Integrating Renewable Energy Into India's Grid—Harder Than It Looks

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Highlights

1. Grid integration is a key need for scaling Renewable Energy (RE) in India, not just to 175 GW (targeted for 2022) but far higher in the future. Integration isn't just a technical issue for grid management but impacts the holistic economics of RE.

2. Understanding system level costs of RE (rather, all supply options) is critical, which encompasses not just the generator costs (captured in Levelised Cost Of Energy, or LCOE numbers) but also transmission, balancing etc., that too at the margin (with location and time granularity) instead of just aggregate or average numbers. Contractual issues and Power Purchase Agreements (PPAs) also impact cash costs to system operators or utilities.

3. There haven't been sufficient studies on grid integration, especially ones that combine optimisation, economics, and risk. The main technical study has been the Greening the Grid (GTG) study, jointly undertaken by the US National Lab NREL, India's central grid operator POSOCO, and the Lawrence Berkeley National Lab (LBL) (under the aegis of USAID and the Ministry of Power). This is a unit-commitment scheduling optimisation study, which explicitly doesn't examine contractual economics of power plants, something state load dispatchers would need to worry about. The Central Electricity Authority (CEA) has a high-level analysis of system-level costs based on a couple of states, indicating current system level costs of RE are about Rs. 1.5/kWh today, mainly due to RE's impact on other generators, primarily coal.

4. The GTG study isn't attempting to "predict the future"–it's one specific and focused analysis on how to handle 175 GW of RE. The GTG study has limitations, most of which are known and transparently listed. The optimisation findings should be taken as a best-case scenario, and as we improve our understanding of the "real world", the costs and system impacts of 175 GW RE will likely be higher, especially given it's hard to improve operations better than as per an optimisation.

5. RE variability and coal plants' ability to change (flex) output may differ measurably than what is assumed by GTG. How much RE varies and how much coal plants can reduce output in response to RE are key factors affecting RE grid integration. In addition, potential emissions impact of SOx and NOx emissions of using thermal plants for balancing renewables is not considered. A number of factors might be measurably worse than assumed in the GTG base case, including the capability of coal power plants to flex (modify) their output, as well as the variability of RE, which is inherently unpredictable but has been modeled with smoothening that may be excessive. Both of these amplify the "best-case scenario" interpretation of the GTG study. Partly due to data limitations, RE in the base 2014 year was not measured but simulated; available data show that actual RE output variance was far higher than simulated.

6. Economics matters, which in turn depends on the frameworks. Any optimisation, even if improved with better input data and finer granularity, will not necessarily be how grid operators dispatch power plants given the current economic frameworks. Today, load dispatchers treat coal and RE plants differently in terms of fixed and variable costs. These frameworks mean there is far greater incentive to under-utilise RE compared to the levels indicated in optimisation models, which are based only on operational constraints and marginal costs. Such analyses also do not address tricky challenges of planning future capacity. In the future, technical feasibility of grid integration will not be the only challenge, rather the economics and frameworks.

7. Future studies should build on the GTG analysis by incorporating the above issues to the extent data are available. First, states must collect and integrate RE generation data, including backing down (curtailment) with granularity. Second, there must be a systematic and framework aligned analysis to quantify the "hidden" (rather, systems-level) costs of RE. This must clearly incorporate the economics and contractual issues. Ultimately, optimisation studies would become inputs to the next effort of determining the best instruments for managing these hidden costs, ranging from ancillary services, to storage, to Time of Day pricing, etc. It may even involve payments or compensation mechanisms to states that bear a disproportional burden for RE. At some point, future studies will have to go beyond 15-minute intervals, not just because of ramping issues in short timeframes but also because of grid concerns on transients and stability. Few models can capture unknown risks and low-probability events, such as fuel supply disruptions or shortages of water for cooling towers, and so these remain unavoidable concerns that strengthen the interpretation of any optimisation model to be "best-case".

   Interestingly, the 175 GW figure mostly aligns with RE's generation share close to a "no regrets" scenario, spurred by falling RE prices, where the generation share of RE in 2022 is close to solar's capacity utilisation factor (aka Plant Load Factor, or PLF). However, scaling RE even further, towards deep decarbonising of India's electricity system, is a much harder task, and will require a host of technical, policy, and regulatory improvements spanning storage, time of day pricing, and flexibility of both operations and of power purchase agreements.

   Continued efforts in these areas will leave fewer excuses for stakeholders who resist high RE due to decision-making that may appear rational today but is also based on uncertainty and unknowns. It's entirely possible under today's frameworks of power contracts and pricing that states' resisting RE is rational, but that's a different problem than blanket statements saying "RE is too expensive".

1. Introduction

Growing RE and its grid integration

Even before the Paris Accord on climate change, India unilaterally announced ambitious plans in 2014 to quadruple RE to 175 GW by 2022, something that required an annual growth (CAGR) of over 25 percent. Since then, growth has exploded, especially for grid-scale solar power, which is meant to be 100 of the 175 GW RE targeted.[1] This rapid growth in renewables will involve challenges for grid operations and have various implications on the finances of distribution companies (Discoms), consumer tariffs and incumbent power generating companies, especially traditional thermal power plants. Integrating renewables at this scale with limited impact on tariffs, low curtailment rates, and with stable grid operations will require careful technical studies and discussion of tradeoffs, instruments, and risk-allocation.

Many issues are at play. These top-down targets need conversion into state actions as they are ultimately the ones to pay for such energy through the distribution companies, or Discoms, the utilities that procure power from generators and retail it to consumers. For example, while solar is relatively evenly distributed across India,[2] wind power is especially concentrated in specific regions. This means that most RE plans show concentrated generation in a handful of states. Today, these states pay the bulk of the cost of grid integration. Spreading the costs of integration across the country will require improvements if not alternatives to existing institutions like the Renewable Energy Certificate (REC) mechanism, and augmenting the transmission infrastructure. Even if we had RPOs spread across all states equitably, these would not automatically cover grid integration costs unless we purposely design so. Expanding markets with larger balancing areas and with more flexible operations would help significantly.

Before the push for 175 GW of renewable power, India's coal generation rapidly expanded at more than double the rate of electricity demand in the country between FY 2011-17 (Figure 1 and Figure 2). The Indian power sector suddenly found itself in the unfamiliar territory of being "power surplus", especially at some times of the day or year, and based on the procurement chosen by Discoms. This capacity overhang is the main reason we've seen the plant load factors (PLF) of coal power plants falling from

1 For most of this paper, we focus on wind and solar, which are variable, and only dispatchable in one direction (they can be curtailed, but their output cannot be raised at will). They also constitute the overwhelming majority of RE targets (160 GW out of 175 GW of RE planned for 2022). Even within these, we focus mostly on grid-scale RE, unless stated otherwise.

2 While solar also displays some regional disparity in solar input (termed insolation), solar requires dedicated land, while wind can be co-located with other usages to some extent. Differences in availability of "spare" land make geographic divergence across states even higher.

73 percent just a few years ago to under 60 percent recently. There have also been minor issues of fuel availability and the rise of RE, which will only grow much higher in the future. Demand growth has also slowed down, some of which is structural (rise of services beyond manufacturing) and some due to energy efficiency.

Keeping all of this in perspective, renewable energy targets are not just ambitious but have profound implications on the system.[3] From 7 percent in FY2017, RE's share of gross generation would grow to about 19 percent by 2022 assuming the targets are met and there is medium overall demand growth. The implications aren't just on power system operations, but also costs of supply, and subsequently on Discom tariffs and financial health.

In this paper, we focus on the major knowledge gaps when it comes to planning for and adapting to the rapid expansion of renewable energy power in India. The note is structured as follows. In section 2, we give an overview of the power grid in India, and what the broad challenges of RE integration are. We identify major questions that need to be addressed by the government and the energy policy research community in terms of understanding the system-level costs of RE. In section 3, we discuss in some detail the results of Greening the Grid (GTG) report — an important effort in this direction. We summarise the salient features of this modeling exercise and their policy implications. We then discuss the assumptions and limitations of the GTG report. The last section concludes with a discussion on modeling and analytic gaps that could be addressed in the future.

[3] California's recent policy to make electricity 100% carbon-free by 2045 is by some measures even more ambitious, as the last portions of supply are the hardest to decarbonise. On the other hand, the time frame is much larger, requiring a slower annual growth of RE or other solutions than India's 2022 targets.

