Initial insights from modelling the MSEDCL power system for 2029-30

A production cost simulation exercise

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***Abstract*— The power sector in India is in a state of flux. Some of the reasons for the flux are global phenomena such as reducing RE and storage prices and advances in smart grid infrastructure, while others are specific to the policy and regulatory environment in India such as the move to universal access to electricity, migration of large consumers to open access and captive options, stranded generation capacity and financial situation of distribution companies. These changes have significant implications for generation and transmission capacity planning, regulations and grid operations. However, there is considerable uncertainty in how these changes will pan out over time since a lot of factors that affect these changes are beyond the control of system planners. In this context, appropriately set up power sector models provide significant insights that can help formulate better strategies and make more informed decisions. We describe a production cost simulation model for the state of Maharashtra for the year 2029-30, and illustrate some initial insights that are relevant for electricity planners, distribution utilities, regulators and system operators in Maharashtra as well as the rest of India.**

Power sector modelling, production cost simulation, Maharashtra, MSEDCL, grid integration, renewables, storage, India, 2030

I. Introduction

India has made strong commitments to scale up renewable energy (RE), mainly to take advantage of the abundant wind/solar resource in the country, low cost discovery (Rs 2.5-2.75/kWh) and fixed price long term contract nature of wind and solar power. In a draft report titled 'Optimal Generation Capacity Mix for 2029-30', the Central Electricity Authority (CEA) has projected RE capacity as high as 450 GW (54% of total capacity) by 2029-30. [1] In stark contrast, prices of new coal generation are rising fast even without considering the additional costs of complying with the stricter environmental norms set by MoEFCC. Reliably integrating this level of renewables will imply significant new technical and economic challenges. This includes need for flexible resources for better system balancing. These could be from flexible operation of thermal power plants, open cycle gas plants, batteries and changes in system planning/operation rules such as greater balancing areas and broader and deeper markets.

While the financial health of the state distribution companies is already very weak, it could worsen with ever-rising sales migration to open access, captive generation and rooftop solar. However, managing such uncertainties is the responsibility of the states/DISCOMs, since ultimately they manage power procurement and are responsible for reliability and affordability. To facilitate better preparedness towards this transition with its myriad uncertainties, there is a dire need to use better analytical and modelling tools to inform policy and regulatory decision making.

II. Why Production Cost Simulation?

It is clear that the future will have an ever increasing share of RE due to its various advantages – low and fixed cost, abundant resource, local environmental advantages, climate mitigation, low gestation periods, etc. The diurnal, seasonal nature of RE generation along with its near-zero marginal costs coupled with the potential changes in load growth and profiles due to a combination of sales migration and newer load like electric cooking and mobility has the potential to make a paradigm change in system operation in the medium to long term. Thermal power plants will need to operate much more flexibly to accommodate these changes.

Detailed production cost simulations can significantly aid planning in this process since they allow users to find out various ways to provide reliable power supply, while minimising system costs within specified technical and economic constraints. They incorporate important technical constraints of dispatch-able generation sources such as technical minimum, ramp rates, min up and down times, and start and shutdown profiles. In order to get robust insights for planning and system operation, effects of uncertain events such as intermittent generation, fuel availability, outages, load profiles and market purchases can be studied by using scenarios or stochastic modelling.

A. Our Approach

The initial phase of the exercise involved validating the model for the base year, i.e., 2017-18. This was followed by exploring optimal supply mix strategies for different years over the next decade, especially 2021-22, 2026-27 and 2029-30. Of these, we focused on the year 2029-30 since it gives sufficient time in terms of planning horizon and battery storage costs are expected to come down significantly by then. After running several scenarios with different cost trajectories and capacity shares, we identified two scenarios that showcase orthogonal strategies for power purchase planning for the MSEDCL area. These scenarios differ by the share of RE in the system, namely – a coal dominant scenario with 20% generation share of RE (not including large hydro), and a high RE scenario with 40% RE. These scenarios were chosen since they facilitate analysis of the integration challenges with higher shares of renewable energy in the MSEDCL system.

