Initial insights from modelling the MSEDCL system for 2030

A production cost simulation exercise

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Context

- Churn in the electricity sector
  – Falling RE and storage prices, local and global environmental imperatives, uncertain demand, utility financial situation
- A more robust approach to planning under uncertainty requires better analytical tools

Modelling approach

- Focus on state level analysis
  - Need to demonstrate value and feasibility of large share of RE at the state level
- Assess appropriateness of ‘high’ RE scenario, rather than discover ‘maximum’ RE scenario
  - Technical feasibility and cost implications
- Focus on
  - High level numbers
  - Insights about system operation, importance of various inputs & assumptions, and actions required for 40% RE scenario
  - Identify policy and regulatory approaches that need to be initiated
- Iterative process needed to account for various scenarios, sensititivities, data availability etc.

Production cost simulation

- Simulation of grid operation – unit commitment and economic dispatch
  - Minimise system cost within specified constraints
  - Capacity addition specified exogenously
  - 1 day step size with 1 day lookahead

- Generator constraints
  - Detailed modeling of technical limits of generation sources such as **ramp rates, min up/down time and start and shutdown profiles**
  - Planned thermal maintenance and hydro generation optimised over the year within specified constrants

- Platform used: Plexos

Model setup

- Base year 2017-18
- Model year: 2029-30
- Copper plate: transmission not modelled
- Load profile based on 2017-18 data from MSEDCL ARR submissions
  - Adjusted for OA, capacity not monitored by SLDC
  - Resampled to 15 minute interval
  - Modified for agricultural load shift
- Solar and wind profiles based on MH aggregate generation in base year
- New wind profile scaled up (to ~28% CUF) from existing wind profile

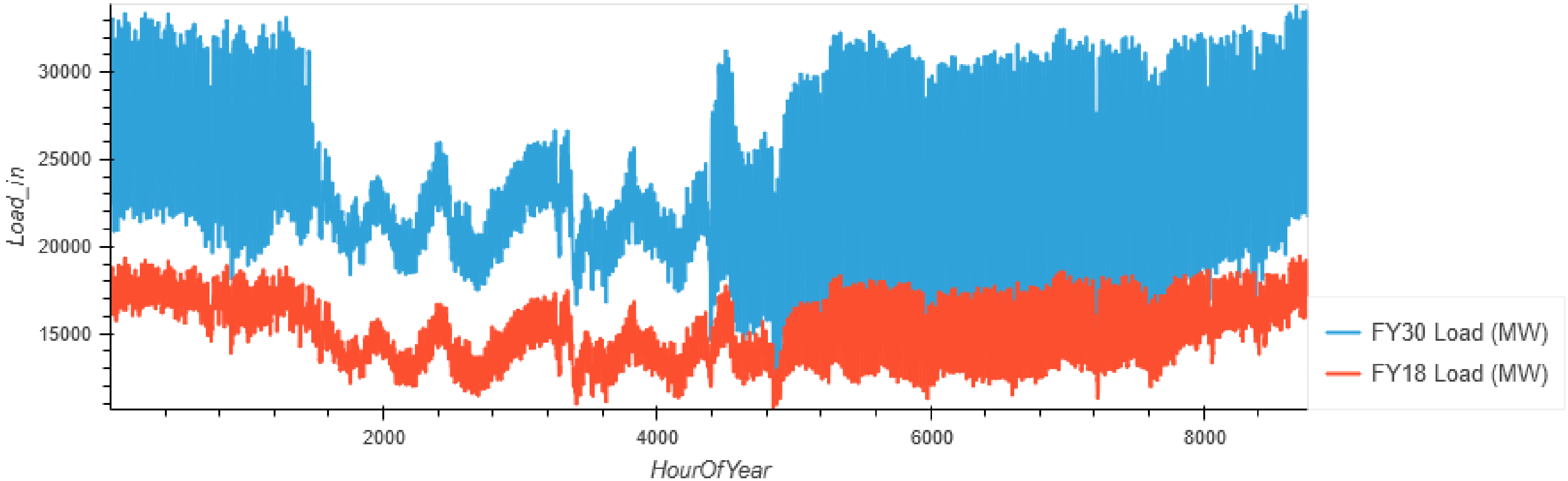
Category	Contracted Capacity (MW) in FY18
State Genco Coal	10,170
State Genco Gas	672
State Genco Hydro	2,352
Central Coal	4,511
Central Gas	461
Central Hydro	491
Central Nuclear	748
IPP Coal	5,585
Wind	3,641
Solar	987
Other NCE	2,242
Total	**31,860**