2. India's RE ambitions and grid integration challenges

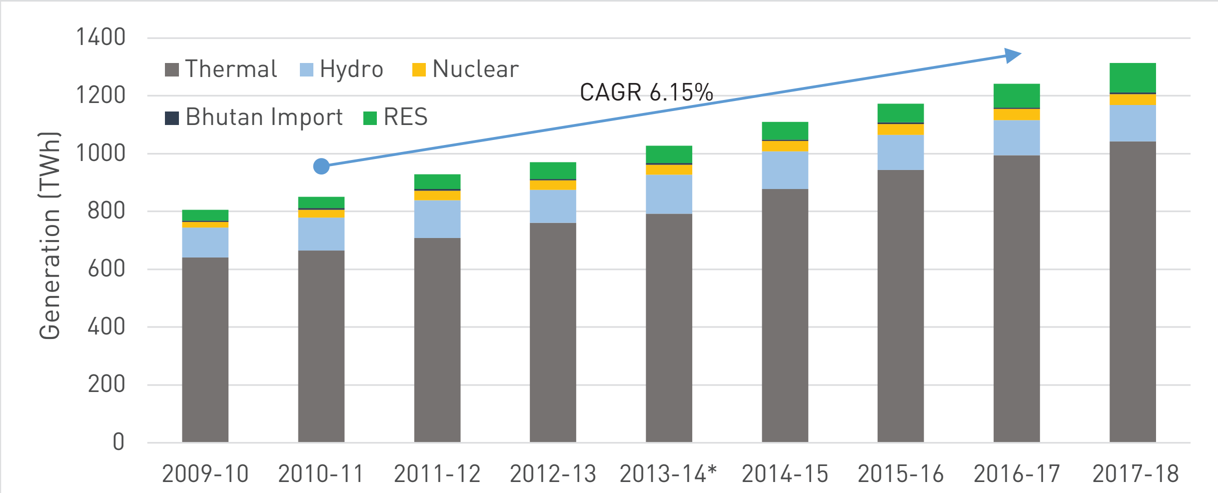
2.1 India's grid - High growth but not with RE in mind

India has a nationally unified synchronous grid, wherein theory power can go from any point to any point. In practice, there are transmission limits to shipping power point to point, say, to use the surplus wind of Tamil Nadu in Delhi. Operations are split across five regions which are more tightly integrated, with lower amounts of inter-regional transfer capability. This is not unusual when we examine large synchronous grids such as in the US and China.

After power sector reforms started in 1991, which opened up generation to private sector competition, states across India unbundled and created separate generators, transmission companies, and distribution companies. Each state is ultimately responsible for buying sufficient power to meet consumer demand, and also runs its own Load Dispatch Center (LDC) to choose which suppliers to call at what time to meet instantaneous demand. State LDCs coordinate closely with Regional LDCs, who manage inter-state flows of power. State LDCs not only worry about technical issues of keeping the grid in balance but also the economics as they aim to run the system at the lowest cost. This isn't a second-order challenge–almost 80 percent of electricity costs as seen by Discoms relate to power procurement.[4]

4 Power Finance Corporation's (PFC's) report on Performance of State Power Utilities 2015-16 http://www.pfcindia.com/DocumentRepository/ckfinder/files/Operations/Performance_Reports_of_State_Power_Utilities/1_Report%20on%20the%20Performance%20of%20State%20Power%20Utilities%202013-14%20to%202015-16.pdf

Figure 1: India's Electricity Generation by source



Thermal includes all fossil fuels but is predominantly coal. This is gross generation, excluding captive power. The CAGR of 6.15 percent is from FY 2011-17. RES = Renewable Energy Sources; TWh = terawatt-hours = Billion kWh or Billion Units (BU).

Source: Central Electricity Authority (CEA) Monthly Reports Executive Summaries, 2012-18[5]

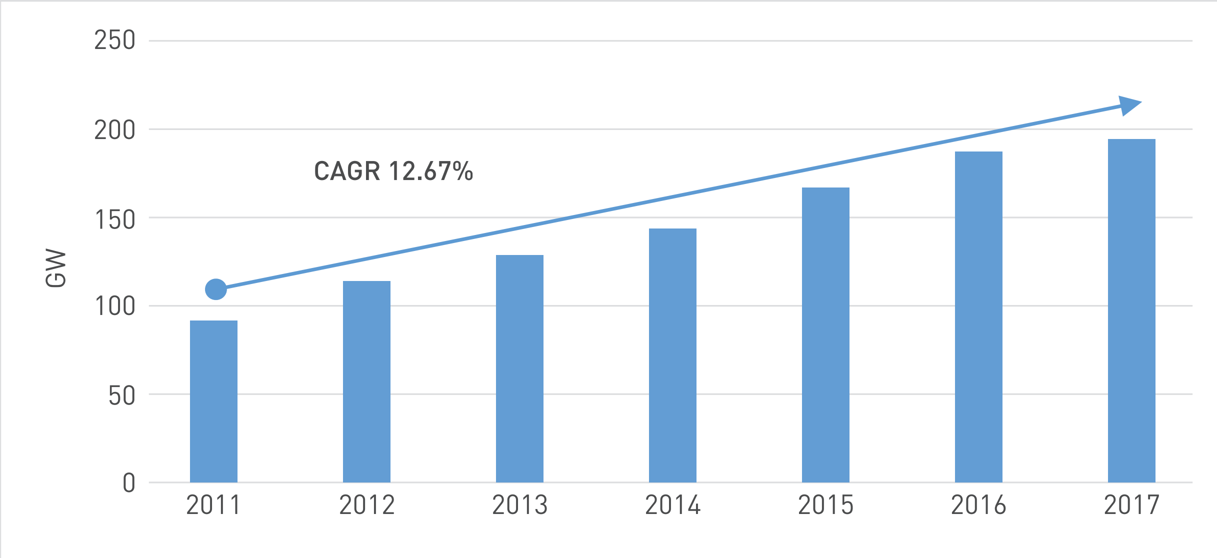
Until recently, RE was a limited if not a fringe player–even in FY2017 its share of overall generation was only 6.7 percent at a gross level, but the share is rising rapidly.[6] Most generation remains from coal (Figure 1). Recent strides in reduction of power shortfall have been not just because of improved grid operations or management, but a dramatic rise in generation capacity, especially coal-based. Between FY 2011-17, coal capacity grew by 12.67 percent (Figure 2), more than double the growth of power demand, which grew an estimated 6.15 percent as per CEA data.[7] This creates an overhang of coal-based capacity that will impact RE's operations and economics. Once a typical Power Purchase Agreement (PPA) is signed, Discoms are obligated to pay off the fixed costs of a coal generator regardless of its actual output. This means for an LDC, new RE may only be benchmarked economically with the variable (fuel) costs of coal in a narrow economic (cash) perspective.

5 CEA (2012-2018), Monthly Executive Summary for March, RE generation data from CEA Executive summary for April for the corresponding years: March 2012, https://bit.ly/2KTSVBp; March 2013, https://bit.ly/2JlatRd; April 2013, https://bit.ly/2mf0P9T; March 2014, https://bit.ly/2KPPGuG; April 2014, https://bit.ly/2mcyPU7; March 2015, https://bit.ly/2NKrF6l; April 2015, https://bit.ly/2NNg1aP.

6 RE's share by capacity was about 13 percent in FY 2017. This difference is because RE isn't just variable but also inherently limited in its expected output, with a Plant Load Factor (PLF), aka Capacity Utilisation Factor, of about 20 percent for solar and 30 percent for new wind. This assumes RE will always operate when available, and be absorbed. Given no fuel costs, RE is a virtually zero marginal cost "use it or lose it" source of power.

7 These figures are for utility-based generation and demand, including from Independent Power Producers (IPPs), but exclude captive power.

Figure 2: Coal-based generation capacity in India (excluding captive power)



Source: Central Electricity Authority (CEA) data

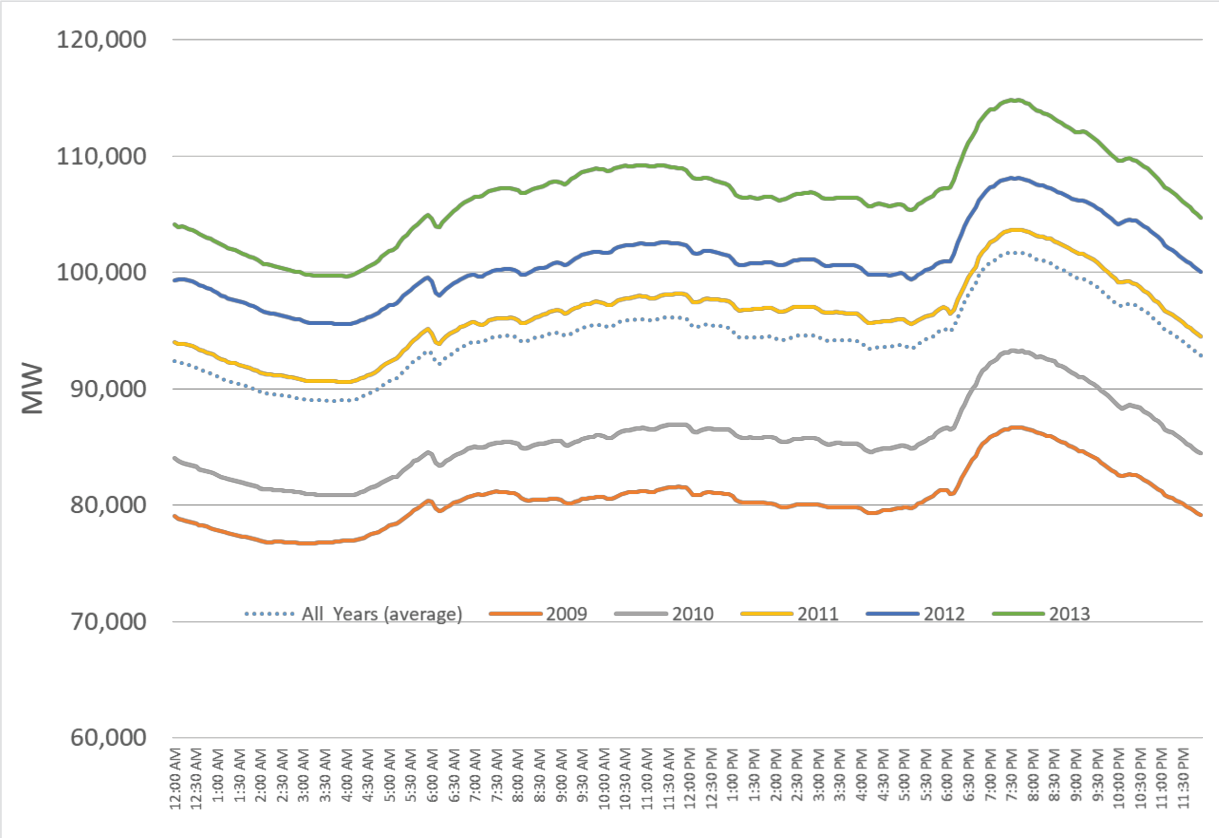
If all RE worldwide faces challenges of not just economics but variability and location-specificity, is India's grid any different? By many measures, despite rapid improvements, it is a weaker grid than in many nations or even compared to its own measures. The grid frequency, a measure of supply-demand mismatch, still varies much more than targeted, and there are limited grid reserves.[8] The 2005 National Electricity Plan asked for a modest generation margin of 5 percent,[9] which sometimes isn't present, while most developed countries have on the order of 15 percent or more supply margins.

