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Thomas Spencer, Neshwin Rodrigues, Raghav Pachouri, and Shubham Thakre

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

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ABSTRACT

While recent wind and solar auctions have delivered some of the lowest electricity prices in the Indian power system, the inherently variable nature of solar and wind resources pose challenges in supplying reliable electricity. The difficulty in the real-time balancing of supply and demand only increases with an increasing share of wind and solar in the generation mix, requiring attention to not just the operational and technical challenges, but also to the costs of power system adaptation. The need for an analysis of the costs of integration in the Indian context has gained further urgency in the post-COVID scenario, which has seen deterioration in the already precarious finances of power distribution companies. In this paper, we use an hourly power system model, which co-optimizes both power system asset dispatch and investment in new assets, in order to explore the drivers of grid integration costs of VRE, and the impact of different assumptions on their magnitude, inflection points, and boundary conditions. Four scenario 'families' were developed, which vary assumptions of a number of factors, including demand, RE deployment, cost of capital, retirement of end-of-life assets, storage costs, availability of market purchases, and capacity addition options in conventional generators. The scenarios are designed to assess the grid integration costs that are likely to be the most substantial in the Indian context.

Key conclusions which emerge from the analysis are:

1. Given technology costs foreseeable for the coming decade, the short-term optimal VRE level is substantially higher than VRE shares present today

2. Optimal VRE penetration is determined by the trade-off between variable cost savings and per unit increases in fixed cost, and this arbitrage will vary as a function of both geography and policy decisions taken.

3. The analysis in this paper suggests that within the Indian system, demand growth and the opportunities for variable cost arbitrage in the coming decade can already enable VRE shares of 40%, even accounting for the impact on the sunk costs of the existing system. As demand continues to grow after 2030, and the energy costs of storage fall below the threshold identified in this study, VRE is expected to essentially meet subsequent incremental demand growth.

4. The low cost of cheap VRE makes it preferred for whatever parts of their load curve it can serve, and as its share increases, VRE begins to determine the economics of the rest of the power system. Its increasing share in the generation mix is accompanied by an increased frequency of balancing requirements, making Li-battery storage systems more economical, and new coal less.

5. The most cost-effective way of minimizing the sunk costs of seasonal balancing options is by enhancing the grid integration of the Indian system, allowing complementarities between demand and supply across states and regions to supply this seasonal balancing. While brownfield pumped hydro and potentially some gas capacity may additionally be required, additional coal appears economically unviable.

6. VRE is unlikely to cross thresholds at which it would drive substantially higher system costs in the short term, increasing the importance of focusing on minimizing and allocating gross costs in the system, and maximizing gross benefits.

1. Introduction

Recent wind and solar auctions have delivered some the lowest electricity prices in the Indian power system. At the same time, the wind does neither always blow nor the sun always shine. The challenge balancing the demand and supply of the power system in real time therefore increases with increasing shares of wind and solar in the generation mix. There are a number of studies detailing the operational and technical requirements for India to integrate higher shares of VRE (Palchak et al., 2017; Spencer et al., 2020).

However, less attention has been paid to the costs of adapting the power system to higher shares of VRE – so called grid integration costs. This topic has gained in salience with the COVID-19 shock, which has further strained the finances of India's troubled electricity distribution (DISCOM) sector. In addition, India's economy and electricity sector have taken a substantial hit, with the outlook for electricity demand clouded by substantial uncertainty (Spencer, 2020). Concerns have been raised about the persistent low capacity utilization factor (CUF) of the existing coal fleet and the associated fixed cost liability that is borne by DISCOMs.

In this context, this paper aims to provide a techno-economic analysis on the basis of detailed hourly electricity sector model, of certain crucial aspects of grid integration costs. The paper introduces grid integration costs and VRE-specific factors as well as a description of the model which has been used in the study. Using data from MSEDCL to understand the drivers of VRE integration costs, it then moves on to explore the four scenario families which form the focus of the paper, investigating the impact of different assumptions, and the key takeaways which the models provide.

2. What Are Grid Integration Costs?

The concept of grid integration costs of VRE is complex and belies simple explanation. Nonetheless, this section aims to set out as briefly and simply as possible an understanding of grid integration costs. These are generally understood to be broken down into three categories: transmission, balancing, and profile costs. For each of these three aspects of grid integration cost there is an associated inherent characteristic of VRE which drives the cost. We, therefore, discuss these below as three distinct 'VRE characteristic–system cost' pairs (Hirth, 2013):

1. Renewables **spatially diffuse and often not located near load centres,** and they therefore create **transmission costs**. Wind and solar resources are often located far from load centres and require extensive transmission infrastructure to evacuate power towards load centres. The cost of this transmission infrastructure must be borne by the power system. However, it is important to note that all generation assets create transmission costs. For example, India's coal resources are concentrated in less economically developed Eastern States. Coal and electricity must therefore be evacuated to load centres. The transmission cost of India's coal-based power system is substantial. However, because of the lower CUF of VRE, and its high spatial diffusion,[1] it is understood that VRE may have higher transmission costs than alternative technologies.

[1] In technical terms, VRE have a low power density (W/m^2) and therefore need larger areas to gather the same power than more power dense technologies. The transmission cost of gathering VRE from large areas is likely to be higher than a more power dense technology.

2. Renewables generation **cannot be perfectly forecast in the short-term**, and therefore requires assets to **balance** the short-term variations in supply that arise from forecast error. This balancing cost arises from the cost of reserving these assets, *in case the forecast generation from VRE turns out to be wrong*, as well as the generation cost of these assets when they are used. It is important to note that forecast error is not specific to renewables. DISCOMs can make errors in forecasting their day-ahead demand, transmission infrastructure can break down unexpectedly, conventional generators can experience unexpected outages, etc. The cost of holding enough assets for such contingencies, as well as the cost of activating them in the case the contingency eventuates, is known as the balancing cost. Although all technologies bring balancing costs, the short-term stochastic nature of VRE brings particular challenges to its balancing costs.

3. VRE output is **non-dispatchable and not perfectly correlated with load**, and therefore **other power system assets need to be available** to supply load for hours when VRE is not available. This would be the case, *even if VRE were perfectly forecast.* This generates so-called 'profile costs'. These can be divided into two aspects. Firstly, because these back-up assets are only required to generate at times when VRE is not available, the CUF of these assets is correspondingly lower, and the per unit fixed costs of these back-up assets are higher. This is the fixed cost aspect of profile costs. Secondly, if these back-up assets are required to operate at part load, or with frequent starts and stops, then the heat-rate degradation and start-up costs of variable operation will raise the per unit variable costs. This is the variable cost component of profile costs.

With this brief discussion of the three different aspects of the grid integration costs of VRE, we now turn to the description of the model that we use to investigate VRE integration costs.

3. Model Description

In this study, we use a detailed, hourly power system model which co-optimizes both power system asset dispatch and investment in new assets. The model is based on the open-source framework 'Python for Power Systems Analysis' (PyPSA), a well-established open-source power system model (Brown et al., 2017) variable renewable generation, storage units, coupling to other energy sectors, and mixed alternating and direct current networks. It is designed to be easily extensible and to scale well with large networks and long time series. In this paper the basic functionality of PyPSA is described, including the formulation of the full power flow equations and the multi-period optimization of operation and investment with linear power flow equations. PyPSA is positioned in the existing free software landscape as a bridge between traditional power flow analysis tools for steady-state analysis and full multi-period energy system models. The functionality is demonstrated on two open datasets of the transmission system in Germany (based on SciGRID). PyPSA can perform optimal power system dispatch, capacity expansion, and network load flow. To execute the model, we use a high-performance computer, and a commercial solver (Gurobi). For every scenario described in this study, we operate the model at 8760-hour resolution, i.e. for every hour of the calendar year. In any model, certain simplifications need to be made in order to keep the model problem tractable. Typically, this involves trade-offs on one or more of the following axes: temporal, spatial, and technical detail. We make our trade-off on the spatial and technical axes. Regarding spatial detail, we represent our model boundary (see below) as a single node, without transmission infrastructure. Regarding technical detail, we do not represent the unit commitment problem, a choice that is likely to somewhat favour VRE in the model.