We have considered four parameters for analysing the results of the model and compared the two short-listed scenarios: (a) reliability (shortage quantum and profile), (b) system operation in stress hours/months, (c) capacity utilisation, part-load operation and number of starts for thermal units, and (d) variable and total costs.

III. Model Setup, Assumptions and Scenarios

We have used the PLEXOS platform for this modelling exercise. The model is a single node, copper plate model, i.e., there are no transmission constraints. Despite this, we find that the model can offer significant insights for power procurement planning in the context of the parameters considered for analysis listed in the previous section – reliability, system operation in stress periods, operation of thermal units and costs.

The model has a dispatch interval of 15 minutes with dispatch being optimised for each day of the year, with an additional look-ahead day (dispatch results for the look-ahead day are discarded). In addition, planned maintenance of thermal units and hydro generation are optimally scheduled over the year based on the load and generation profiles using the PASA and MT schedules in PLEXOS.

Inputs to the model are derived from various public sources, mainly regulatory documents and operational data published by various sources including the state and central electricity regulators, state, regional and national load dispatch centers and MSEDCL.

The base year of the model is 2017-18 and data from this year was used to project inputs for future years. The model was run for the year 2029-30.

A. *Demand-side Assumptions*

Load profile is based on hourly load data from the year 2017-18 that is submitted by MSEDCL to the Maharashtra Electricity Regulatory Commission (MERC) [2]. This load data is nearly identical to the hourly data published by the Maharashtra State Load Despatch Center (MHSLDC) [3]. This load profile is adjusted for open access generation as reported by MSEDCL and rough estimates of about 1000 MW generation capacity that is contracted by MSEDCL but not monitored by MHSLDC[1]. This profile is then resampled to a 15-minute interval in sync with the model resolution. Demand is assumed to increase at a compounded annual growth rate of 3.85% (as approved by MERC in the multi-year tariff period 2016-17 to 2019-20) until 2029-30. Thus, a peak load of 19,533 MW and energy requirement of 129,605 MUs in 2017-18 increases to a peak load of 30,019 MW and energy requirement of 203,939 MUs in 2029-30. Finally, the load profile is modified by shifting 4000 MW of non-monsoon agricultural night time (10 pm to 7 am) load to day time (8 am to 5:30 pm), in line with the solar agriculture feeder policy in Maharashtra [4]. This results in a peak load of 33,895 MW and energy requirement of 203,939 MUs in 2029-30.

B. *Supply-side Assumptions*

Generation capacity is based on the capacity contracted by MSEDCL in 2017-18. Capacity in pipeline as indicated in regulatory submissions by MSEDCL have been considered for future years.

In the 20% RE scenario, six 660 MW coal units are added by 2029-30 to meet increasing demand. In the 40% RE scenario, two 660 MW coal units are added in place of six 210 MW coal units that are considered to be retired. The new coal capacity is categorised under the state generating company only for reporting convenience.

RE capacity is added in both the scenarios as per the share of RE generation in total demand, i.e., 20% and 40% respectively. This additional RE capacity is divided among solar and wind in the ratio of 60% and 40% respectively.

2000 MW of flexible generation is added in both scenarios. This could either be procured from the market or through open cycle gas generation.

In the 40% RE scenario, a 2500 MW/15000 MWh battery and 2000 MW/4000 MWh battery are added for diurnal balancing needs, particularly in the context of high solar capacity.

Transmission losses are considered for out of state capacity. All new capacity is considered to be geographically located in the state.

TABLE I. provides a summary of the generation capacity considered in the two scenarios.