It's worth unpacking what reserve margins mean. Today, since we have load-shedding and unmet (latent) demand, we don't really know the true demand. What we can measure is "load met" a.k.a. supply as measured at a particular point. (Figure 3) shows the national load curves across five years by the daily time of day (averaged). These are the supplies as visible to POSOCO, which are measured per state at the state grid level. What these mean is that Central Generation is captured post-inter-state losses (a few percent of such generation), while in-state generation is captured as net bus-bar before in-state transmission losses. Importantly, this is measured before distribution losses, which are over 20 percent today (a combination of technical and commercial losses). Thus, the consumption is far lower than this amount.

[8] Part of the challenge isn't power capacity per se (the overhand of coal means a fair amount of capacity) but availability of the right supply option at the right price (and time). Coal isn't a good reserve option, and natural gas is constrained by gas supply. Plus, India has never met all its demand, let alone latent demand, reductions in shortfall notwithstanding.

[9] Background is taken from CEA's National Electricity Plan Volume 1 (Generation), January 2018 (http://www.cea.nic.in/reports/committee/nep/nep_jan_2018.pdf).

Figure 3: Average daily system load curve aggregated across India



Individual days have higher variance between peak and off-peak demand, but the overall curve is quite flat (this figure expands the upper portion of the y-axis, to emphasise daily variances).
Source: NLDC data

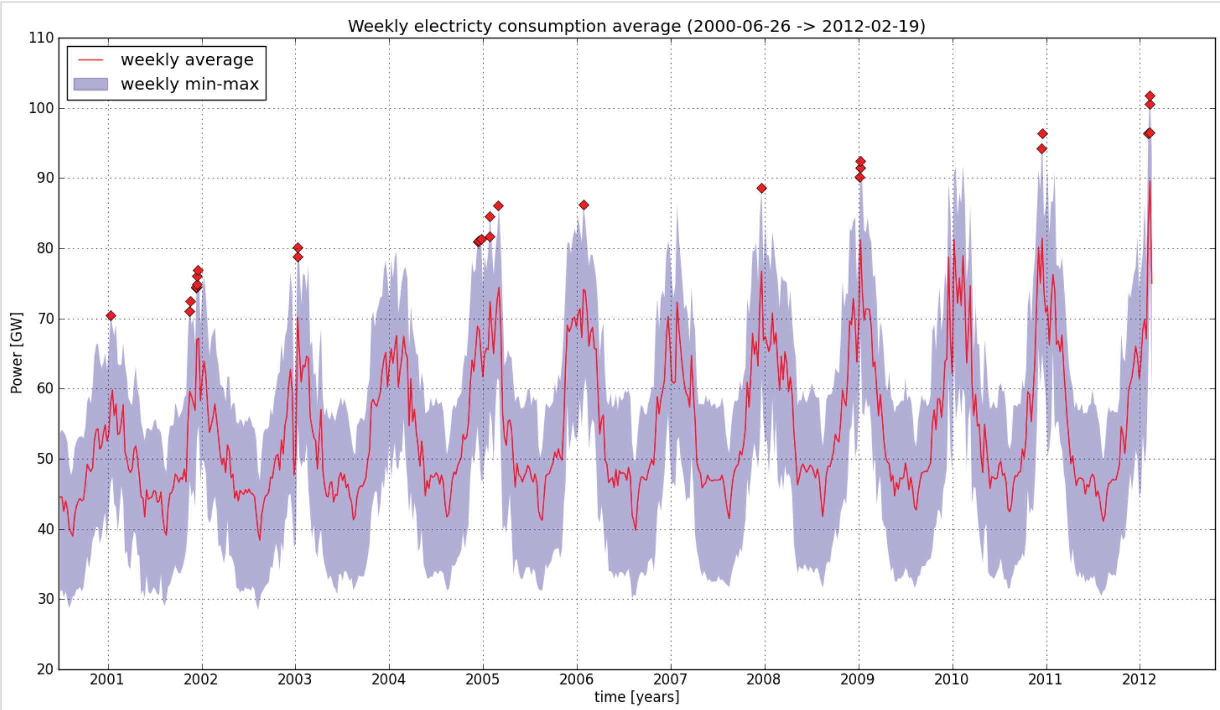
While these are the newest data we have available with such granularity, recent figures as seen in POSOCO reports are similar in shape, shifted upwards.[10] The daily load factor between 2008 and November 2015 is calculated at approximately 92 percent.[11] This report claims a high daily load factor is a positive. While that may have been true in a traditional grid, with high RE a demand peak matching supply could be a case where a lower daily load factor may be superior.

[10] The flatness of India's load curve can have multiple reasons, only some of which may continue as-is in the future. The peak was clipped (especially in prior years) due to load-shedding, which is now markedly lower. Agriculture was supplied at off-peak periods, especially night, but its growth may be lower than overall demand growth. Lastly, it is possible that as discretionary incomes rise, and use of appliances proliferates, the peak demand may grow.

[11] "Electricity Load Factor in Indian Power System". POSOCO, January 2016. Available at https://posoco.in/download/electricity-load-factor-in-india-power-system/?wpdmdl=709

The peak "load met" in India is only on the order of 165 GW as of 2017, which is far, far lower than the nameplate generation capacity of the then 330 GW supply. This is because of a number of factors discussed below. It's also worth noting how flat the demand curves are–the spread between peak and off-peak demand on a daily basis are only in the order of 10-15 percent, much lower than in other countries. Figure 4 shows French load curves, compressed to show weekly highs and lows over time. The claim isn't that one load curve is or isn't "superior"–it depends a lot on what supply looks like, but just a flag that (a) India's load curve is quite flat, and (b) it may evolve with a much higher peak. Such relative flatness of demand (rather, load met) in India hurts solar power, which would benefit from more demand in the day compared to the night. The worst case is when the relative flatness gives way to even more pronounced evening peaks, which is not when solar can produce.

Figure 4: Weekly load profiles in France



This is based on public data with 15-minute time steps. Red squares show the evolving frontier of peak load. As compiled by Pierre Haessig

(Source: http://pierreh.eu/electricity-consumption-peaks/)

Out of the 330 GW, about 55 GW was RE, which may not be available at particular times.[12] If we aim for 160 GW of wind and solar by 2022, that's a measurable fraction of expected supply at state borders needed at, say, 12 noon, the solar peak, when some times of the year wind may be near its own maximum output. While by 2022 the noon demand may rise perhaps 20-25 percent from 2018, we also have to factor in that we can't shut off all other sources of power. Nuclear is usually must-run when feasible, and even coal-plants cannot be switched off entirely for short durations–doing so not only has a cost implication, these plants can also take hours to turn back on. The entire details of the technical limits of RE are beyond the scope of this paper, but suffice to say, while this is a serious issue for all grids, India's share of RE planned by 2022 is exceptionally high when compared to "load met" as defined above. This will only worsen as RE rises further–at some point storage solutions may become necessary, else there is a higher risk of curtailment.[13]

These figures are national–for some RE-rich states, "too much RE" is already high, for which the solutions are only to either deploy storage technologies (limited and expensive today), to ship power to other states (necessitating sufficient transmission, which has a cost),[14] or to throw away RE ("curtailment"). After national RE rises enough, adding more transmission will not suffice.

2.2 Accounting for system level costs of RE

Transmission is only the first of many implications of higher RE. Let's leave aside discussions of which is cheaper–RE or coal–most calculations are only for up-front (generator) costs, often captured as the LCOE.[15] Even injecting RE (or any lower-merit-order generation) into a system can raise costs of other generators, who have to lower their output, not to mention face lower prices in case there is a market mechanism at play. Lowering the output of coal plants causes not just wear and tear but also lowers the

[12] India is unique in listing gross generation capacity, and not net bus-bar capacity. This inflates the capacity as thermal power plants lose about 7 percent of their output as auxiliary consumption in-house. This isn't just to run the lights or ACs —most are for running process equipment including pumps/compressors. Much of the remainder of the difference is because of a combination of plants under maintenance, unscheduled unavailability (including water reserve limits for hydro), or sheer non-usability of plants, especially older ones.

[13] Small amounts of curtailment may be cheaper than storage, especially if used infrequently.