In order to keep the model system tractable and limit the computational resources required, we model a single DISCOM service area. This also allows us to keep the model problem concrete, and draw on real-world data to develop the model system. We select MSEDCL as our case study, **although we note that this study is intended as a theoretical exploration of the drivers of VRE integration costs, not as a detailed study of the DISCOM *per se*.** The paper is intended to provide a template of how a study of integrated resource planning should be undertaken. The following points detail the key data inputs into the model (specific details about numerical assumptions are given in the following section on scenario design):

» *Demand:* We take the 2019 hourly demand profile, and multiply it by a demand multiplier consistent with demand growth to ca. 2025–2030. This means that we do not assume any load-profile change, although in reality there will inevitably be endogenous and policy-driven changes in the demand profile (e.g. agriculture pump shifting).

» *Supply:* We take details of all the PPAs signed by the DISCOM and input them as generators in the model, with fixed and variable costs consistent with the PPA documentation (MSEDCL, 2021). In addition, we give the model the option of investing in new wind, new solar, new gas, new coal, and new hydro. Finally, we also give the model the option of dispatching power from the power market. This is modelled as a dispatchable generator with zero fixed costs, and marginal costs set at a level consistent with recent market prices. The amount if dispatchable power is capped, as per the scenario described in the following section.

» *Storage:* We give the model the option of investing in two storage technologies: li-ion battery electric storage (BES) and brownfield pumped hydro. By brownfield, we mean an expansion of existing reservoir hydro to give it a pumping capability.

The objective function of the model is to meet demand in every hour of the year, while minimizing total system costs. System costs consist of three components:

» The fixed costs of existing assets (i.e. fixed costs of existing PPAs).

» The fixed costs of new-build assets.

» The variable costs of all dispatched assets.[2]

The representation of existing PPAs allows us to accurately represent the 'sunk cost' of existing assets, whose per unit cost rises inversely to CUF (for example, as higher VRE reduces the CUF of existing assets). **This allows us to capture the 'profile costs' of rising VRE shares on the per unit fixed costs of both new and existing assets.**

4. Scenario Design

In this study, we take an exploratory approach to scenario design, and not predictive or prescriptive approaches. This means we are aiming to investigate the drivers of grid integration costs of VRE, their magnitude under different assumptions, inflection points, and their boundary conditions. As a consequence, we take assumptions that are unlikely to be 'realistic' within the study period (2025–30), but which allow us to shed useful light on the question of the grid integration costs of VRE. We operate within a framework of 'scenario families' and 'scenarios':

[2] As noted above, these variable costs exclude heat rate degradation or from start-up and shut-down costs.

» *Scenario families:* Groups of scenarios designed to explore specific aspects of the research question.

» *Scenarios:* Individual scenarios within each scenario family, for which the simulation is conducted for the full 8760 hours.

We develop four scenario families, each of which has 8–14 scenarios within it:

1. *Multivariate:* We vary assumptions on demand, RE development, cost of capital, retirement of end-of-life assets, availability of market purchases and availability of capacity addition options in conventional generators. A detailed table of assumptions under this scenario family is given in the following section.

2. *RE Penetration:* We exogenously fix the amount of new wind and solar, increasing linearly from 0 GW of new wind and solar, to 25 GW of new wind and 15 GW of new solar. All other input assumptions are fixed as per the baseline settings.

3. *Solar Penetration:* We exogenously fix the amount of new solar, increasing linearly from 0 to 40 GW. New wind is set at zero. All other input assumptions are fixed as per the baseline settings.

4. *Storage Cost:* We exogenously fix the capital cost of the energy component of storage, beginning at 200 USD/kWh (i.e. above today's level) and decreasing linearly to a theoretical minimum of 20 USD/kWh. The model decides on optimal RE build out. All other assumptions are fixed as per their baseline settings.

5. Numerical Assumptions in the Multivariate Scenario Family

5.1 Scenario Framework

Table 1 shows the scenario variables for the multivariate scenario family. For each of the 13 scenarios within this family, assumptions are varied across the aspects of demand, VRE build out, retirement of end-of-life assets, discount rate (weighted average cost of capital), extent of purchases from the market, BES storage costs, and deployment of pumped hydro. The following points detail the assumptions taken across each of these aspects:

» *Demand:* In the baseline demand scenario, demand is assumed to grow by a factor 1.37 on 2019; in the low demand scenario by 1.27; and in the high demand scenario by 1.47. The profile remains as per 2019. In the baseline, peak demand reaches 27.5 GW, and energy requirement reaches 186 TWh, and proportionally higher and lower in the high demand and low demand scenarios, respectively.

» *VRE:* In the baseline RE build out scenario, RE build out occurs endogenously as per the model optimum; in the high scenario exogenous multipliers force wind and solar buildout above the baseline optimum (respectively 1.25 for wind and 2.0 for solar); and likewise but inversely in the low scenario (respectively 0.4 for wind and 0.5 for solar).

» *Retirement:* If end-of-life retirement is TRUE, existing assets that reach the end of their technical life by the simulation year are assumed to retire before the simulation. In reverse, if FALSE, these assets remain online and available for generation.

» *Discount Rate:* This refers to the discount rate, which is used to calculate the fixed cost annuity for both the existing assets (PPA cost), and new build assets. It varies between 11% in the baseline setting, and 12% and 10% in the high and low settings, respectively.

» *Market:* This refers to the maximum quantum of power that can be purchased from the market in any one hourly timestamp. In the baseline setting this is set at 2000 MW* demand growth (2740 MW); in the high setting three times this volume can be purchased in any one timestamp.

» *Storage cost:* In the baseline scenario the energy cost of BES storage is set at 110 USD/kWh. In the low scenario, this is reduced to 80 USD/kWh.

Table 1: Scenario Variables in the Multivariate Scenario Family

Scenario Name	Demand	VRE	Retirement	Discount Rate	Market	Storage Cost	Pumped Hydro	Gas Price
Baseline	Baseline	Baseline	FALSE	0.11	Baseline	Baseline	Baseline	Baseline
Retirement	Baseline	Baseline	TRUE	0.11	Baseline	Baseline	Baseline	Baseline
High_RE	Baseline	High	FALSE	0.11	Baseline	Baseline	Baseline	Baseline
Low_RE	Baseline	Low	FALSE	0.11	Baseline	Baseline	Baseline	Baseline
Low_ Demand	Low	Baseline	FALSE	0.11	Baseline	Baseline	Baseline	Baseline
High_ Demand	High	Baseline	FALSE	0.11	Baseline	Baseline	Baseline	Baseline
Low_ Discount_ Rate	Baseline	Baseline	FALSE	0.10	Baseline	Baseline	Baseline	Baseline
High_ Discount_ Rate	Baseline	Baseline	FALSE	0.12	Baseline	Baseline	Baseline	Baseline
High_ Market_ Purchase	Baseline	Baseline	FALSE	0.11	High	Baseline	Baseline	Baseline
Low_ Storage_ Cost	Baseline	Baseline	FALSE	0.11	Baseline	Low	Baseline	Baseline
No_New_ Gas	Baseline	Baseline	FALSE	0.11	Baseline	Baseline	Baseline	Baseline
High_Gas_ Cost	Baseline	Baseline	FALSE	0.11	Baseline	Baseline	Baseline	High
Pumped_ Hydro	Baseline	Baseline	FALSE	0.11	Baseline	Baseline	High	Baseline

Source: authors

» *Pumped Hydro:* In the baseline scenario, total available brownfield pumped hydro capacity is capped at 1000 MW. In the high scenario, this cap is removed and the model is left to invest in whatever is optimal.

» *Gas Price:* In the baseline scenario, the marginal cost of new gas is 3.5 Rs/kWh. In the high scenario, this increases to 4 Rs/kWh.