Thermal and hydro operating assumptions

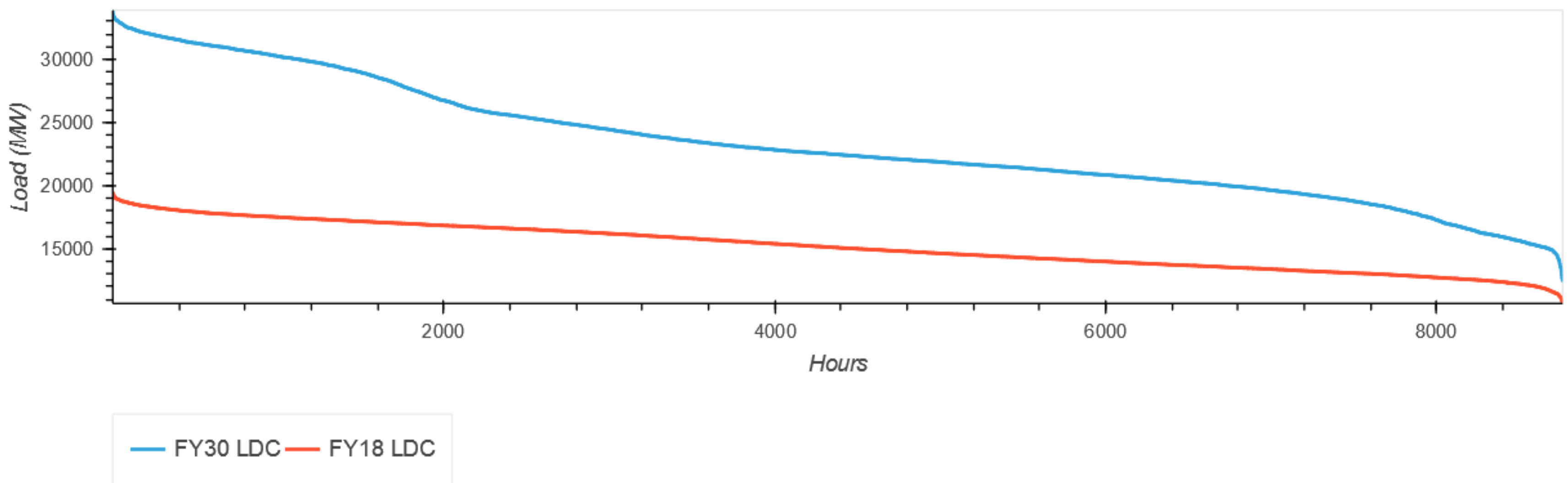
- Coal
  - Technical minimum as per current operation
    - 55% for central and ~65% for others
  - Ramp rates: 0.3-1 %/min
  - Run up (0 ↔ tech min) rates for start and shutdown
  - Min up/down time: 24 hours
  - Start costs: as per ‘Greening the Grid’ 175 GW study
  - Availability: 85%
- Hydro
  - Yearly energy budget and monthly minimum energy based on past few years

Demand in 2030

- Base demand growth rate: 3.85% p.a.
  - growth rate approved by MERC for MYT
- Load profile based on 2017-18
- 4000 MW of non-monsoon night-time agricultural load moved to day time by FY30 as per solar feeder policy



Load duration curve



Demand	FY18	FY30
Annual (MUs)	129,605	203,939
Average (MW)	14,795	23,281
Peak (MW)	19,077	33,895
Trough (MW)	10,393	12,389