[14] The government is planning "Green Corridors" aka large-scale transmission to handle high RE. While these can help ship power long distances, given these may have a low PLF if dedicated for RE, the costs of transmission could easily be Rs. 1/kWh above and beyond today's average transmission costs. This is before considering technical challenges of varying utilisation of transmission lines in terms of reactive power flows.

[15] RE no longer receives an explicit subsidy such as Viability Gap Funding, but many solar parks have aggregated or discounted access to land, or support for the same, a significant challenge for any large power project. Coal also pays heavily in taxes/levies/etc. and over-payment to Railways, perhaps on the order of 40 percent of delivered costs of coal across India (see Kamboj and Tongia for more details, "Indian Railways and coal: An unsustainable interdependency" at https://www.brookings.edu/research/indian-railways-and-coal/). In fact, the "coal cess" (presently Rs. 400/tonne) began as a clean energy levy on coal to help fund clean energy.

thermal efficiency of such plants and increases SOx and NOx emissions. While there are guidelines to compensate coal plants for lower output and to operate flexibly ("flexing"), these appear lower than the costs, especially for generators never designed for lower outputs, i.e., older ones. Scenarios within the GTG study indicate what are the lower cost options to reduce operations of some of these older coal plants, but the study doesn't quite get into issues of plant retirement. That is a complex issue which also depends not just on contracts and financing issues, but also compliance (or inability to cost-effectively comply) with upcoming pollution emissions norms.

Grid integration goes beyond a generator's Levelised Cost of Energy (LCOE)–the main marker for costs as bid out. LCOE ignores system-level costs such as the transmission requirements, or the impact on other generators, or even need for alternatives that can step-in at short notice with fast ramping capabilities. LCOE does not factor in state of the grid or Time of Day–these assume any power generated can and will be absorbed. It goes without saying that RE power and coal-based power aren't comparable–the latter is dispatchable and controllable within bounds, and suitable for baseload power.

CEA's December 2017 study[16] on such costs of RE estimated the impact to be about Rs. 1.5/kWh of RE. This is very high compared to bid LCOE costs of about Rs. 2.5/kWh seen today. While some of these costs would come down over time as the grid strengthens, and RE costs fall, some of these may get worse as RE's share rises. As and when we need to add storage to the mix, this will raise costs measurably, the alternative being curtailment risks. Integration costs are a complex issue, depending not just on what is being added (e.g., RE) but also what the rest of the grid looks like. Thus, any number will be indicative of a particular state of the grid only.

Calculating system level costs are further trickier when we consider alternative frameworks of costing. From an LDC perspective today, RE only imposes average costs (fuel costs are zero), so not dispatching it can appear cheaper than paying the fuel-only incremental costs of a coal-station. While this distortion should go away, since pure marginal cost analysis would dictate RE should become de-facto "must-run", it's a very different calculation when we compare building a new RE plant versus running an under-utilised existing coal plant more.

"What's the cheapest way to integrate 175 GW RE?" Is a very different question than creating a cost-curve for RE's "extra costs" as its share increases in the grid. If we had the latter, we could take a call on

[16] "Report of the Technical Committee on Study of Optimal Location of Various Types of Balancing Energy Sources/Energy Storage Devices to Facilitate Grid Integration of Renewable Energy Sources and Associated Issues", CEA, December 2017, available at www.cea.nic.in/reports/others/planning/resd/resd_comm_reports/report.pdf

how much is "optimal" or can be borne by consumers at a finite/chosen cost. This latter curve will also be dynamic, changing as the grid evolves. On one hand, hydro's share is likely to fall further, due to limits on its growth. On the other hand, the grid is becoming stronger and smarter, which will increase the ability to absorb more RE. One fundamental challenge is that as you grow RE, its marginal value declines as you are now displacing cheaper and cheaper alternatives. This is not an easy calculation, since location matters, both from a dispatch (including contractual) reason as well as keeping transmission constraints in mind. The GTG study was the first such attempt and was remarkable for not merely modeling generation units but also extending the analysis to transmission capacities.

2.3 Knowledge gaps for scaling RE

Given this background, we list some major questions that affect policymakers, practitioners and researchers alike when it comes to the integration of renewables at the order envisaged. Some issues are theoretical, i.e., there is not universal agreement on optimal pricing signals or market design. Other issues are more practical or case-specific, such as the contracting norms, e.g., treating RE with a single tariff differently than thermal plants with two-part tariffs in PPAs, separately fixed and variable costs. There is also an issue in terms of data availability and access–certainly scholars do not have open access to sufficient data, even if such data are available with the government, utilities, or grid operators. Instrumentation of grid-scale RE is relatively easy–rooftop or behind-the-meter PV is especially hard to measure and disseminate.

A few additional unknowns include:

1. **Technical unknowns of RE performance and supply/demand, including spatial and temporal heterogeneity**

    a. Where will the added capacity be located?
    b. How much will be grid-scale versus end-user (behind-the-meter) RE?
    c. What will be the expected performance (output) of RE?
    d. How much and where does transmission need to be augmented to mitigate balancing risks and curtailment risks?
    e. What will be the utilisation factor for the new transmission capacity?
    f. How will the load (demand) curve evolve? Will the peak demand shift? Will the peak grow faster than the average? How will mid-day demand grow vis-à-vis overall and peak growth?
    g. What are the reductions in emissions from thermal units due to higher RE? Would we witness higher emissions due to partial load operations and frequent ramping of thermal units?

2. **Grid Balancing and management unknowns**
    a. What are the non-internalised (system-level) costs of higher RE? How do the costs of RE integration vary as RE's share increases (the "RE integration curve")?
    b. What are grid integration costs for all forms of generation, with a breakdown by type of generation and some measure of location? A better framing might be how will the balancing and management costs of higher RE evolve? How will these change over time (based on assumptions of what the rest of grid looks like and applicable frameworks)? What is the value of flexible generation and of broader ancillary services (beyond frequency support ancillary services)?
    c. What are the technical capability and economic as well as environmental implications of flexing thermal units? How does this vary?
    d. What is the role of energy storage and of demand response to meet flexing and peak management?
    e. Will load-shedding continue or be allowed? What additional planning and system changes are required to better handle higher RE in a manner that doesn't increase the risk.
    f. If RE curtailment is either cost-effective and/or unavoidable, what are the quantum and cost implications? How are these to be borne by RE generators (or the Discoms)?
    g. To what extent can or will 5-minute dispatch and Wide Area Management Systems (WAMS) help RE integration?

3. **Contractual, regulatory, and policy unknowns**
    a. How will the costs of higher RE be shared across states? Will costs of supply and tariffs go up in some states more than others due to RE generation?
    b. Will the current norm of PPAs continue, or how will more flexible instruments evolve, including market mechanisms? Will there be a continuation of single part (for RE) versus two-part tariffs for thermal generators (fixed and variable)? What are the options for modifying and/or renegotiating PPAs?
    c. Will there be a time-varying price for power procurement? Will this extend to retail consumers? (Note: The two can be undertaken independently, and we believe wholesale ToD pricing is easier infrastructure-wise than retail ToD pricing. The latter need not be real-time or near-real-time, relying instead on time blocks or periods.)
    d. Will the grid evolve to signal local and near-instantaneous pricing, for example, through Locational Marginal Pricing (which blends supply, demand, and transmission states into location-specific pricing signals)?
    e. Will RE continue as a "must-run" resource?
    f. How might environmental emissions norms and corresponding equipment impact thermal unit costs, operations, and merit order?
    g. What are the economic implications of displacing thermal generation (including falling PLFs)? Is there a link to higher risk of stressed or stranded assets?

For many of these, there are subtle issues where it's not easy to predict or model the future. How much capacity comes up, where, at what price, etc. could be determined by the invisible hand of a free market. On the other hand, policy directives often nudge if not drive markets in specific directions (and in some cases dominate markets). Figuring out the optimal intersection and balance between markets and policy guidance will be an exercise worthy of deliberation and even experimentation.

These are difficult issues that need deeper analysis, and many issues are interlinked. Some of these can be simulated or modeled, but some are not amenable to optimisation but rather have a range of choices based on risk appetite, investments, and even path dependency. This is before considering developments in other aspects of the ecosystem, for example, the railway's transportation pricing for coal, or the push towards electric vehicles. There are also issues of jurisdiction and scope–national vs. regional vs. state-level analyses can lead to different results. Ultimately, all analysis should clearly delineate the technical feasibility of options and identify policy, financial, or contractual limitations that should be rectified. GTG identified a number of such issues.

3. GTG analysis–Useful insights, but based on debate-worthy assumptions and acknowledged limitations

The Greening the Grid (GTG) study was a ground-breaking analysis of grid integration, with multiple stakeholders providing inputs and experts across the US and India collaborating. This section is less a critique of the Greening the Grid (GTG) study than an assessment of what it does or doesn't say, and leading to suggestions on where future effort needs to focus.[17] If someone interprets that the key takeaway from the study is that there is "no problem" handling 175 GW of RE, that's a distorted, if not an incorrect, reading of the analysis, and not one the authors claimed either. The better interpretation is focusing on key things that matter, such as figuring out larger and better control/balancing areas, as well as increasing the flexibility of all plants to be more nimble and respond to the extent that they can.