5.2 Technology Cost Assumptions

Table 2 shows the baseline cost assumptions for the investment options available to the model. Several observations are required with respect to the expression of investment costs for BES and pumped hydro storage. For conventional technologies, the capacity cost represents the investment cost of building 1 MW of that technology, while the energy cost represents the marginal cost of generating 1 kWh from that technology (i.e. fuel costs for conventional technologies, nil for zero marginal cost technologies). However, in the case of BES and pumped hydro, these concepts are somewhat different:

» *BES:* Capacity cost represents the investment cost of expanding the power component of the facility by 1 MW (i.e. largely the inverter, balancing of systems, etc.). On the other hand, the energy cost *is not a marginal cost:* it is the investment cost of expanding the BES facility by one kWh, i.e. the cost of the battery pack itself. With these two investment cost inputs, the model is completely free to co-optimize the power and energy components of the BES facility, with their ratio of the build out of energy and power components representing the storage duration at maximum power output.

» *Pumped Hydro:* As with conventional generating technologies, the capacity cost is the cost of expanding the brownfield pumped hydro facility by 1 MW. Instead of assuming a separate investment cost for fixing the energy rating of the facility, we assume a fixed maximum storage duration of 12 hours at maximum power output. In other words, if the model builds 1000 MW of brownfield pumped hydro, the maximum energy rating of the facility is 12,000 MWh. Thus, the model cannot co-optimize the power and energy components of the pumped hydro facility, and the cost of expanding the energy component of the facility (to a maximum energy/power ratio of 12) is assumed to be subsumed within the capacity cost.

Table 2: Baseline Technology Cost Assumptions

Technology	Capacity Cost (Rs Cr/MW)	Energy Cost (Rs/kWh)	Must-Run CUF Before Curtailment (%)
New Coal	7.0	2.28	n/a
New Gas	4.5	3.5	n/a
New Solar	3.3	0	26%
New Wind	4.0	0	29%
New Reservoir Hydro	14.5	0	n/a
BES*	1.19	7700	n/a
Pumped Hydro^	3.5	0	n/a

*Source authors: *As noted above, the energy cost of BES is not a marginal cost, but rather the investment cost of expanding the BES facility by 1 kWh.^The capacity cost of pumped hydro assumes an energy/power ratio of 12.*

6. What Grid Integration Costs Do We Assess?

Based on the above description of the model set-up and scenario architecture, it is now possible to detail which grid integration costs we assess concretely:

» *Network costs:* Because we operate the model as a single node, with no intrastate or interstate transmission network, we do not assess network costs.

» *Balancing costs:* We do not explicitly assess balancing costs nor their allocation to demand or different generators. However, we do derate dispatchable capacities, thus building in a substantial reserve margin to the system (i.e. we assume an 85% availability factor for dispatchable generators). The fixed cost of this reserve margin is therefore inherent in the system-wide fixed costs that the model calculates.

» *Profile costs:*

- *Variable cost component:* we do not explicitly assess the cost of heat-rate degradation or start-up and shut-down costs.
- *Fixed cost component*: we explicitly assess the increase in fixed costs of all residual assets, existing and new-build, that arises from driving up the share of VRE (which drives down the CUF of the residual assets in the system).

We therefore primarily assess the fixed cost aspect of profile costs. We chose to do so because it is generally understood that profile costs are likely to be the largest grid integration cost of VRE, particularly in a system with large amounts of relatively young, capital intensive coal (i.e. high sunk costs in the system). **The results thus need to be interpreted with this in mind: they are not a comprehensive assessment of all relevant fixed costs, but rather a focused assessment of that aspect of grid integration costs that are likely to be the most substantial in the Indian context.**

7. Results

7.1 Multivariate Scenario Family

7.1.1 Headline Results

In this section we present the central results of the multivariate scenario family (see Table 1). Figure 1 displays the headline results in terms of levelized system costs and VRE share in total generation (Panel A), and capacity build out (Panel B). We start with some general observations, before moving to discuss in more detail the differences between scenarios.

Firstly, total VRE share is substantially higher than implied by a scenario of no new wind and solar build out. In other words, the model finds it optimal to build substantial additional VRE capacities. The Baseline optimal level of VRE is 41% of total generation, and reaches as high as 58% in the High_RE scenario (where VRE is promoted) and 22% in the Low_RE scenario (where VRE is constrained). Secondly, despite the very different levels of VRE build out, total levelized system costs – consisting of the fixed costs of existing and new-build assets, and the marginal costs of all dispatched assets – are situated within a relatively tight band compared to the Baseline scenario. In the High_RE scenario, total system costs are 3.6% above the Baseline level. In the Low_RE scenario total system costs are 2.2% *above* the Baseline level, indicating that restricting the build-out of new RE actually increases system cost (there is more discussion of the mechanism by which it does so in the following sections). The lowest cost is achieved in the High_Market_Purchase scenario, in which high purchases from the all-India market allow the model to avoid the investment in expensive new generating capacities. Here, total system costs are 3.8% below the Baseline level. Lower costs also occur when storage costs are low or substantial storage capacities are available (respectively the Low_Storage_Cost scenario and Pumped_Hydro scenario).

Regarding capacity deployment, the model selects substantial new capacities of both solar and wind as part of the optimal solution (13.3 and 14.4 GW respectively). In most scenarios, the model does build out some new gas generating capacity (2.1 GW in the Baseline) and exploits the full available potential for pumped hydro (1 GW). Only where gas deployment is constrained (No_New_Gas scenario) does the model select some new coal (710 MW), or where the low deployment of VRE raises the CUF of new build conventional generators (Low_RE scenario).

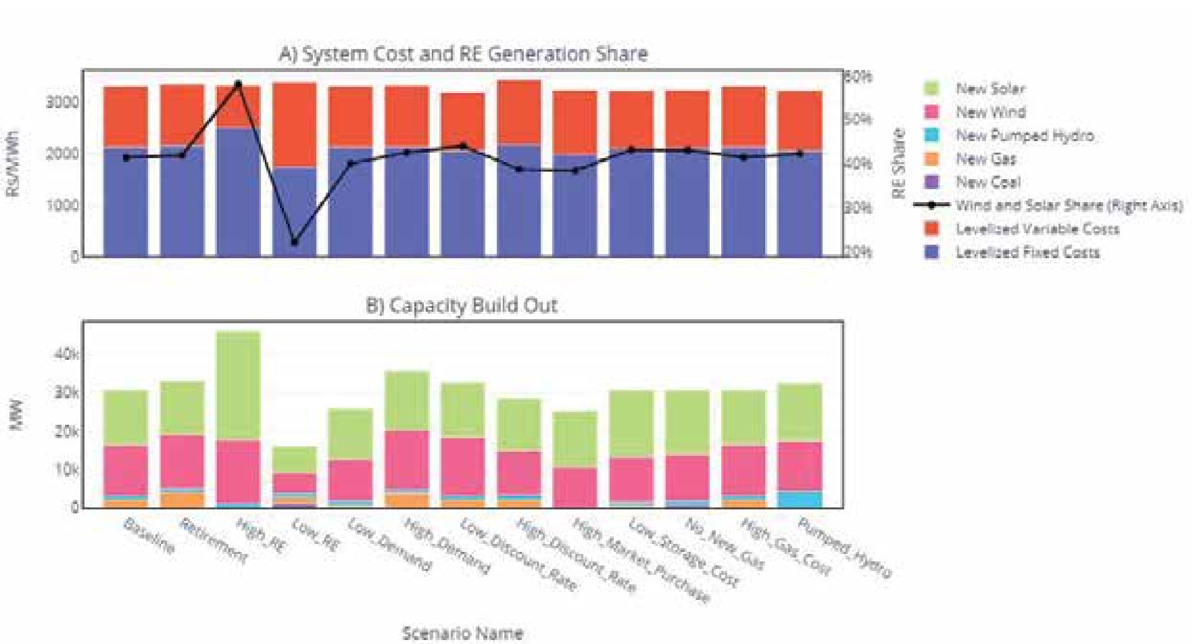

Figure 1: System Costs, VRE Share and Capacity Build-Out, Multivariate Scenario Family

Source: authors

Having made these general observations, we now discuss the impact of several individual assumptions in more detail:

» *Demand:* In the Low_Demand scenario, optimal VRE is slightly below the Baseline value, while in the High_Demand scenario it is slightly above it (40% and 43% respectively, relative to 41% in the Baseline). This is interesting from two perspectives. Firstly, the model is not just using VRE to meet incremental demand; in the Low_Demand scenario, the model actively reduces the CUF of thermal generation (despite incurring the increased per unit fixed costs thereof) in order to raise the share of VRE. Secondly, the model does prefer VRE to meet incremental demand: the higher the incremental demand growth, the higher the optimal level of VRE.