TABLE I. Capacity Contracted by MSEDCL in 2017-18 and Projected for 2029-30

↓ Generator Category	Contracted Capacity (MW)		
Scenario →	***Actual in FY18***	***20% RE***	***40% RE***
State Genco Coal	10,170	14,130	10,230
State Genco Hydro	2,352	2,352	2,352
Central Coal	4,511	5,117	5,117
IPP Coal	5,585	5,585	5,585
Wind	3,641	8,524	15,175
Solar	987	11,781	26,484
Others	4,614	4,957	4,957
Total long-term	**31,860**	**52,444**	**69,900**
Market/Open Cycle Gas	-	2,000	2,000
Battery storage	-	-	4,500

Operational characteristics of generating units are largely based on current system operation and, in most cases, conservative as compared to norms that are considered technically feasible and being discussed for future regulations to improve system flexibility in the context of the increasing share of renewables in the grid [1] [5].

MSEDCL has significant hydro power generation capacity mainly due to the 1960 MW Koyna hydroelectric project. For Koyna, a yearly energy budget was specified in

[1] The open access generation reported by MSEDCL is subtracted from the total generation monitored by SLDC. To this 700 MW of wind generation and 300 MW of bagasse generation are added to the load, with the same generation characteristics as used in the model for wind and bagasse respectively.

the model, based on the design energy and generation over the past few years. In addition, a monthly minimum energy generation was specified based on historic generation patterns.

Generation profiles were provided for solar, wind and small hydro generators. Solar and wind profiles are based on aggregate hourly generation profiles for the state of Maharashtra during 2017-18 as reported by MHSLDC. Historic wind generation profiles were scaled up to ~28% capacity utilisation to derive generation profiles of new wind capacity to account for higher hub heights and larger rotors. These profiles are then resampled to 15-minute intervals.

C. Cost Assumptions

All costs in the model are in nominal terms. Capital cost of a new coal-based generating unit is assumed to be Rs 8 crore per MW in 2025. Solar and wind capital costs are assumed to be the equivalent of a levelised cost of Rs 2.75 per kWh in 2017-18 and subsequently increase nominally at 3% and 4% respectively year over year, resulting in Rs 3.92 and Rs 4.40 per kWh respectively in 2029-30. Battery costs are assumed to be Rs 15,000 per kWh for a 6-hr battery and Rs 22,500/kWh for a 2-hr battery in 2029-30. Variable cost of coal is assumed to increase nominally at 5% year over year. New coal capacity is assumed to have a variable cost of Rs 2.5 per kWh in the base year and increases to Rs 4.49 per kWh in 2029-30. In addition, cost of coal based units complying with recent environmental norms is considered to be 30 paise per kWh. The market/open cycle gas is assumed to be available at zero fixed cost and a variable cost of Rs 12 per kWh in 2029-30. Transmission costs have not been considered in the model.

IV. Results

Figure 1. shows the daily generation stacks from the two scenarios. As expected, wind generation is high in the monsoon period while coal-based generation dominates throughout the year in the 20% RE scenario. In the 40% RE scenario, there is significant solar generation throughout the year, while wind dominates during monsoon.