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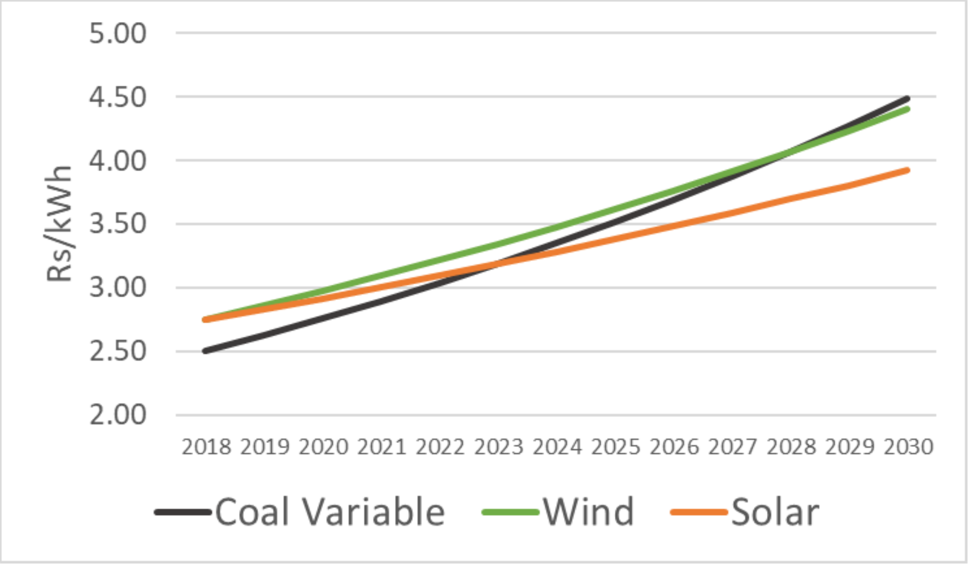
Cost projections till 2030 (all nominal)



- New Coal fixed costs based on Rs 8 Cr/MW
- Market/Flexible generation @ Rs 12/unit
- Battery considered in some scenarios
  - Cost: Rs 15000/kWh for 6 hour, Rs 22500/kWh for 2 hour
- Cost for complying with environmental norms: 0.3 Rs/unit

Scenarios

- Ran many scenarios to assess different supply mix strategies – FY 2030
- Of these, two scenarios that provide some significant insights
  - Coal Dominant – 20 % RE
  - High RE – 40% RE
- New RE generation distributed between solar and wind in 60:40 ratio
- Capacity in pipeline considered in all scenarios
- Parameters considered for analysis
  - Reliability: Shortage quantum and profile
  - System operation in stress hours/months
  - Thermal PLFs, part-load operation, starts
  - Variable/operational and total costs