3.1 GTG report summary

The Greening the Grid initiative is "co-led by the Ministry of Power and US Agency for International Development (USAID)", and the primary authors of the study are the US National Renewable Energy Laboratory (NREL), Power System Operation Corporation Ltd. (POSOCO), and the Lawrence Berkeley National Lab (LBL). In addition, representatives from various State Load Dispatch Centers, the Central Electricity Authority, and POWERGRID (the central transmission authority). As a result, the report has been prepared through extensive consultation and dialogue between power sector experts from the government and independent researchers from NREL, and many other stakeholders.

The GTG study states two primary objectives, viz., studying how to optimise the operations of a power system with increased solar and wind generation (175 GW RE by 2022, specifically with 100 GW or solar and 60 GW of wind), and evaluating strategies to improve RE integration.

[17] The study is available online at https://www.nrel.gov/analysis/india-renewable-integration-study.html

Fundamentally, GTG is an operations optimisation study, technically termed a unit-commitment analysis. The analysis estimates electricity demand in the future (2022) based on a simple extrapolation from 2014, which makes assumptions on generation capacities and properties (such as how much plants can output, ramp up/down, and what the marginal costs are), and transmission constraints. The report acknowledges current practices of treating RE as "must run" but operationalises this via zero marginal costs, which means it shouldn't be curtailed (thrown away) unless there is nothing else that can be backed down. For the national study, there is no significant storage capability envisaged.

RE generation in 2022 is modeled for different scenarios, including "100 S- 60 W" or 100 GW of solar and 60 GW of wind capacity additions by 2022 as per the national target. Renewable generation over the course of the year is based on 2014 RE resource data on supply over the course of the year. The study then estimates demand in 2022 in 15-minute blocks and determines the optimal generation mix in each of these blocks based on the availability and variable costs of each generation source. In the case of renewables, the study also simulates predicted and actual generation.

We summarise a few major findings from the study for the core scenario of 100 GW solar–60 GW wind, consistent with national targets for 2022:

- Integration of 100 GW solar and 60 GW wind at 15-minute timescales is technically feasible with minimal curtailment (1.4 percent) and without major changes to the transmission infrastructure beyond what has already been planned

- Increasing supply dispatch optimisation to the regional (or, national) level through improved coordination would show substantial operations cost savings of 2.8 percent (3.5 percent for national)

- The biggest driver to minimise RE curtailment is reducing minimum generation levels of coal power plants to 55 percent from the current 70 percent, i.e., making them capable of reducing output even more.

- The planned 2022 generation fleet can balance peak ramping requirements assuming all generators ramp to the full extent their technology allows, with hydropower playing an important role in maintaining system balance.

- Investing in battery storage for the purposes of balancing is not essential. For the 15-minute time periods modeled, batteries do not substantially displace coal power generation and benefits in terms of reduced curtailment rates are negated by efficiency losses.

- About 20 percent of the installed capacity of coal power plants operates less than 15 percent of the time and can be retired with insignificant effect on system operations.

The GTG report briefly discusses institutional challenges and capacity building efforts needed to optimally run supply dispatch. After the national and regional studies, this was followed up with state-centric analyses for the main RE-rich states to examine technical operations and grid implications. A companion report that focuses on regulatory and other institutional issues was released in March 2017[18] and a report on contractual issues is expected to be released shortly.

3.2 Discussion of the GTG study

The GTG study is explicit and transparent on its assumptions and limitations, but unless one is a domain expert and goes through all the details, one may miss what is expected, and correct, limitations of the study. Unfortunately, the data used is not available publicly, even in aggregate, but an online tool[19] allows us to see reasonable levels of outputs and assumptions.

Of course, any study examining the grid in 2022 will have to make assumptions, especially with a starting point for analysis from 2014 (hindsight is always convenient, even as early as 2018). Where within India will future RE (or other) capacity grow? Where will demand grow, by how much, and at what times of day? These are important questions that no one can predict accurately, and so the GTG study started with simple but reasonable extrapolations from 2014, following indicative government plans for where the RE growth may come. The results should only be viewed as a starting point for what may happen in 2022. Probably the biggest limitations, which future studies can address, are ones of methodology as well as assumptions that may be unrealistic or impractical in the real world, and these have specific implications on the findings. Unlike random uncertainty, where we have error bars around the result, some of these issues inherently will have a directionality in terms of their impact on outputs.

Being an optimisation, this is how the system should behave–it doesn't quite tell us how the grid behaves in the real world, with numerous other reasons for deviations from ideal conditions, not least because of economic reasons (a point acknowledged as a limitation of the study). Note that the economics is always based on a framework. While merit-order-dispatch (choosing which plants to use based on their variable costs) would put RE at the front of the line, with zero fuel costs, on a cash accounting basis, for states who anyways have to pay the coal's fixed costs today, adding new RE often becomes more expensive on an overall cash basis compared to using existing thermal capacity for more output.

[18] Regulatory Dimensions to Renewable Energy Forecasting, Scheduling, and Balancing In India: Regulatory Practices Analysis And Primer. https://pdf.usaid.gov/pdf_docs/PA00MNH3.pdf

[19] https://maps.nrel.gov/IndiaGTG/

To use a stock market analogy, like with any optimisation, the study is "priced to perfection"–everything goes as planned. Every deviation from designs or plans means one moves away from the optimisation. In addition to the issues raised above, and many more already flagged in the study as risks or unknowns (but not factored in for the model calculations, such as water availability), there are several issues that can make a material difference.

Our paper does not and cannot capture a full technical critique of the GTG study. GTG and similar analyses depend heavily on assumptions, and a number of these are not publicly available. For example, with days of very high RE, the only way the system can balance is if thermal plants not only flex down to 55 percent but some shut down entirely, or run in daily two-shift operations (a possibility not allowed in GTG calculations, which study authors clarified specify a 24-hour period of minimum uptime or downtime for a coal plant). Technical issues aside, there is a cost to flexing, let alone start-stop operations. Discussions with experts indicate a wide range of costs for stop-start. However, it appears the GTG study uses a single figure for the costs of a start-up. Whose figure(s) do you use? Some plants will invariably have higher costs of stop-start, not to mention flexing.

However, in this paper, we focus on what we consider to be two major features of the model: RE variability as modeled, and the feasibility of flexing thermal power plants.

3.3 RE's output may not be as smooth as modeled by GTG

The data and the modeling are only for every 15-minutes, while RE supply can change in less than 1-minute, especially with cloud covers on solar.[20] This model wasn't focused on studying very short timescales related to transient load flows or even grid stability, key issues for grid operators. More importantly, the study does not use actual RE output for 2014, rather using solar and wind meso-scale (multi-kilometer grid size) modeling of RE potential to estimate the production of wind and solar in 2014 and then extrapolating these to 2022 based on nameplate installed capacities. This is likely because such data wasn't and perhaps still isn't easily available.

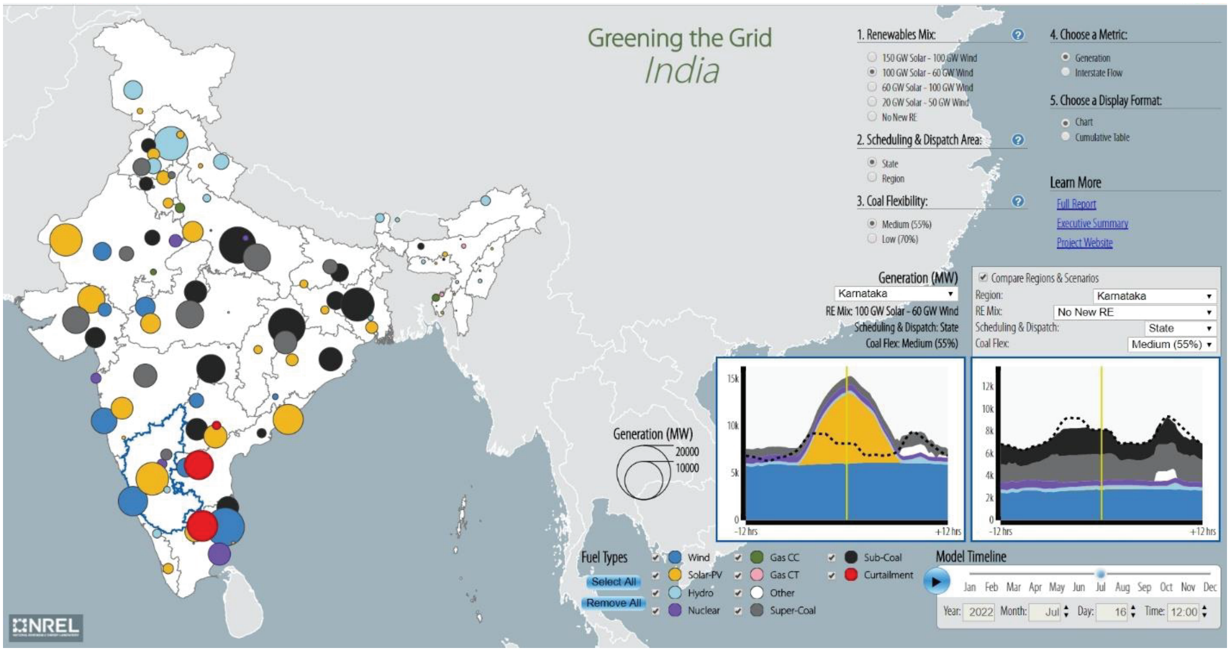
There is also a technical reason why this is an accepted methodology. Since future predictions will always have an instantaneous error, and this allows a consistency between supply and demand extrapolations to 2022, and also factors in the output from future RE plant sites, not just existing locations. A better analysis would combine such data with more years of weather patterns (for modeling) and actual RE output as well.

