much of these being used in India. Indian IPPs buy from second-tier or poor quality Tier-I Chinese manufacturers who sell modules at upwards of 30 cents to the US but at 22 cents to India. Hence, there is in-built incentive to alter the quality of these modules." Despite tariff barriers erected by the government, Chinese firms supply four of every five solar cells and modules used in India.

"Government quality norms on modules imported into India are not comprehensive," Damani added. "Nobody checks the purity of silicon being used in these modules we bring into India. If IPPs use the best quality of modules available in the market, it is not possible to produce solar power at the cheap tariffs that we see now. Most developers financially structure their plants for a payback period of 4-5 years but PPAs are signed for 25 years. There is no guarantee that these plants will keep generating power that long."

Damani saw this recently when overhauling an 8-year-old 1MW plant for a client, whom he cannot name for reasons of confidentiality. "The plant was initially generating 16.5-17 lakh units a year. By year 6, this had fallen to 11 lakh units and the panels were literally worthless. The IPP tried to replace the panels but by then, the original manufacturer had gone bust. We are now looking at replacing half the modules in the plant and the only reason this was possible was because the PPA - at Rs 18 a unit - was supportive and the IPP had the necessary capital."

India saw the maximum solar energy installations in 2014 and 2015; so these higher degradation rates still have a few years before they set in. “We’re clearly seeing a trend among developers choosing poorer quality of panels to support the low solar tariffs. I think in a couple of years, they will see the fallacy of their ways.”

Hidden costs

A large part of this stress in the renewable sector is because the rate of growth power demand, particularly from industry, has been slower than expected. Post covid-19, experts agree that growth in electricity demand will remain subdued; the shock may last up till 2025, according to some estimates.

The other looming question is the true cost of renewable power in India. Foreign investors have bankrolled recent reverse bidding auctions at SECI and brought prices down to an all-time low of Rs 2.36 a unit last month. Before this second coming of foreign capital this year, domestic developers had brought tariffs back up to Rs 2.7 a unit in central and state government auctions. Today interstate transmission is free for renewables because distribution companies bear the cost. In addition, since renewable energy plants run at only 20-40% load factors, utilities must also pay fixed charges to conventional power plants to supply the remaining load, which makes the full cost of this green power far higher - in the realm of Rs 5 per kWh - than what the reverse auctions reveal.

“If the economy was growing at a clip and demand for power was rising,” a senior industry executive who did not wish to be named told Mint, “then both the scale and tariff could be sustainable. Today, discoms are forced to buy expensive power and political pressures prevent them from raising tariffs for consumers. If the demand for power is slowing down, the ripple effect is going to keep showing up now and then in longer payment cycles and more standoffs between states and generators.”

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