A. Reliability

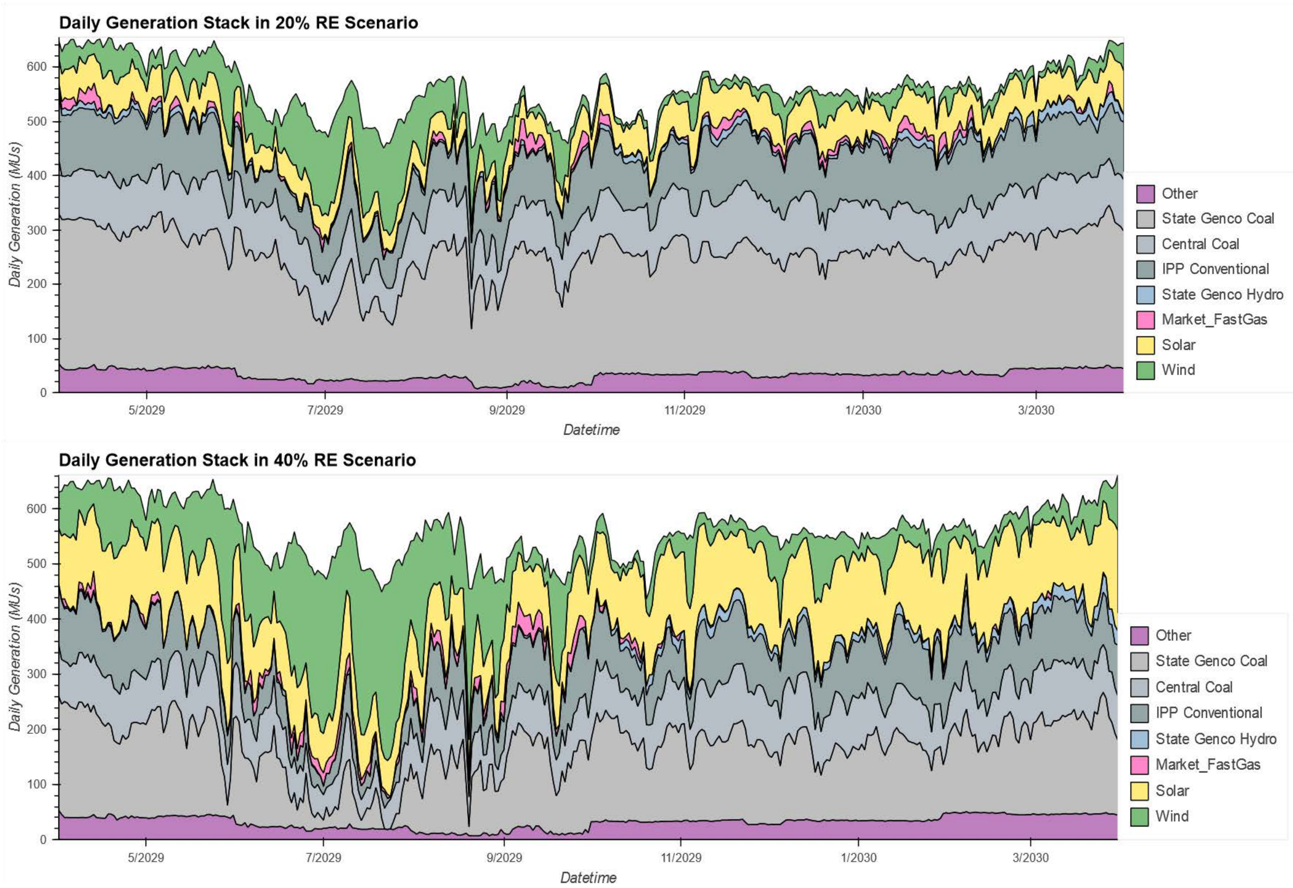
Shortages are observed in both the scenarios. This is partly expected since short term power source is exogenously limited to 2000 MW of high cost flexible generation source or market purchase. The 20% RE scenario has an annual shortage of 92 MUs (< 0.05% of total demand) and the 40% RE scenario has an annual shortage of 180 MUs (< 0.1% of total demand). TABLE II. shows the profile of shortages in both the scenarios.

TABLE II. Profile of Shortages in 2029-30

	Number of 15-min blocks with shortages	
Shortage (MW)	***20% RE***	***40% RE***
> 3000	14,130	10,230
> 2000	2,352	2,352
> 1000	5,117	5,117
> 500	5,585	5,585

Many of these shortages, especially those above 2000 MW, are short duration episodes that cannot be predicted in advance, and hence contracting year-round capacity to meet these shortages can be very costly. Instead, market purchases or demand response measures can be undertaken to address these shortages.