[20] Wind resource modeling in GTG was with 5-minute intervals, and solar with 60-minute intervals, linearly extrapolated or interpolated to 15-minute time blocks.

While more data is always better for analysis and baselining, the GTG report appears to use only a single year for simulation due to time and resource limitations, also pointing out that wind and solar are not truly independent, so using multiple years of separate wind and solar data can lead to errors. While this may be true, we are not convinced sophisticated data and training techniques aren't superior in capturing such correlations while providing a wider base of data points for the ranges of outputs. Even if a simple analysis using multiple years' background data leads to errors in wind and solar correlations, we posit it may compensate for correlation issues through the higher ranges of RE production it spans. After all, 2014 (or any single year) may be an outlier. Issues of outliers aren't just for RE output–the monsoon varies a lot, and hydro plays a particularly important role in grid balancing, due to its flexibility.

(Figure 5) shows GTG's windy day output for the state of Karnataka in 2014 and 2022. Note how smooth the output is (and this is the case for multiple days in this simulation), and near the nameplate wind capacity. Of course, there are many days where the output does vary a lot, but actual RE production data for 2014-16 find few days of such smoothness as modeled.

Figure 5: Snapshot of GTG results

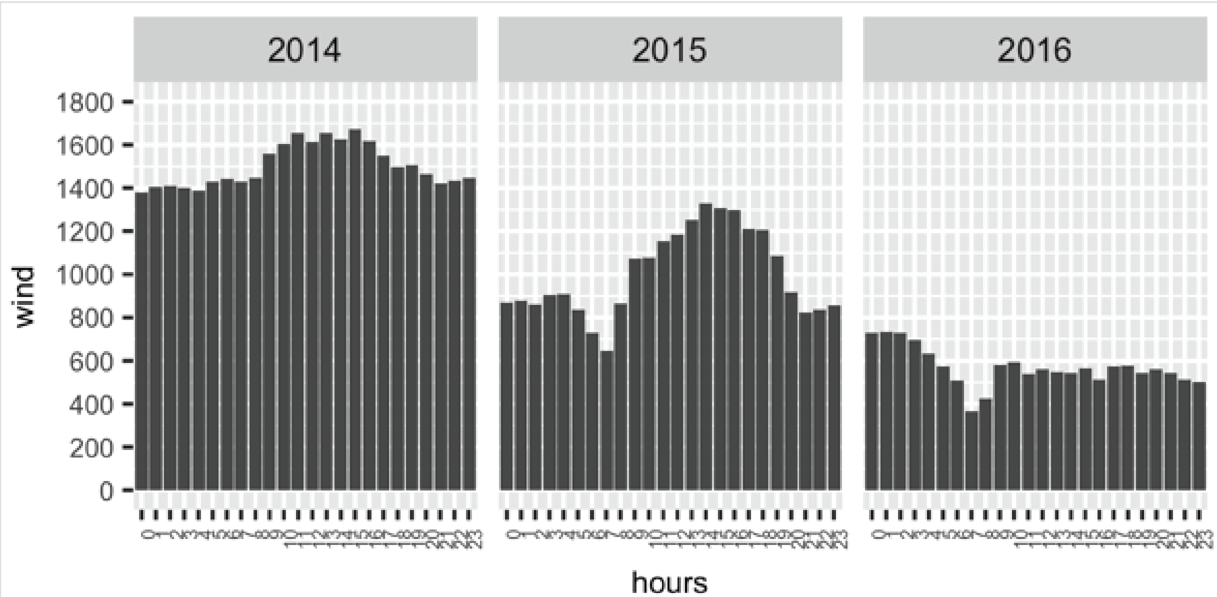


This shows 2014 estimated and projected 2022 output for the state of Karnataka. The dotted line is the state demand, showing that by 2022, the state is expected to be RE-surplus. The chosen day is a random "windy day" and many days in this month have similar curves.

Source: https://maps.nrel.gov/IndiaGTG/

In contrast, consider the actual full-state wind output for 2014, 2015, and 2016 on that same day (Figure 6). Not only is it far more variable, but it is also measurably lower than estimated, declining in some years (due to stochasticity). Solar is also shown as very smooth in output. While on average it may be smooth, for any given day it can be less smooth, even at a state level, especially if the state has large solar parks. Higher variability implies the balancing requirements and the need for coal to be further burdened (up and down) will be higher.

Figure 6: Actual wind output for July 16 in Karnataka

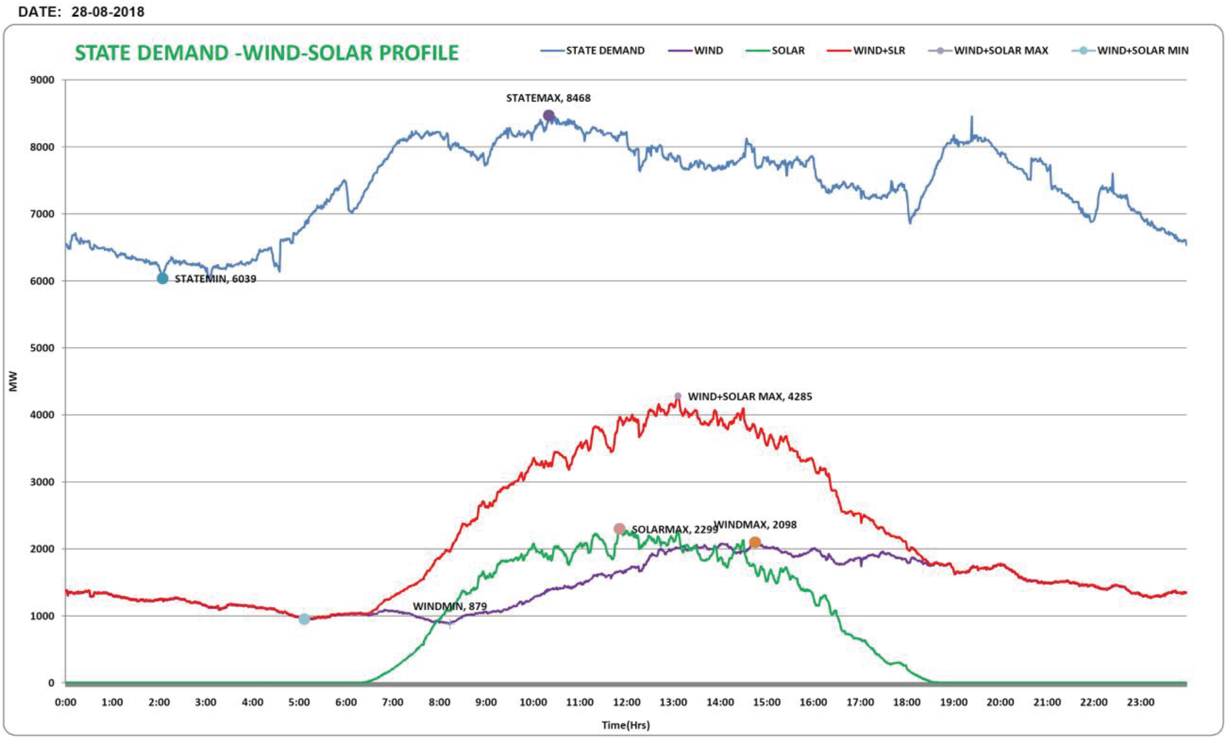


This is the same day as shown in (Figure 5). The decrease over time isn't meant to claim a secular decline– this is likely just stochasticity at play.

Source: KTPCL data

Solar is assumed to be less variable than wind, and this is true with a modest time period in mind, but short-term variations can be very high, even aggregated at a state level. An August 2018 single day snapshot for Karnataka (Figure 7) shows even at a full-state level, aggregate solar can vary. Karnataka has chosen to move away from large solar parks with such variability in mind. It remains to be seen how and in what form and where national RE growth will take place–its size, scale, and geographic distribution.