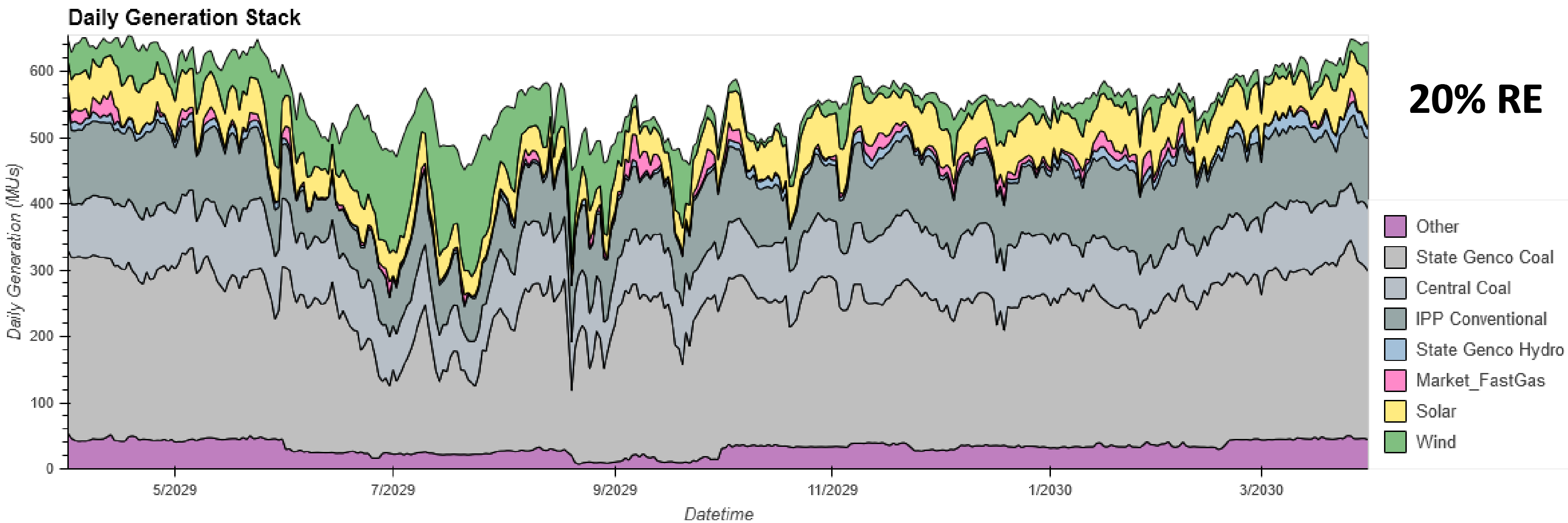
Capacity addition (MW) across scenarios

20% RE	40% RE
• Addition of 4x660 MW coal-based capacity • RE capacity addition to meet 20% generation through RE	• Considered retirement of 6x210 MW of State Genco • Addition of 2.5 GW 6-hr and 2 GW 2-hr battery

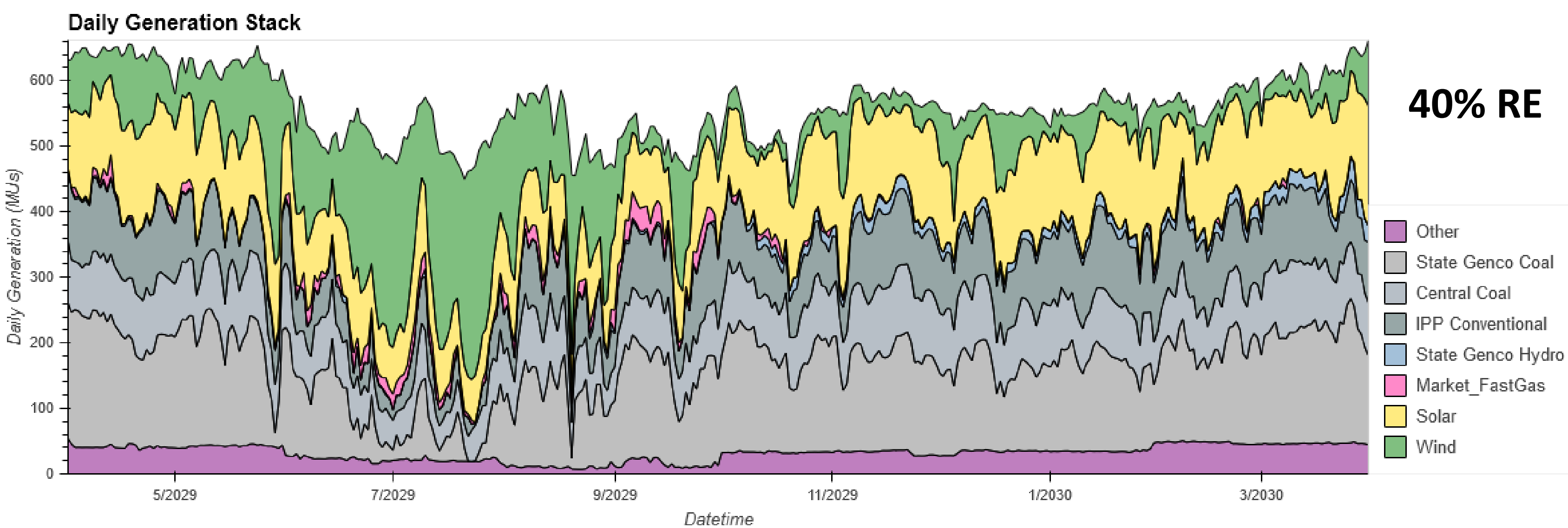
Category	FY18	20% RE in FY30	40% RE in FY30
State Genco Coal	10,170	11,490	10,230
State Genco Hydro	2,352	2,352	2,352
Central Coal	4,511	5,117	5,117
IPP Coal	5,585	5,585	5,585
New Coal		2,640	-
Wind	3,641	8,524	15,175
Solar	987	11,781	26,484
Others	4,614	4,957	4,957
Total	31,860	52,444	69,900
Market/Flexible Gen		2,000	2,000
Battery			4,500