Figure 1. Daily generation stack in the 20% and 40% RE scenarios



B. System operation during stress periods

Stress periods occur during the following periods: (a) April-May, when demand is high, (b) September, when maximum shortages occur, and (c) monsoon, when there is significant wind generation resulting in curtailment during the day. It should be noted that the specific days when stress points occur in the system are a relic of specific weather or other conditions in the base year, because the actual demand, solar and wind profiles from that year are extrapolated to 2029-30. While stress periods in 2029-30 may or may not occur on those exact days, the simulation is still valuable since similar conditions may occur at other times. Figures Figure 2. - Figure 4. show illustrate a few stress events in the 40% RE scenario.

Figure 2. shows the balancing role played by battery storage on the day in which yearly peak demand occurs (April 18). Generation above the load line during the day is used to charge the battery, which is discharged during early morning and late evening times when there is a steep change in solar generation.

Figure 2. Maximum load day (April 18) in 2029-30 in 40% RE scenario

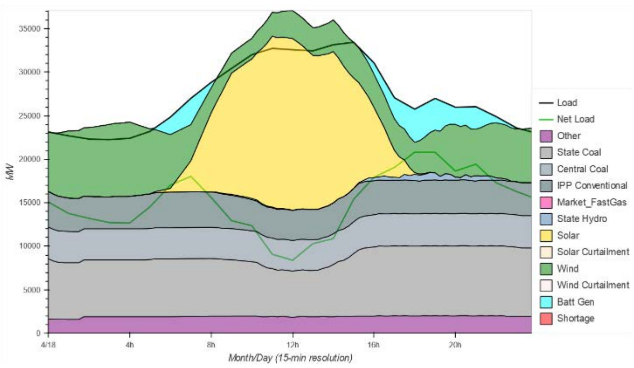


Figure 3. depicts how the system operates during the week of September 3rd when significant shortages occur. This week is marked by significant variation in wind generation due to which there are shortages during the night time since coal based generation cannot be ramped up as quickly. The 2000 MW flexible generation is fully utilised as well. Such events are rare and can be addressed with a combination of better forecasting and scheduling of RE generation, committing coal generators online and curtailing some RE generation as needed. In the extreme event when none of this works, demand response resources can be tapped into. These have not modelled as part of this exercise.

Figure 3. Maximum shortage week (Sep 3-9) in the 40% RE scenario

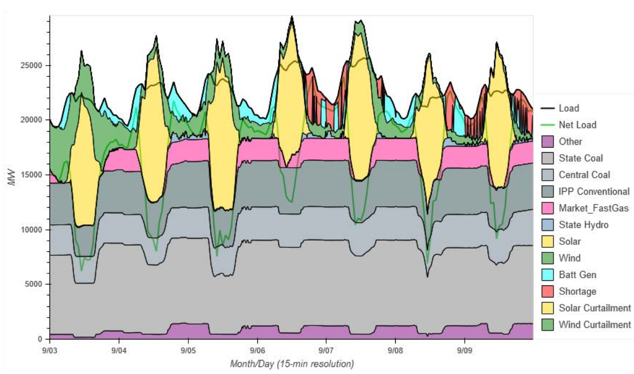
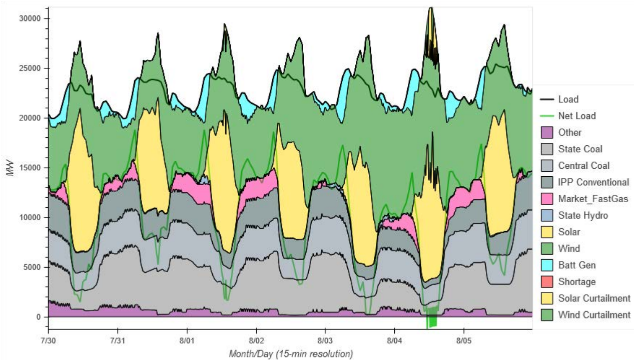