» *Retirement:* In the scenario with retirement of end-of-life assets, optimal VRE is slightly above the Baseline scenario (42% versus 41%), while total system costs are slightly higher (by 1%). This is because the model needs to build additional high fixed cost dispatchable capacities (in this case gas) to compensate the loss of retired assets, and to meet the parts of net load that both VRE and storage cannot serve economically (more discussion on this is given below).

» *Discount rate:* The model is highly sensitive to assumptions around the discount rate. In the High_Discount_Rate, optimal RE falls by 2 percentage points relative to the Baseline, while it rises by 3 percentage points in the Low_Discount_Rate scenario. This is because the discount rate directly influences the relative economics of fixed and variable cost technologies.

» *Market purchases:* Having more power available to purchase from the all-India power exchange is found to lower the system cost (by 3.8%), because no new high fixed cost assets are required to be built. Paradoxically, it also somewhat lowers the optimal level of VRE, despite the fact that market purchases are modelled as a perfectly flexible generator. The reason for this is that more market purchases somewhat reduce the opportunity for arbitrage between higher marginal cost generators and new zero-cost VRE.[3]

» *Storage Cost and Availability:* The Low_Storage_Cost scenario allows the model to increase the share of VRE by 2 percentage points relative to the Baseline, while lowering system costs by 0.4%. On the other hand, removing the restrictions on brownfield pumped hydro allows brownfield pumped hydro to substitute for all capacity addition in new gas, as well as slightly raising the optimal level of VRE (to 42%) and lowering total system costs (by 1.2%).

» *High Gas Costs:* High gas costs for new-build gas marginally raise the total system cost (by 0.01%) and does not affect the 'optimal' level of VRE. Nor does it have any impact on the optimal build out of new gas (2.1 GW in both the Baseline and the High_Gas_Cost scenarios). This demonstrates that new gas is being selected on the basis of its low capacity cost, and not on the basis of its energy cost.

7.1.2 BES Deployment

Figure 2 shows the deployment of BES in the multivariate scenario family, in terms of the rated energy capacity of the optimal facilities (Panel A), rated power (Panel B), and rated energy to power ratio (Panel C). Results can generally be classified into two groups depending on the level of storage built by the model. In the first group (which includes the Baseline scenario), the model finds it optimal to build about 1150 MW of BES power capacity and about 2900 MWh of BES energy capacity, for a storage duration at maximum output of ~2.5 hours. In the second group, the model suddenly finds it optimal to substantially

[3] This result needs to be interpreted with some care. As noted above, the model does not include the unit commitment problem. In a model with unit commitment, the technical challenge of VRE integration would be proportionally higher, and therefore access to large amounts of flexible market purchases would raise the amount of VRE that could be integrated from a technical perspective.

increase the optimal level of storage to as much as 3000 MW/16,500 MWh for a storage duration of up to 5 hours. This occurs in the High_RE scenario, where the model invests in further storage to complement the massive ramp up in solar capacities and avoid the curtailment thereof. Likewise, in the Low_Storage_Cost scenario (where storage energy costs fall from 110 USD/kWh to 80 USD/kWh), the model now finds it optimal to add further storage capacities and further solar capacities, driven solely by the lower cost of storage. In the No_New_Gas, the model partially makes up for the inability to invest in new gas by investing in additional storage, although this is not enough to stop the model from finding it necessary to also invest in 710 MW of new coal.

This raises the question of why the model invests in new gas and new coal? What determines the economics of these choices? This is the subject to which we now turn.

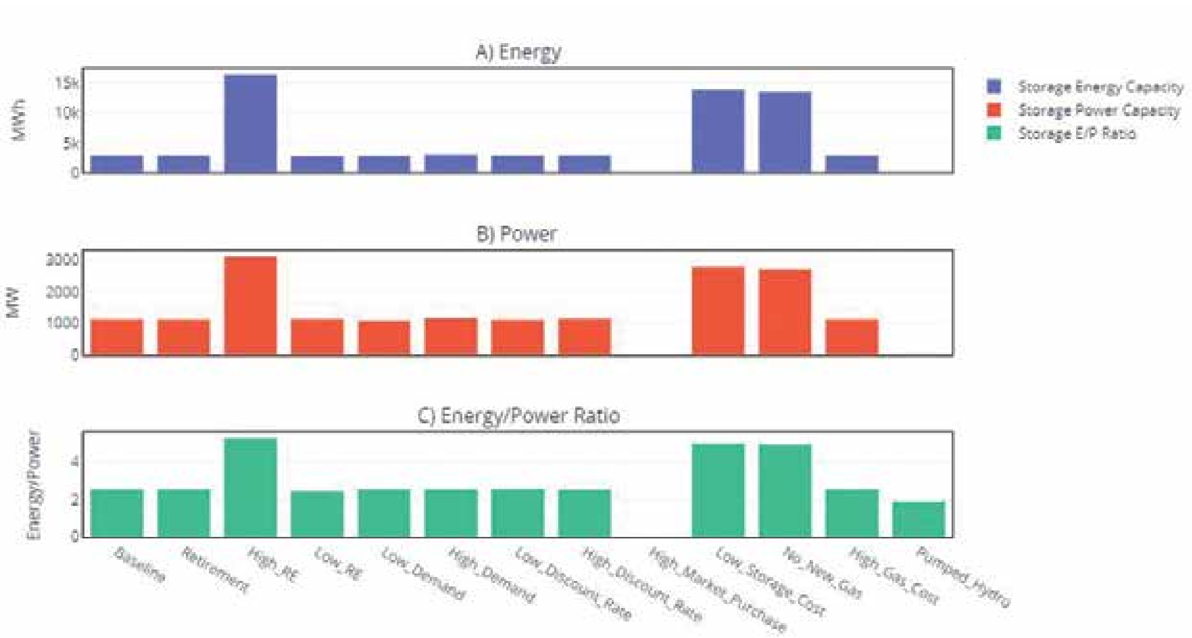

Figure 2: Storage Deployment in Terms of Energy, Power and Storage Duration

Source: authors

7.1.3 Economics of BES, Pumped Hydro and New Gas and Coal

Figure 3 unpicks a little more this question of the relative economics and system role of new gas, coal, BES and pumped hydro. Panel A shows the levelized per unit cost of energy based on actual dispatch (y-axis, log scale) versus the CUF (x-axis) for new gas, new coal, brownfield pumped hydro, and BES. CUF is calculated on the basis of nominal power built by the model for each technology, with the numerator being actual dispatch of each technology. We present this indicator for each of the scenarios in the multivariate scenario family for each technology. Where less than 13 data points are present, the technology was not built in each scenario; this is the case, for example, for new coal, which was only built in two scenarios. Panels B and C show the generation duration curve (i.e. output, non-chronologically sorted) as a percent of rated power capacity for new gas and BES, respectively.