Figure 7: Sample daily Karnataka RE output and demand curve

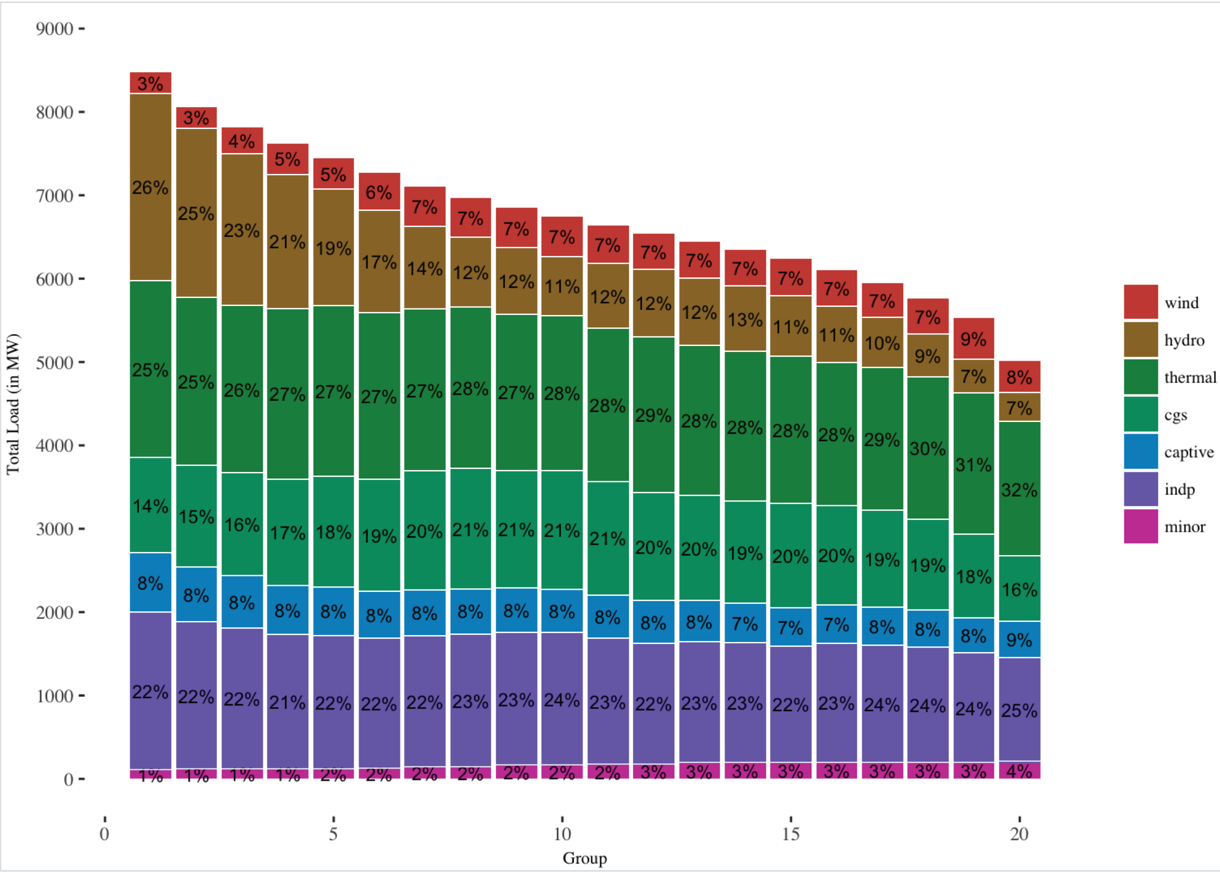


Source: KPTCL SLDC

Some of the differences between the GTG model and actual data depend on things we cannot predict, including whether all future wind turbines will be of the same hub height (and thus more correlated in outputs), not to mention their location. We are not sure if higher RE capacity would mean sufficient geographic diversity within the state–there are already multiple wind regions across Karnataka. The actual RE output data may be lower than modeled due to RE curtailment, but speaking with SLDC officials, RE curtailment was reported to be very low in those years, especially in 2014. While curtailment may lower the output, it may also lead to less smooth outputs, especially if off-peak demand periods are more curtailed. Of course, thinking beyond a single state with a larger balancing area will help, and likely improve diversity of RE. On the other hand, we believe (and have limited data for southern Indian states) that while larger balancing areas help, from an RE supply diversity perspective there are limits. For example, at the end of September 2018, in the evening (near the daily peak demand) the total national RE output is about 1.7 GW, or just over 1 percent of the load met.

Not only do we have supply variability to contend with, but demand itself varies. What is not always well modeled is how RE supply can be highly negatively correlated with state demand (Figure 8). What this means is we have to have other capacity to meet the peak demand, at which point adding RE disproportionately provides energy value, but not capacity value. Importantly, as acknowledged by the authors, GTG type of modeling is for how to operate the grid at lowest cost within technical bounds. It does not guide what investments are optimal or required, i.e., should one be building generation source "X" or not.[21] Due to the overhang of coal capacity (Figure 2), this isn't an academic question–the coal capacity already exists, and must be paid off.

Figure 8: Supply versus Demand by generator type for Karnataka (2016)



This breaks up demand into 5 percent stacked groups, and shows the supply mix for each 5 percent group. CGS = Central Generation Stations; indp = independent generators

Source: KTPCL data

[21] The GTG and similar models can give results that suggest whether to build new coal plants or not if they find optimal operations showing a very low PLF for the coal plant–that would be unviable. On the other hand, this doesn't directly address the issue of should a new RE be built or not, especially when compared to already built or nearly finished coal capacity.

It's irrefutable that 2014 Karnataka RE output data as measured by the grid is different than what modeling projects are. This isn't to say the use of models per se is wrong, and these may be inevitable when better data are unavailable, but GTG and similar analyses must have a wider range of input data and more granular data.

3.4. Coal will not be as easy to flex

A key assumption is that coal plants will flex their output (especially downwards) and produce at a lower level than their design capacity. This impacts both the plant efficiency and creates wear and tear. The base case assumes all coal plants can go down to 55 percent output, as per CERC guidelines for Central plants (often matched by states per notifications), and also ramp at a particular rate.

There are costs for both ramping and start-stop operations. Let's leave aside debate within the industry on what such costs are. Can they even do so, technically? It turns out that this depends heavily on the vintage of the plant and its design. Newer ones can do so and were, in fact, asked to design for the same by the Central Electricity Authority (CEA). Older ones cannot, not without severe economic and operating penalties. As an example, Tamil Nadu's dozen older (210 MW) units reportedly need oil support if their output goes below 170 MW.[22] The norms for payments for lowering output are also reported to be insufficient, as disputed by Maharashtra utilities.[23] Flexing is a key topic for research and testing, and a key insight from the GTG study as being a major determinant of system operations. Hopefully, it's only a matter of investment, training, and effort that can make it happen. But solutions won't be uniform across India, varying by age, vintage, technology, etc. In fact, the GTG study uses central versus state units as demarcation for ability to flex, but reality likely won't be so simple.

Investments for enabling flexing are unlikely to be borne by RE, and thus thermal plants would treat such efforts as a compliance requirement and passed through to consumers. But based on NTPC's testing at their Dadri plant, this means coal plants would be paying many tens of crores per GW to reduce their output![24] There are indications that unless super-critical plants are designed for flexing, they have lower ability to flex down, lest they lose super-critical (efficient) operations. This prompts the challenge that the plants that may be asked to flex the most are the ones who have a high variable cost, and so flexing down with a penalised (worse) heat rate is a double whammy. Alternatively, if newer plants are the ones best

22 "Report of the Task Force on Integration of Electricity from Renewable Energy Sources in the Grid during the 12th Plan & Beyond", CEA August 2016

23 CERC's 2016 guidelines (No. L-1/18/2010-CERC) allowed for a flat percentage of heat rate (efficiency) reduction, plus oil support for start-stops beyond a certain number in a year. In response, a number of state utilities, e.g., in Maharasthra, have filed petitions with the state regulators over the ability or inability to meet the 55 percent flexing norms (see Case No. 15 of 2017, MERC).

24 NTPC's test was for Dadri-6, which is a newer unit; there are very limited data on flexing capabilities for older plants. The flip side of claims of limitations of older plants is how much is posturing or a negotiation stance?

able to flex down, they are anyways more efficient and thus the ones we do not want reducing output first. How low can coal's output go? Doing a crude back-of-the-envelope calculation, let us assume 55 percent flexing at a national level (some plants might do more, at a cost, but others certainly can't). If 2018 has about 200 GW of coal capacity, only about 120 GW is being used on any given day, so these need to be on so it can provide power in the evening (at the peak). If these plants need to operate at 55 percent output, that's about 65 GW of supply at a "met load" level that has to come from coal, likely some 70 GW by 2022. Add in nuclear power and we find a finite residual for RE. Note that any calculations for noon demand (lower than the peak daily demand) include stochasticity–periods of low demand mean some days of demand tens of GW lower than on high demand days. If we see generation output data from the government's MERIT portal, mid-day coal output often goes down below 90 GW output in August 2018, so using 65 GW as a minimum national coal output, that only leaves 25 GW of additional noon-time headroom for RE with today's demand, maybe rising a bit as demand grows to 35 GW by 2022 (assuming no major load curve shape change by then).

4. Suggestions for future studies on RE grid integration in India

RE variability and coal flexing are two of the key issues flagged, and we use these as starting points to suggest improvements for the next level of analysis and simulation for RE grid-integration. Clearly, the more the granularity the better, not just with time-scales, but geographically as well. Going below a national or regional analysis, state issues become important, including intra-state technical limitations (such as transmission), not to mention financial and contractual issues. This is a challenging task not just computationally but also due to data limitations. GTG has modeled key states at a sub-national level, but the locational details of capacity addition (especially RE), demand, and transmission means this is an exercise fraught with even more assumptions than national flows aggregated by state-to-state flows of power.

It goes without saying that most of the policy implications from the GTG study need analysis and a roadmap for implementation. These include operating larger balancing areas than the state and improving the flexibility of coal plants. Details of how these are to be done and at what cost are beyond the scope of this paper, and will require multiple stakeholders coming together. If making coal plants more flexible requires capital investments, we see a parallel challenge of finding funding for capital investments for making coal plants comply with upcoming emissions norms. RE's shadow is real, but in the short to medium term, India cannot escape coal, especially not during non-RE time periods and at locations near coal mines where the marginal cost of coal is very low.[25]

A future study must incorporate the economics of load dispatch, which inevitably becomes state-centric. GTG's state reports themselves list a number of ideas for future studies,[26] such as modifying load curves from 2014 based on expected shifts in consumer mix and behavior.