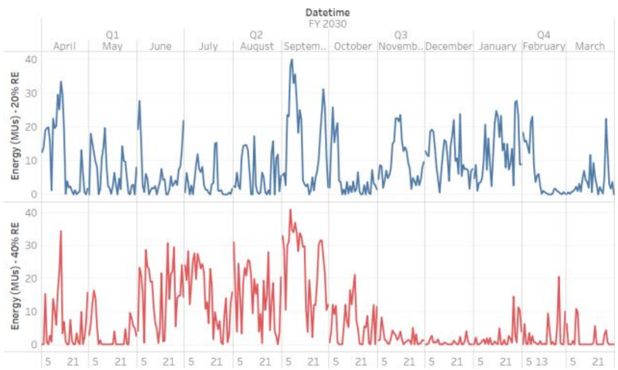
Figure 4. shows a typical monsoon week when some curtailment is observed in the simulation. When net load (load minus non-dispatch-able generation) is extremely low, battery is fully charged and thermal fleet is operating at technical minimum, RE is curtailed. RE curtailment is observed in both scenarios, but is more pronounced in the 40% RE scenario at 1350 MUs over the year. However, this accounts for only ~1.78% of solar and wind generation, and hence is not of significant concern.

Figure 4. Monsoon week in the 40% RE scenario



As indicated earlier, a generation source of 2000 MW has been provided in both the scenarios as a proxy for a flexible resource such as open cycle gas generation or high cost purchases from the market. It is seen that this resource is accessed throughout the year, but there are some differences between the two scenarios. Figure 5. shows the generation profile of this resource in both the scenarios. Whereas it is accessed uniformly throughout the year in the 20% RE scenario, it is accessed minimally in the Nov-Jan period but heavily during high wind periods in the 40% RE scenario. Nevertheless, the annual capacity utilisation of this resource is ~17% in both the scenarios and, at ~2800 MUs, it accounts for less than 1.5% of the annual demand. This insight is especially useful in the Indian context as regulators are often reluctant to approve high cost short-term power when the company is backing down some of its baseload units.

Figure 5. Daily energy from market/open cycle gas in both scenarios



C. Operation of thermal units

The technical characteristics of coal based units considered in the model, such as technical minimum, ramp rates and minimum up/down times, are quite conservative for 2030 relative to recent discourse on increasing flexibility of the coal fleet [5] [6] [1]. These are hard constraints in the simulation, hence they are never violated. Apart from these parameters, the other important factors that impact performance of coal based units are unit loading levels and number of starts.

TABLE III. shows a comparison of the coal plant load factors (PLFs) between the two scenarios. As expected, while PLFs are lower in the 40% RE scenario, they are not too low and comparable to the current (2019-20) PLFs of various coal generating units around the country. On the other hand, PLFs in the 20% RE case are above 70%, indicating that high availability (85%+) becomes an important requirement. This implies reliable availability of coal and good O&M practices of coal generating units. The differences in PLFs across generator categories is a reflection of the relative order of generating units on the merit order stack.

TABLE III. CATEGORY-WISE PLFS IN BOTH SCENARIOS IN 2029-30

Generator category	***20% RE***	***40% RE***
State Genco Coal	71%	60%
Central Coal	77%	71%
IPP Coal	73%	63%

Figure 6. shows the unit loading levels by generator category. It is observed that both state Genco and IPP units are in zero loading state for a significant amount of time, especially during monsoon. These units also operate at 55-75% loading for 10-25% of the time during the non-monsoon months. Central units operate at 55-65% loading for 10-25% of the time during monsoon months. This has implications for unit operating efficiencies, implying that generators need to be compensated for part load operation, thus increasing system operating cost. We have not modelled part load heat rates and their cost implications in this simulation.