Several aspects are worthy of note, helping to shed light on the economics and system role of each technology:

- *New coal:* New coal is only economic when the CUF of new coal is >55%, because of its higher fixed costs. This can only be achieved if the model restricts dispatch from other technologies. In the No_New_Gas scenario, the PLF of the existing gas fleet is substantially lowered to make room for coal addition, while the addition of extra BES and extra solar allow substitute for the addition of new gas. In the Low_RE scenario, lower VRE build out allows more of the net load curve to be available for coal generation, allowing high CUF new coal to become economical.
- *New gas:* New gas always operates at low CUF, regardless of the scenario. This makes its per unit levelized costs extremely high (in two scenarios, above 100 Rs/kWh). This shows that gas is essentially playing the role of seasonal peaker (see Panel B), operating at very low annual CUF. Here the lower capital costs relative to coal give it the advantage, despite its higher energy costs.
- *Pumped hydro:* Pumped hydro operates at nominal CUFs of 4–10%. This is also because seasonal constraints on charging due to low upstream water flow preclude fast charging of the energy capacity of pumped hydro through much of the year, and therefore the energy capacity is reserved for more infrequent discharging. This forces the pumped hydro to operate more as a seasonal peaker. This is evident also where its capacity is unconstrained in the Pumped_Hydro scenario, allowing pumped hydro to substitute for natural gas entirely in the peaker role.
- *BES:* The levelized cost of BES is relatively low between (2.1 and 4.4 Rs/kWh), while its power CUF is relatively high (between 20% and 26%). Because storage must charge in order to discharge, and does so at an energy penalty, achieving 20–26% CUF requires almost daily cycling. Here we

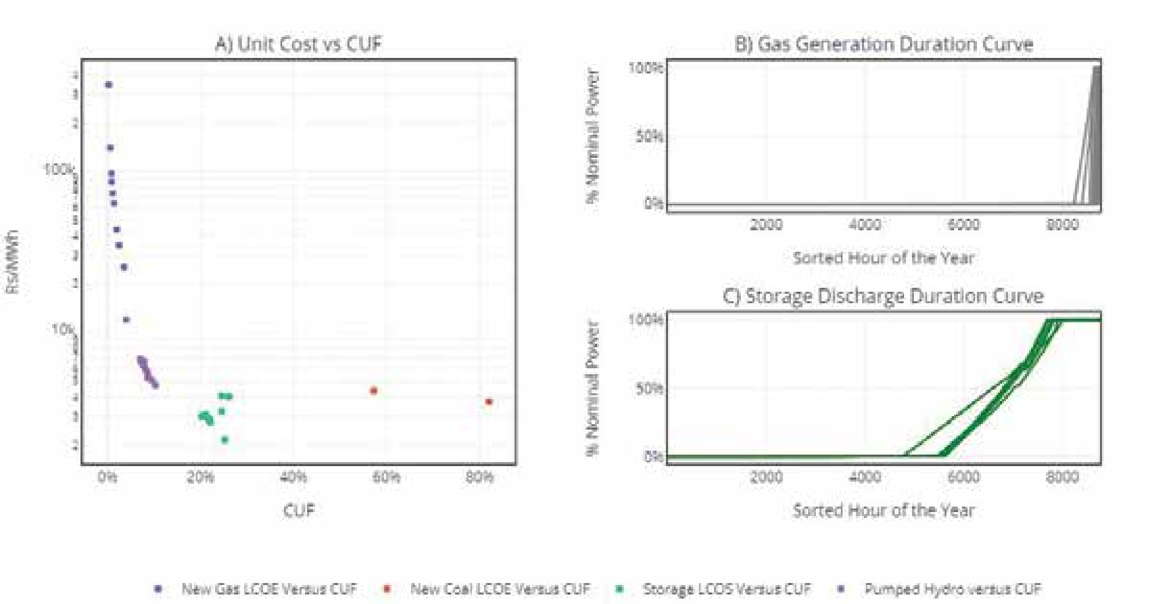

Figure 3: Unit Costs of New Gas, Coal, BES and Pumped Hydro Versus CUF

Source: authors

can see an important aspect of the economics of BES: the high sunk costs of BES require high annual cycling to allow a low delivered cost of energy. This therefore requires that storage serves parts of the net load curve which have a higher frequency than the parts served by new gas or pumped hydro. In other words, the high sunk costs of storage on both the power and energy side limit its role to daily balancing, leaving weekly or monthly balancing to other technologies (gas or pumped hydro).

7.1.4 Understanding the Arbitrage Between Gas and BES

In this section, we delve a little further into the arbitrage between gas and BES in the model. If gas has a levelized cost of energy (LCOE) which is much higher than that of BES (see Figure 3), why does the model not just build more BES in order to substitute for more expensive gas? Recall that unlike pumped hydro, the power capacity and energy capacity of storage are unconstrained in the model, and therefore as much of either can be built as the model deems cost-optimal. In order to investigate this question of the arbitrage between gas and BES, we break down the levelized cost of energy of both gas and BES into its power and energy components (Figure 4, Panel A). These concepts are defined as follows:

» *Power component of LCOE:* For conventional generators, this refers to the capacity cost of expanding the generator by 1 MW, multiplied by the nominal power of the generator, and levelized by the actual dispatch from the generator. Because the levelization occurs on the basis of actual dispatch, the numerator of this value is an energy unit (MWh). For BES, this refers to the capacity cost of the BES system related to expanding the BES by 1 MW (largely the inverter, balance of system (BOS), etc), multiplied by the nominal power of the BES system, and levelized by the

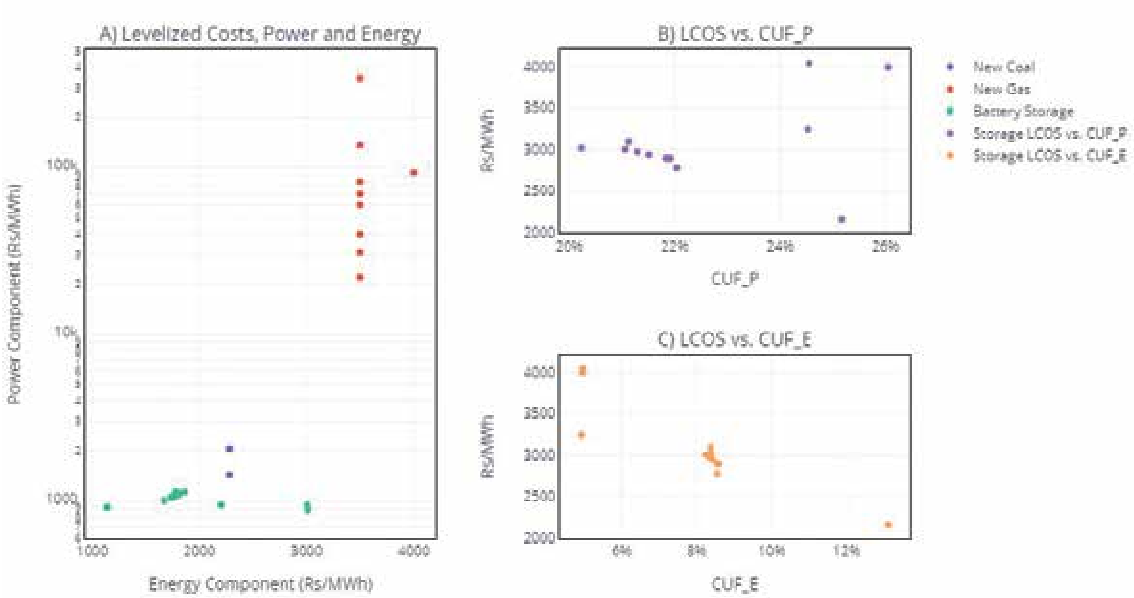

Figure 4: Levelized Cost of Energy from BES and New Gas, Broken into Power and Energy Components

Source: authors

actual dispatch of the system. For both BES and conventional generators, the power component is influenced by the CUF of the unit, because the power component of unit costs is a sunk cost and the CUF determines the amount of energy production by which the capacity cost is levelized.