The GTG is a sophisticated analysis, but there are studies in India that have conflated energy (kWh) with capacity (kW) with a simple multiplier. However, even for a sophisticated analysis figuring out which (kW vs. kWh) to design the economics around is a challenging problem that isn't just about optimisation–it's

25 For more details on the economics of RE and coal, see Rahul Tongia and Samantha Gross (in press), "Working to turn ambition into reality: The politics and economics of India's turn to renewable power", Brookings Institution Paper (forthcoming).

26 See the Karnataka state report for a large list of improvements for future studies (https://www.nrel.gov/docs/fy18osti/70950.pdf)

a choice based on risk tolerance as well. Energy (supply options) can be designed for statistically, but capacity doesn't work that way. Getting energy wrong usually just means higher costs–getting capacity wrong can mean outages if not grid failure. Capacity requirements are often based on a reasonable expectation of "worst case" planning scenarios - and power grids are inherently designed conservatively. On the other hand, through learning, improved technology, and increased "smarts" in the grid (including flexible demand and energy storage), the level of conservatism required is also reducing.

A future analysis could start by comparing optimisation for 2014 per the same model and comparing it with what actually happened in 2014, attempting to answer how much is the real-world different from "best case". While there was extensive calibration for the same in the GTG analysis (detailed in the study's Appendix C), this focused extensively on load flows as visible to POSOCO; in-state details aren't easily available even now. Our limited examination of Karnataka data shows the GTG model and what happened aren't 100% aligned.

One could do a different calibration in two steps–first using similar wind/solar predicted outputs as per the models, and then also modeling the system using the actual RE in 2014, to the best extent data is available.[27] Both of these can be compared with what actually happened in 2014, in terms of which plants supplied power when. This exercise will give insights into the differences between theory and practice, and we can then examine specific operational, regulatory, and policy reasons for deviations from "optimal" that could be tweaked. While it is a stated norm, there isn't evidence to prove all states follow merit-order-dispatch all the time, especially when we consider the portfolio options Open Access (power markets) can offer.

Maybe there are factors that are difficult to model, such as how hydropower is dispatched to balance irrigation and water needs with power output. Even the decision to meet load or to load-shed isn't a purely economic one–political choices often guide such decisions. Even lack of fuel (or cooling water) impacts coal plants in the real world. It's unclear how one can optimise a model with such unknowns and uncertainties. One possibility is to create models that start with a "priced to perfection" base output on top of which we add layers of uncertainty and deflators or multipliers for deviations from perfection, which inherently raise costs.

The first step for improved future studies will be better data, not just on actual RE output with locational and Time of Day granularity but also on any curtailment, other demand, etc.[28,29] Improved data should

27 RE curtailed is ordinarily not reported, at least for most states, and rooftop RE data are also scarce. Even grid-scale RE feed - in is hard to know especially for smaller and medium scale feed-ins.

28 The Clean Energy Finance Forum (CEFF), a voluntary, multi-stakeholder body invited by Piyush Goyal, Minister for power and RE, provided a series of recommendations for financing RE in India. See "Home," India Clean Energy Finance Forum, http://ceff.strikingly.com/#documents-and-reports.

29 Details on how to disclose curtailment are given in Tongia (2018) "Embarrassment of riches? The rise of RE in India and steps to manage "surplus" electricity" available at https://www.brookings.edu/blog/planetpolicy/2018/06/15/embarrassment-of-riches-the-rise-of-re-in-india-and-steps-to-manage-surplus-electricity/

ideally extend to visibility onto LDC operations. LDCs (and government policies) have been asking RE generators to give day ahead schedules, with (yet to be enforced) notifications penalising generators for deviations greater than 30 percent. Improved forecasts are a must if the system is to be balanced at lowest cost. In addition, a more complete analysis would factor in contractual obligations for all the generators, to properly convey not just fixed versus marginal costs but take-or-pay obligations as well.

While "higher costs" of "higher RE" isn't always a focus of technical studies, this intersects when we consider stochasticity. Instead of deterministic models we should have stochastic models that include uncertainty (of RE output, real-world constraints such as plant outages, and demand), and these should link to risk tolerance or preferences. Loss of load probability (LOLP) studies should also link to implicit costs or negative values for load-shedding. This step will likely increase generation requirements (if states truly want to end load-shedding).

Note that we have focused on grid-scale RE. Integrating rooftop solar is a very different challenge both economically (especially for Discoms that lose paying customers) as well as technically; the low-voltage grid wasn't designed for feeding in solar power with bi-directional power flows. Out of 100 GW solar by 2022, 40 percent is slated for rooftop solar, and the rooftop solar quantum installed thus far is an order of magnitude lower than grid-scale installation and lags far behind the respective target (as of the end of 2017).[30] Many other regions including Germany and California have seen far higher uptake of rooftop solar, especially with innovative financing and support mechanisms. This segment could also grow dramatically in India at some point, after which it would show up not as supply but lower demand (from a grid perspective). One key difference is visibility into rooftop solar may be far more limited, especially if consumers have only net-metering capabilities instead of a separate gross solar meter. Depending on their consumption on-premises, different days we could have different inputs to the local grid. While in aggregate this should smoothen out, there can be strong local if not wider-area correlations in the variation of net feed-in power.

In the longer run, handling 175 GW of RE and subsequently more RE requires a stronger grid with improved signaling. Solutions such as time of day pricing (starting at the wholesale procurement level, before retail consumer time of day) will help incentivise improved supply options, including peakers, storage technologies, and load shifting including through smart grids (demand response). Electric vehicles can also synergise with RE, especially if the pricing signals are right. Of course, India needs a stronger and smarter grid regardless of higher RE, and not all the burden of grid improvements should be placed on the shoulders of RE.[31]

30 http://www.newindianexpress.com/business/2018/may/08/india-may-miss-rooftop-solar-target-1795315.html

31 Ashwin Gambhir, Jatin Sarode, and Shantanu Dixit,"Grid Integration of Renewables in India: An Analysis of Forecasting, Scheduling and Deviation Settlement Regulations for Renewables" 2016, Prayas Energy Group, available at http://prayaspune.org/peg/publications/item/327-grid-integration-of-renewables-in-india.html

Beyond just technical issues of handling high RE, India needs frameworks that provide signaling for the state of the grid, and what types of power are required when and where. This should ideally lead to feedback not just at an instantaneous procurement level, but when choosing which type of power plants to build. If the need is more peak power, then adding solar plants alone won't help, but neither will adding coal plants, which are designed for baseload operations and prohibitively expensive if only run for a few hours per day.

Any optimisation like via the GTG study is for after plants are built–it is a separate but much-needed exercise to figure out which type of plants to build, where, etc. While making coal flex is a major need, this requires investment. Perhaps the future can enable more alternatives, especially using this same quantum of funding for, say, procuring additional gas which can utilise existing but low-PLF gas plants, or for energy storage technologies, or demand response. The lowest-cost solution will not be a single technology, but a portfolio of solutions.

In this paper, we've used Karnataka data as it was best available to illustrate a point, and while data from a single state shouldn't determine the future, especially when we have larger balancing areas possible, there is a divergence between what is technically feasible versus what is economically feasible. Even with infinite and free transmission, are there takers outside the state for "surplus" power? Given demand and RE supply are comparatively similar especially for many neighboring states (e.g., wind in southern India is often relatively similar during the monsoon season), who will offer to consume (buy) energy during surplus (off-peak) periods, more so if they themselves are not deficient during those time periods? If one has sufficient generation capacity in-state and is paying fixed costs regardless, how does RE from another state compare to in-state alternative variable supply's marginal costs? If we continue to treat RE as must-run, but this obligation is only on the host state, this is not a scalable solution. If the policy choice is to socialise RE's costs, this has to be across India.

Until the grid is able to properly signal incremental impacts of different power (location, time, ramping, predictability, etc.), an interim solution may be to have RE-integration surcharges to help defray such costs. This should be a dynamic signal, not a surcharge, to align with grid conditions and also spur other complementary solutions such as peaking generators, storage, demand response, etc. Ultimately, the question of integrating RE isn't going to be "can we?" but rather "how best can we?"

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About the Impact Series

Brookings India's fundamental objective is to contribute meaningfully to the process of designing solutions for India's policy problems. We aspire to do this in a way which fully reflects the core values of analytical quality and independence of views. We believe that policy recommendations based on these two attributes are most likely to have a positive impact on outcomes.

Since we began our activities in 2013, we have been active in three broad domains: Economic Development, Foreign Policy, and Energy & Sustainability. We have initiated research on several issues within these domains and, simultaneously, organised a regular series of conversations between various stakeholders, who bring their particular perspective to the discussions in a constructive way. These activities have helped us to understand the nature of specific problems in each domain, gauge the priority of the problem in terms of India's broad development and security agenda and develop a network of people who think deeply about these issues.

In this series of policy papers, the authors offer concrete recommendations for action on a variety of policy issues, emerging from succinct problem statements and diagnoses. We believe that these papers will both add value to process of policy formulation and to the broader public debate amongst stakeholders, as opinion converges on practical and effective solutions.

Many of the papers are written by Brookings India researchers, but, in keeping with our objective of developing and sustaining a collaborative network, we have invited a few experts from outside the institution to contribute to the series as well.

We look forward to active engagement with readers on the diagnoses and recommendations that these papers offer. Feedback can be sent directly to the authors.

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