Figure 6. Generator category-wise unit loading in the 40% RE scenario

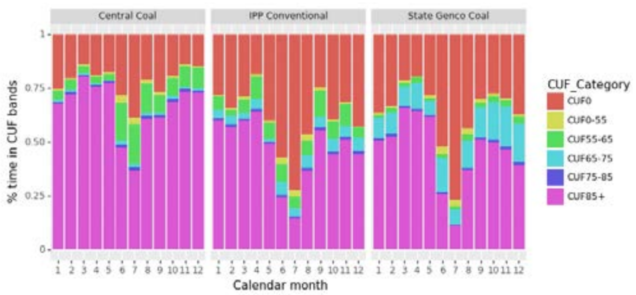
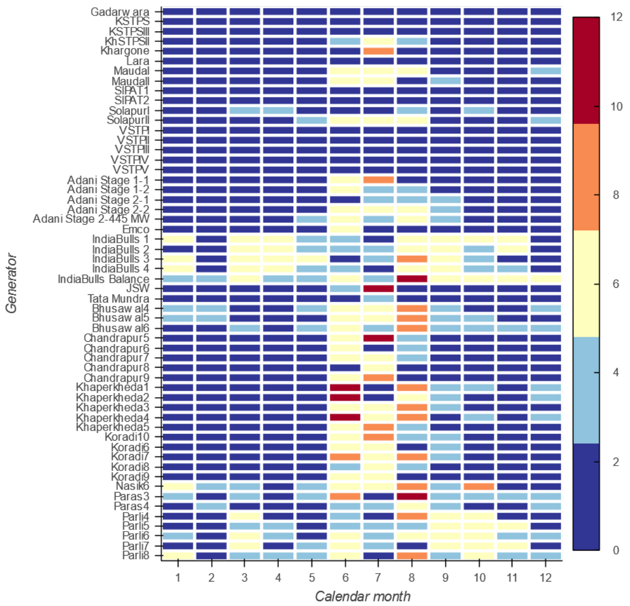


Figure 7. depicts unit-wise number of starts per month in the 40% RE scenario. There is significant cycling of plants during monsoon with some units starting 10-12 times a month. This implies significant stress on generating unit operations and perhaps a need for higher repair and maintenance (R&M) to account for the wear and tear caused by cycling. Strategies such as opportunistic RE curtailment and better integration with regional and national markets could also be explored to reduce coal start-stops.

D. Operational and fixed costs

There is very little cost difference in the two scenarios. The variable cost in the 40% RE scenario, which includes total RE costs, is lower than the 20% RE scenario by ~3.5%, while the total costs, including fixed costs for battery and new coal units, are higher by ~1.3% in 40% RE scenario. These cost differences are quite low, considering that even very small changes in the future cost assumptions can tilt the costs one way or the other.

Figure 7. Coal unit-wise number of starts per month in 40% RE scenario



E. Sensitivity of results to load shape and growth

Sensitivity of the results to load profile and load growth rate were analysed.

With respect to load profile, demand was increased by 5% during stress hours (5-7 am and 5-7 pm) in 2030. This did not have significant impact on reliability in both cases.

When load growth rate was changed to 5% year over year (as compared to 3.85%), there were significant shortages and additional capacity had to be added to improve system reliability. RE capacity was added in line with the % share of RE in each scenario, i.e., 20% and 40% respectively. In addition, three 660 MW coal units had to be added in the 20% RE scenario and 2500 MW/15000 MWh battery was added in the 40% RE scenario, to bring down the shortages to reasonable/similar levels. However, with this new capacity mix, the difference in variable and total costs in both the scenarios continues to be insignificant.

V. KEY INSIGHTS

Following are some key insights that emerged from this modelling exercise. These insights broadly apply to both the 20% RE and 40% RE scenarios.

- It is possible to meet demand in 2030 without any 'net addition to coal fleet' and with 40 % contribution from renewable sources. The high renewables scenario has similar reliability as the high coal scenario, with coal plants operating within current conservative technical limits (technical min, ramp up etc.). The generation cost differential between the two scenarios is negligible at less than 2%, and well within tolerance limits considering the wide uncertainty in cost trajectories.
- In the context of uncertainty in long term demand growth and profile, the modular nature of solar, wind and battery projects allows for nimbler capacity addition planning as compared to the

longer planning and gestation periods of conventional generation sources and thus have lesser risk of lock in and stranded assets.