RESULTS

Daily generation stack



20% RE



40% RE

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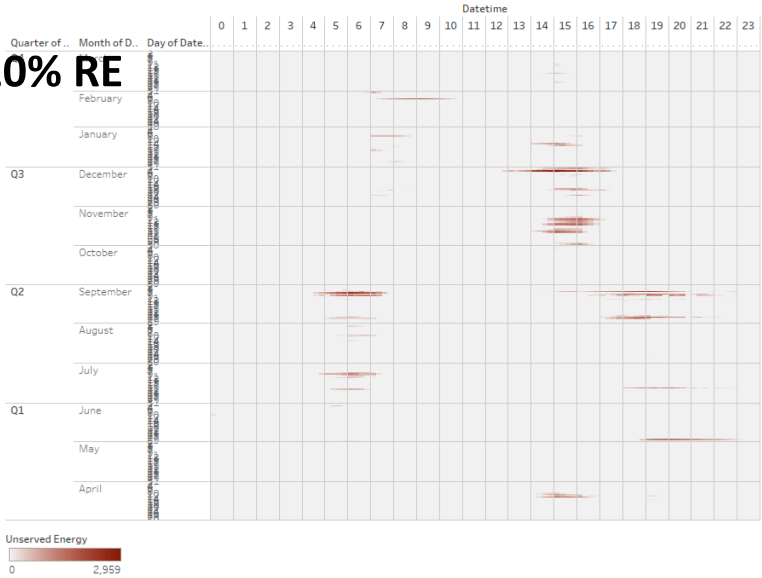
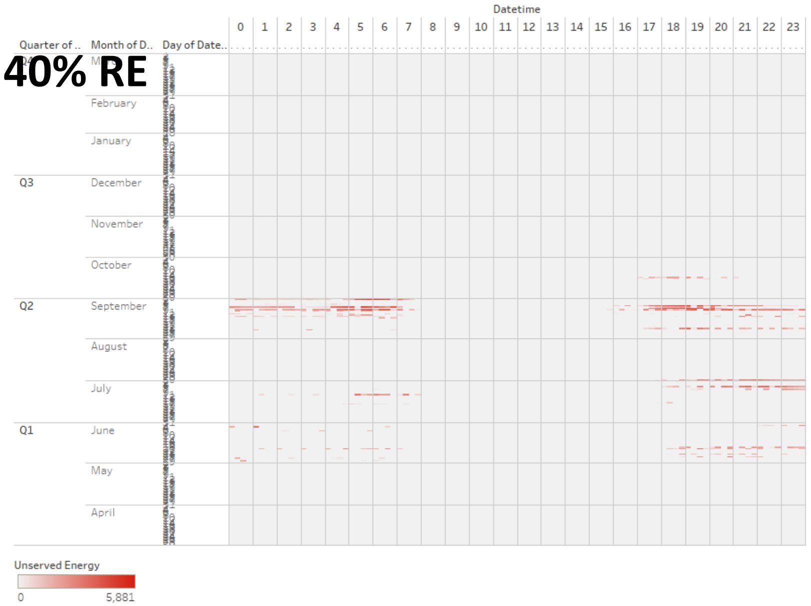
Key parameters – comparison

Category	20% RE	40% RE
Annual Demand (MUs)	203,939	203,939
Annual Shortage (MUs)	92	180
RE Curtailment (MUs)	102	1,350
State Genco Coal PLF	71%	60%
Central Coal PLF	77%	71%
IPP Coal PLF	73%	63%