» *Energy component of LCOE:* For conventional generators, this refers to the marginal cost of the generator, determined by the fuel cost and generator efficiency. *For conventional generators, this is a marginal cost and does not vary with CUF.*[4] This is why the data for New Gas in Figure 4, Panel A does not move on the x-axis, except in the High_Gas scenario where the marginal cost of gas increases from 3.5 Rs/kWh to 4 Rs/kWh. On the other hand, for BES the energy component of LCOE *is a sunk cost:* it represents the investment cost of expanding the BES unit by 1 MWh, multiplied by the energy rating of the facility, and levelized by the actual dispatch from the BES facility. This is why the energy component of the BES levelized cost of energy moves substantially along the x-axis in Figure 4, Panel A, depending on the utilization rate of the BES facilities.

These two concepts of the energy and power component of LCOE enable us to understand the arbitrage that the model is taking between new gas and BES. Because the energy component of storage LCOE is a sunk cost and is hence sensitive to CUF, the model builds as much storage as it can, but stops *when the utilization factor of the BES facility would drop so low as to render the levelized energy cost higher than that of new build gas.* At that point, the model finds it cheaper to build new gas facilities, even if the CUF of the gas facility is very low. The economic characteristics of gas determine this choice: its low capacity cost means that sunk costs are low, while its energy cost is a marginal cost not a sunk cost, and therefore does not increase with decreasing CUF.[5] The fact that the energy component of BES is a sunk cost, and not a marginal cost, means that its levelized cost is sensitive to utilization. There comes a point where the unserved part of the net load curve is too infrequent and of too long a duration (necessitating the build out of more sunk cost energy capacity from the BES) for it to be economically addressed by BES. It is this dynamic that drives the model preference for gas, even at high per unit costs, for the last 5–10% of the net load curve. It is the sunk cost nature of BES and the high energy cost that necessitates its high utilization rate to be economic, and therefore confines it to parts of the net load curve with high frequency.

We can visualize this directly by comparing the CUF of the BES facilities calculated on a power (CUF_P, Panel B of Figure 4 above) and energy basis (CUF_E, Panel C). The CUF_E can be thought of as approximating the utilization rate of the depth of discharge of the BES facility: a high CUF_E equates to high utilization rate of the full depth of discharge of the BES facility. Panel C shows that the LCOE from the BES facility is inversely correlated with the CUF_E of the BES facilities. Overbuilding the energy component of the BES facilities to deal with very infrequent, long-duration gaps in the net load curve is thus not an economic strategy for the model, which instead prefers to build low sunk cost natural gas facilities, benefiting from their low capacity cost and zero sunk energy cost.

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4 In reality, because of the impact of CUF on heat rate, as well as start up and shut down costs, the energy component of the LCOE of conventional generators does vary as a function of CUF, but to a lesser degree than the power component of LCOE, which is a true sunk cost.

5 This is true when the system boundary is limited to the power plant itself. If one takes the broader natural gas system as the system boundary, then clearly the utilization rate of the assets of that system (pipelines, regassification facilities, etc.) clearly does impact the unit cost of its output. This dynamic may need to be taken into account for deep decarbonization scenarios of the energy system, where low CUF energy system assets will be needed.

7.2 RE Penetration Scenario Family

7.2.1 Understanding the Substitution Between Fixed and Variable Costs

Section 7.1.1 above shows that scenarios with quite different penetrations of VRE actually have similar levelized system costs. How is this so? In this section, we explore this question by developing a scenario family in which new solar and wind are ramped up linearly from zero in the first scenario to 25 GW of new wind and 15 GW of new solar in the final scenario. We require the model to invest in more wind than solar because we investigate in the following section the consequences of investing in just solar to drive VRE growth.

Figure 5 shows the same information as Figure 1, this time for the RE Penetration scenario family: total levelized system costs, broken down into their fixed and variable components (left axis), and VRE as a share of total generation (right axis). Across the scenarios of this scenario family, VRE share in total generation rises from 6% in the no new VRE scenario (i.e. this is the share of existing VRE) to a maximum of 55% VRE. It is immediately apparent that levelized system costs actually change relatively little across such a wide range of VRE penetrations. The key reason why they do not is **the substitution between fixed and variable costs.** The zero new VRE scenario has much higher levelized variable costs, because much more power must be dispatched from high marginal cost generators, including new gas and new coal. As the share of VRE increases, the levelized variable costs go down, as zero marginal cost VRE substitutes for high marginal cost conventional generators (both existing and to a lesser extent new build).[6] On the other hand, the system-wide per unit fixed costs go up, as the CUF of the assets in the system goes down. Two effects drive the increase in per unit fixed costs. Firstly, the growth of VRE entails the growth of a fixed cost-only technology with low CUF. Secondly, as VRE grows, the CUF of the residual assets (existing and new build) required to meet net load goes down, as their output is 'cannibalized' by VRE.

Importantly, this effect of savings on variable costs and increases in fixed costs allows **substantial cost savings compared to a scenario with no new VRE.** The per unit system cost of a scenario with no new VRE is 4.7% higher than a scenario with optimal VRE penetration. On the other hand, there are limitations to this effect. After the level of optimal VRE is crossed, the opportunity for further savings on variable costs is outweighed by the increase in per unit fixed costs, and the per unit system cost starts to rise. The highest VRE scenario has a system cost that is 2.3% higher than a scenario with optimal VRE penetration.

Figure 6 shows this dynamic in another perspective. Panel A shows the marginal gross savings on variable costs and marginal gross increases in fixed costs as a function of VRE penetration. In this case, marginal means the system-level savings or costs *at the margin* from moving from VRE penetration 'X' to VRE penetration 'Y'. These can also be thought of as demand and supply curves: the opportunity for savings on variable costs determines the 'demand' for increasing VRE, the increase in per unit fixed

6 In a model with unit commitment and heat rate degradation, this effect would be moderated, but not obviated, by rising per unit variable costs from heat rate degradation and start up and shut down costs. It is possible for per unit variable costs to go up for conventional generators, even while levelized ***system variable costs*** go down as less and less of total generation carries a variable cost at all.

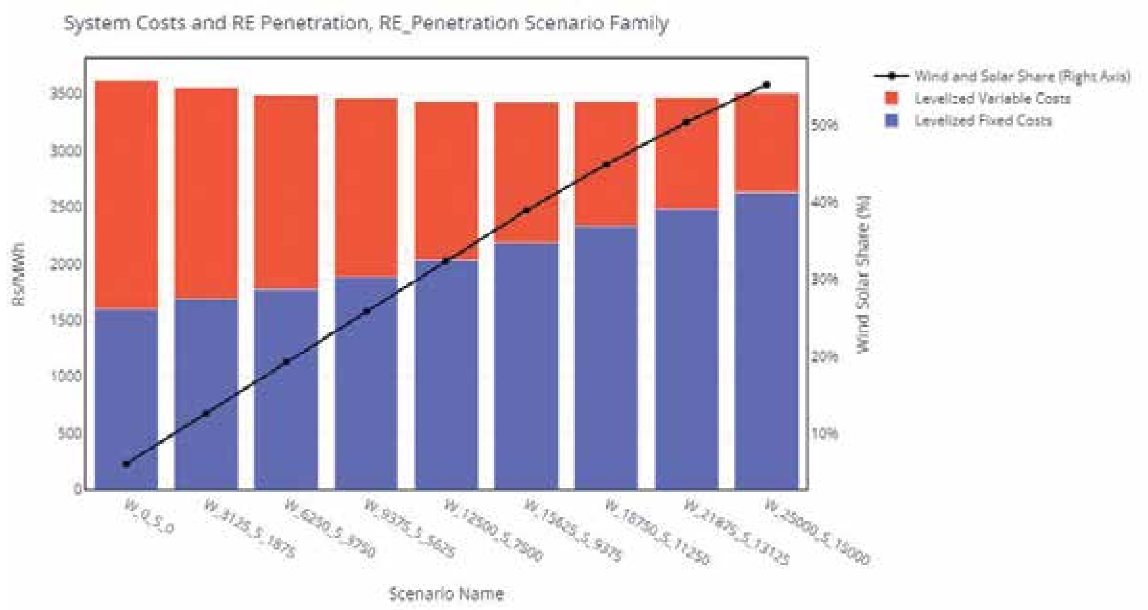

Figure 5: Levelized System Cost and Share of Wind and Solar in Total Generation

Source: authors. Note: in the scenario names W refers to wind, and the number following to the MW of new wind in the scenario. Likewise, S refers to solar, and the number following to the MW of solar in the scenario.

costs represents the 'supply' curve for doing so at the system level. As with basic economics, the optimal level is determined by their intersection: another marginal increase in VRE shares would generate gross savings on variable costs that would be exceeded by the gross increase in per unit fixed costs. Panel B shows this directly, representing the net marginal savings or costs. When the curve crosses the zero line, net benefits are exceeded by net costs, and the optimal level of VRE has been exceeded. On the other hand, a position substantially to the left of the intersection with the zero line implies that significant marginal savings could be achieved from higher penetration of VRE.