- Availability of coal, its cost and ability of coal fleet to operate in a flexible manner are important considerations in both scenarios
- Strategies such as opportunistic RE curtailment and better integration with regional and national markets should be explored to reduce coal cycling costs.
- Shifting of night-time agricultural load to day time in line with the Maharashtra government's solar feeder policy plays a significant role in absorbing the solar power and thus system reliability. Hence, power procurement planning should take this into account.
- For reliability, it is necessary to procure high cost 'peaking' power – either from open cycle gas turbines (with a 15-20% CUF) or from the market. It is desirable to have seasonal, short term procurement to meet seasonal high load.
- Battery is effective in addressing diurnal shortages and absorb economical solar and, to a lesser extent, wind generation. With battery operating as a diurnal storage resource, hydro becomes more of a seasonal storage resource. This is particularly relevant for states like Maharashtra where there is significant hydro storage that can be employed exclusively for power generation purposes.
- Demand response measures are essential to avoid sudden shortages for a few hours a year (~ 20 – 30 hours). These shortages are for such short durations that no amount of capacity addition planning can economically address them.
- Some immediate policies or regulatory actions could be considered as part of multi-year tariff process to respond to some of the current and upcoming trends
- Seasonal tariffs could be set to take into account load and variable RE generation patterns. Simultaneously, the distribution utility could explore seasonal short term procurement contracts to account for these patterns.
- The time-of-day (ToD) regime could be expanded down to 5/10kW+ consumers and the peak tariff slot should be adjusted based on load and generation patterns.
- Prior approval can be sought by the distribution utility for peak / exigency power procurement based on a robust modelling exercise.
- Procurement of grid scale battery storage should be initiated on a pilot basis to explore and understand its utility in providing various grid services such as generation balancing, ancillary services and strengthening/better utilisation of the transmission and distribution infrastructure.
- Simulations with different scenarios which vary some wind and solar properties (like location, generation profile, voltage level, and wind/solar mix) can pointedly show the value of these renewables to the system. This can inform and lead to a more structured and rigorous RE procurement and transmission planning approach which is based on the best value to the system rather than just on the least generation cost. Since the model output shows the times with energy surplus and shortage, this can be used to trade with other states/consumers, subject to adequate transmission capacity. Similarly, the higher ramp requirements and frequent shutdown of plants can lead to opportunistic contracts with other states / regions.

Based on the scenario runs with different assumptions for cost trajectories, demand growth and profile, these insights appear to be robust and are relevant for medium to long term power system planning in Maharashtra. However, given the uncertainty in the sector, it is imperative that such exercises are repeated once every year or two, to update the model inputs based on changing trends, resulting in more up-to-date and relevant inputs to planning.

VI. Future Work

In this paper, we present some initial insights from modelling the MSEDCL system for 2029-30. This is work in progress, and we intend to undertake additional exercises using both production cost simulation and capacity expansion models with features such as transmission, integration with regional/national markets, real time markets, demand response, part-load heat rates and additional scenarios with different demand profiles and growth rates. Due to space limitations, we were not able to provide additional details of the model in this paper. These details and the additional analyses listed above will be published through subsequent publications from Prayas (Energy Group).

VII. Conclusion

This modelling exercise has provided useful insights on system operation and planning, especially considering the inherent uncertainty in many future assumptions and the inevitable transition to a more renewable energy based sector. It provides a sound analytical basis for decision making and can also be the starting point for objective debate and consensus building around many issues such as capacity addition and power procurement planning, identifying appropriate performance indicators for regulating baseload thermal plants, and tariff design. These insights could also be helpful in determining how to best utilise scarce natural resources such as hydropower and what role battery based storage systems can play in a cost-effective manner. Considering the various assumptions and uncertainties about the future, it is important to focus on the broad direction of the results rather than focusing on exact numbers. Finally, this has to be an iterative and continuous process and not a one-off exercise for it to be really effective in driving change.

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