The figures elucidate the key dynamic driving the short-term optimum of VRE penetration: the substitution between variable and fixed costs. This point is determined by numerous factors, including:

» the level of variable costs and the LCOE of VRE (which determines the scope for cost savings on system variable costs);

» the capital intensity of the residual assets required to meet the net load (the higher the capital intensity, the faster per unit costs will increase with decreasing CUF);

» and the degree of correlation between VRE output and load (the higher the correlation, the less additional assets may be required to serve the net load).

The key point coming out of this analysis is that **given the costs foreseeable for the coming decade, the short-term equilibrium favours substantially higher shares of VRE than present today.**

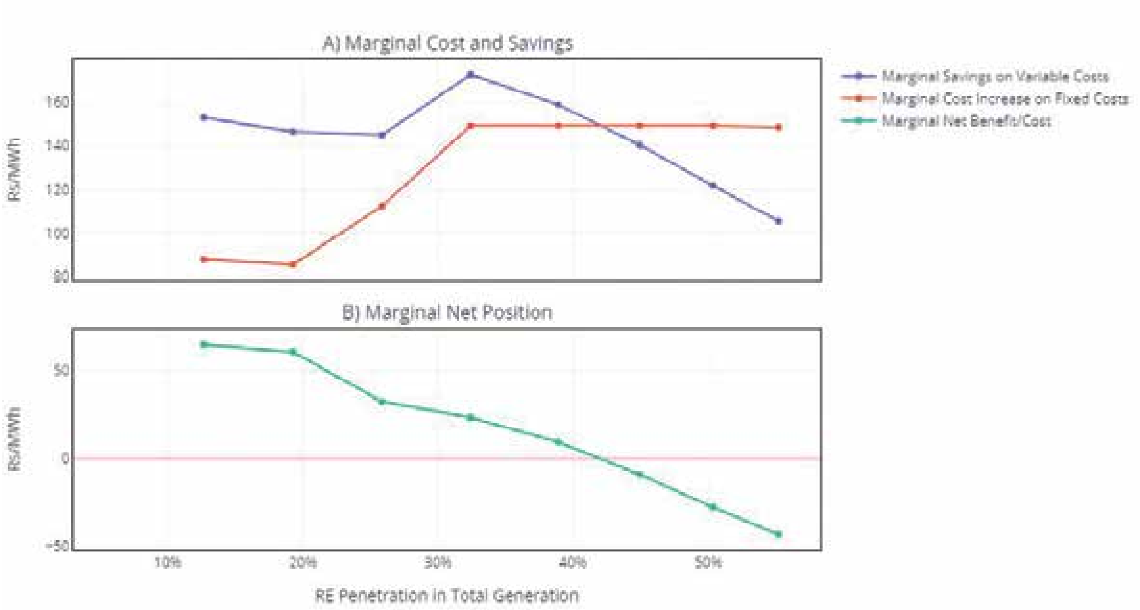

Figure 6: Marginal Gross Savings on Variable Costs, Gross Increases in Fixed Costs, and Marginal Net Position

Source: authors

7.3 Solar Penetration Scenario Family

7.3.1 Solar Drives the System Role of Storage

The same dynamic as shown in Figures 5 and 6 is present also in the Solar Penetration scenario family, where the growing share of VRE is driven solely by the growth of solar.[7] We therefore do not present it again. Rather, here we focus on the interaction between the growing share of solar and the model deployment of BES. Figure 7 shows the model deployment of BES in energy and power terms in each of the scenarios of the Solar Penetration scenario family, as well as the derived indicator of the energy/power ratio, i.e. storage duration. An interesting dynamic emerges. Firstly, as noted above, the model finds it cost optimal to have some BES even if no new solar is built. This suggests that BES is already a competitive technology for meeting daily peaking requirements, independent of the supply-side variability introduced by solar.

Secondly, the amount of storage found optimal by the model, in both power and energy terms, is relatively flat up to a certain level of solar penetration, and then increases substantially and continues to increase with rising solar penetration. This is because beyond the threshold level, the model can no longer back down thermal to accommodate solar injections and must chose between investing in storage or curtailing solar. The model does both in substantial quantities. It is worth noting explicitly that this inflection point would be reached much sooner in a model with unit commitment, and therefore the storage requirement would start to grow at lower penetrations of solar.

[7] The crossover point between savings on variable costs and increases in fixed costs was reached a little earlier in the solar penetration scenario family, at about 38% share of VRE. By 40 GW of new solar, the levelized system cost is 7% above the system cost at the optimal level of VRE.

Several key points come out of this analysis. Firstly, it is not just the 'supply' of technologies that determine their uptake, but also the 'demand' of the system. This may seem like a banal point, but we dwell further on its importance in the conclusion. In this case, the growing share of solar introduces a supply-side daily seasonality that can be cost-effectively addressed by increasing BES. Secondly, even as it increases the BES quantity and duration, the model still finds it necessary to build some additional new gas (1.6 GW in the highest solar scenario). This is because even with large quantities of long duration BES, there are parts of the net load curve that cannot be addressed by BES.

The above discussion raises two question. Firstly, what energy cost of storage is sufficient to change the economics of solar PV, all other things being equal? Secondly, what energy cost of storage is sufficient to allow storage to play a role in seasonal balancing, replacing the need for new gas? These questions form the subject of the next section.

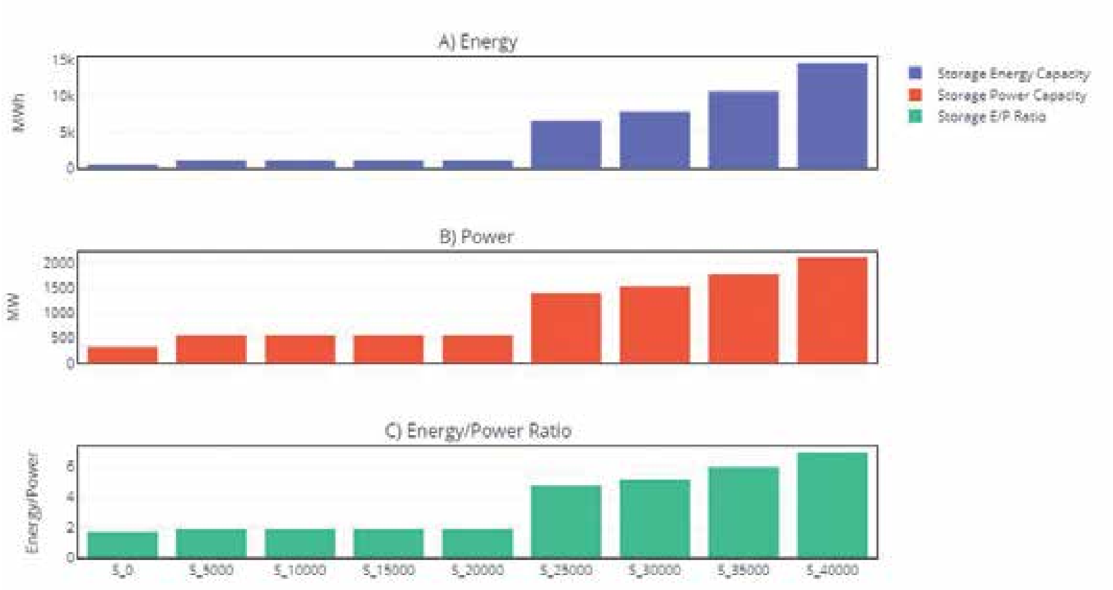

Figure 7: Model Deployment of BES in Energy and Power Terms, Solar Penetration Scenario Family

Source: authors

7.4 Storage Cost Scenario Family

7.4.1 Energy Cost of Storage Thresholds

In this scenario family, we linearly decrease the energy cost of BES from 200 USD/kWh, i.e. above today's likely level, to 20 USD/kWh, i.e. well below the most optimistic long-term forecasts for the energy cost of li-ion battery. The lowest energy cost of storage in this scenario might be seen as approximating the energy cost of a long-term seasonal storage technology (Schmidt et al., 2019).

Figure 8 shows the capacity build out in the storage cost scenario family, where all assumptions other than the storage energy cost are held constant at their baseline values and the model is left to optimise the rest of the system. The results indicate several thresholds for the energy cost of storage at which the model selects different capacity combinations. At storage costs below 200 USD/kWh, i.e. above the

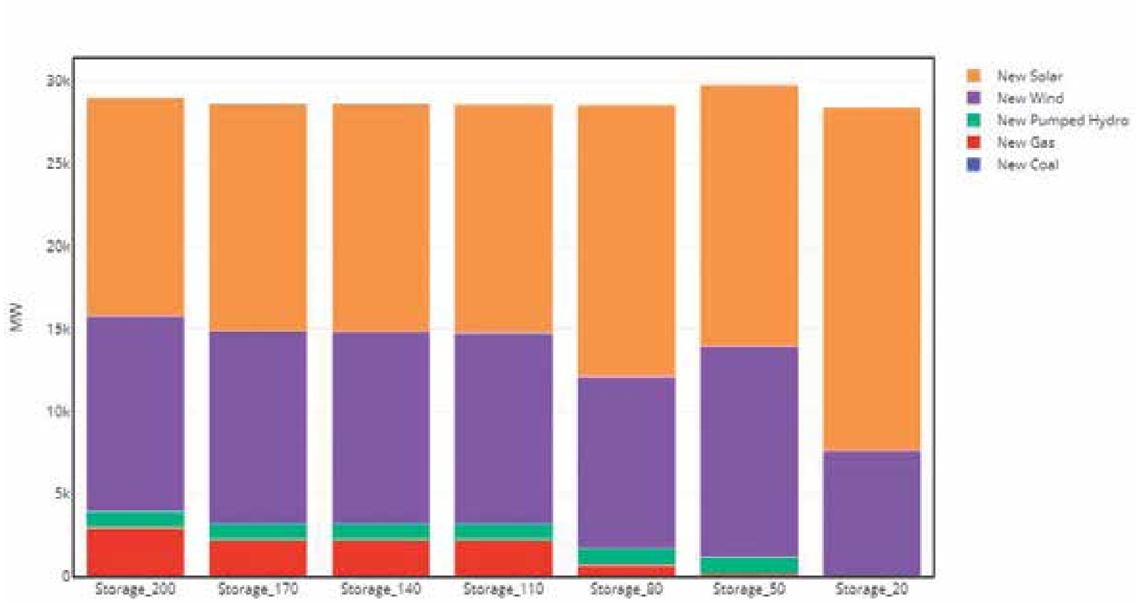

Figure 8: Capacity Build Out in the Storage Cost Scenario Family

estimated energy cost today, the model starts to reduce the investment in new gas, by about 800 MW. The next large step change occurs between 110 – 80 USD/kWh, at which point the model finds it optimal to build out an additional 2.8 GW of solar, and halves the new build of gas. It is widely expected that energy costs of BES would reach this level by 2030 (Deorah et al., 2020). At energy costs of storage of ~50 USD/kWh and lower, complete substitution of natural gas starts to occur. This gives an indication of the energy cost of long-term storage options that would substitute natural gas.

A key conclusion emerging from this analysis is that the identified energy cost threshold, *at which the economics of storage alone is enough to drive additional solar beyond the substantial amounts added in the baseline,* is located at levels more likely to be reached in the next 5–10 years.

8. Conclusions

Five key conclusions emerge from this analysis, which we detail here:

1. *The short-term optimal VRE level is substantially above the current levels, and in the order of ~40% of generation.* This conclusion holds across almost all of our scenarios, except those in which VRE is endogenously restricted (Low_RE scenario) or economically restricted by high discount rates (High_Discount rate scenario). Alternatively, if neither new gas nor sufficient purchases from the market are available and the model is forced to build some high fixed cost coal, then the high fixed costs of the new coal build place a floor on the optimal level of VRE at ~35% of total generation.

2. *The short-term optimal VRE is determined by the trade-off between variable cost savings and per unit increases in fixed cost.* This trade-off is neither universal nor static. In high variable cost systems (for example the Southern states in India), the opportunity for variable cost savings will be higher. In low variable cost systems, like the coal state in Eastern India, the opportunity for variable cost savings will be lower. In high fixed cost systems, for example with lots of young high fixed cost assets, the per unit fixed cost increase will rise faster with increasing VRE shares. Likewise, policy can shift this trade off, for example through better grid integration across India, removing the need for high fixed cost new assets and optimizing the use of 'spare' existing assets across the country.

3. *This analysis suggests that we can think of two phases of VRE deployment in high coal systems.* In the first phase across roughly the coming decade, the VRE build out is economically determined by the opportunities for this arbitrage between variable and fixed costs, plus the incremental demand growth. The analysis in this paper suggests that within the Indian system this phase would enable shares of VRE already of 40%, *even accounting for the impact on the sunk costs of the existing system.* In the second phase after 2030, as demand continues to grow and the energy costs of storage fall below the identified threshold of ~80–100 USD/kWh, the economics of VRE build out take on the characteristics much more of a greenfield system, and VRE takes essentially all of incremental demand growth.

4. *VRE makes its own economics of the power system.* In the discussion above, we noted that the economics of generation and storage options is determined not just by their characteristics ('supply'), but also by the needs of the system ('demand'). Cheap VRE is so cheap that it is preferred for whatever parts of their load curve it can serve. As its share increases, VRE begins to determine the economics of the rest of the power system. There is not enough of the net load curve to make new coal economic, because its CUF is too low to justify a capital-intensive technology. As VRE increases, particularly if it is solar dominated, the seasonality introduced starts to make substantial BES attractive because it is required on a frequency that allows the per unit *power and energy costs to be attractive.* As VRE share increases, the need arises for some form of seasonal balancing to address low-frequency 'gaps' in the net load curve, that must be addressed by some kind of seasonal balancing.

5. *Addressing this seasonal balancing should minimize sunk costs.* The most cost-effective way of doing this is to enhance the grid integration of the Indian system, allowing complementarities between demand and supply across states and regions to supply this seasonal balancing. This

would ensure optimal use of the existing sunk costs of the assets in system by maximizing their usage (including the currently stranded gas capacity). The next best option appears to be brownfield pumped hydro, where reservoir capacity is already existing. This is because its sunk cost is likely to be lower than that of gas. Finally, some gas capacity – likely open cycle to minimize gas costs – may be necessary as a last resort, given its low sunk cost and low CUF. This low CUF renders its high energy cost essentially irrelevant from a system cost perspective. But additional coal appears economically unviable, because its high sunk costs mean it can only be competitive at high CUF (and cheap VRE will occupy so much of the net load curve that high CUF is unattainable).

Finally, the results suggest that in the short-term it is unlikely that VRE will cross thresholds at which it would drive substantially higher system costs. Thus, it appears more important to focus policy on how to minimize and allocate *gross costs* in the system (i.e. high cost, low CUF assets, if required), and maximize gross benefits (by avoiding dispatch of high variable cost plant). In this way, it can be assured that the short-term ramp up of VRE can bring net benefits.

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