20% RE



40% RE



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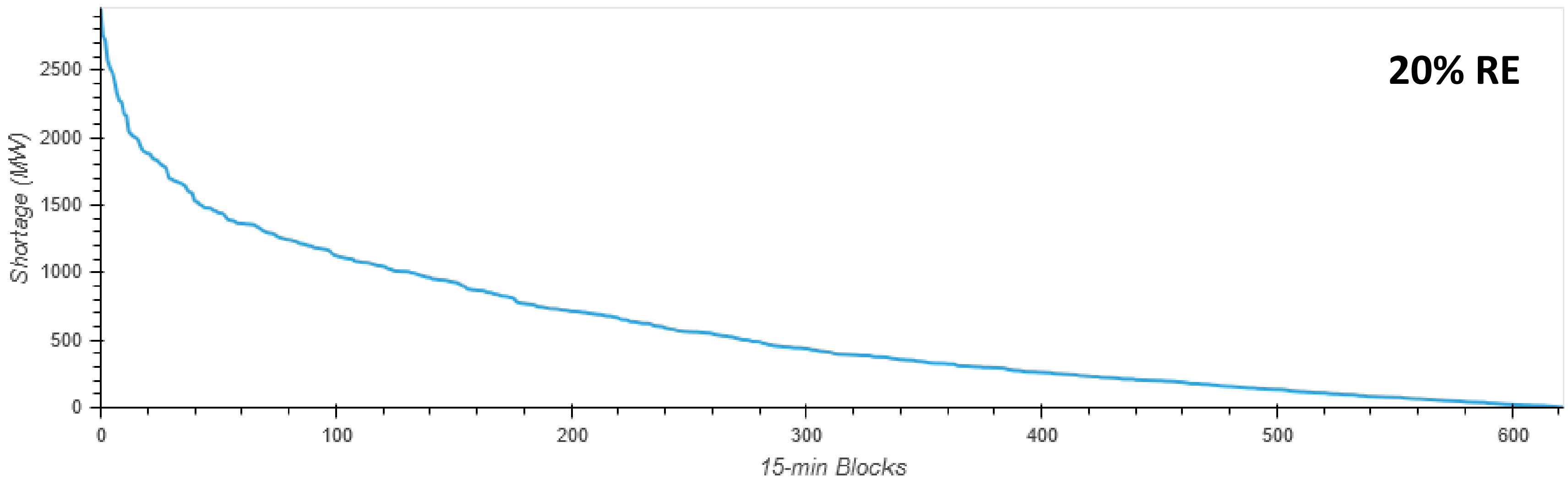
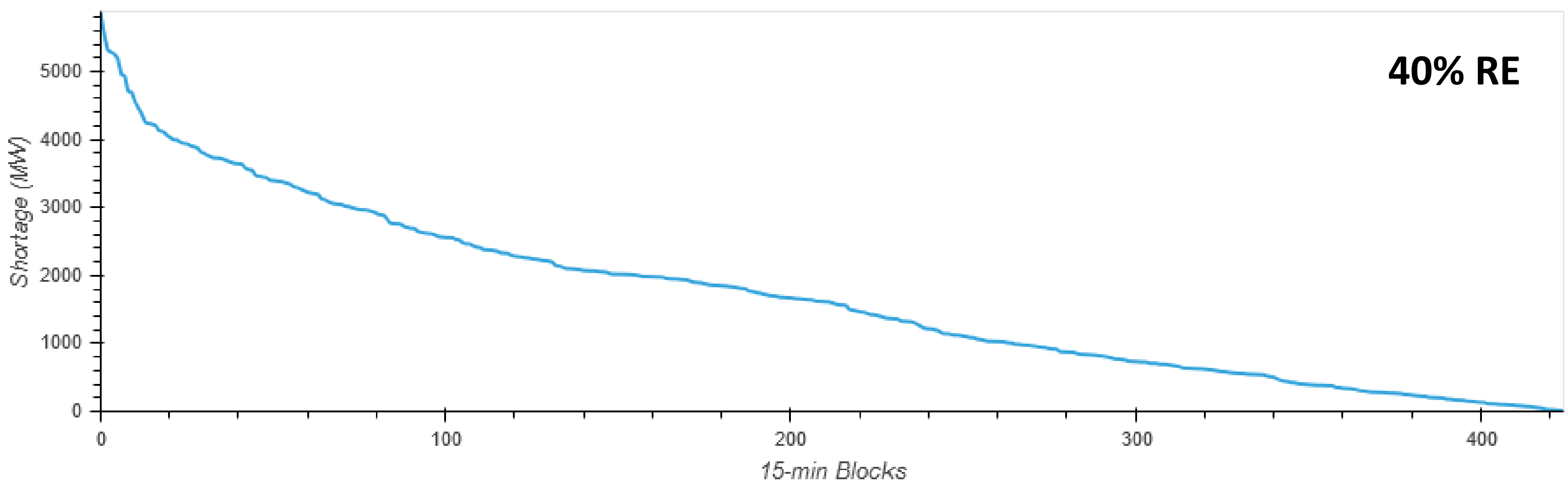
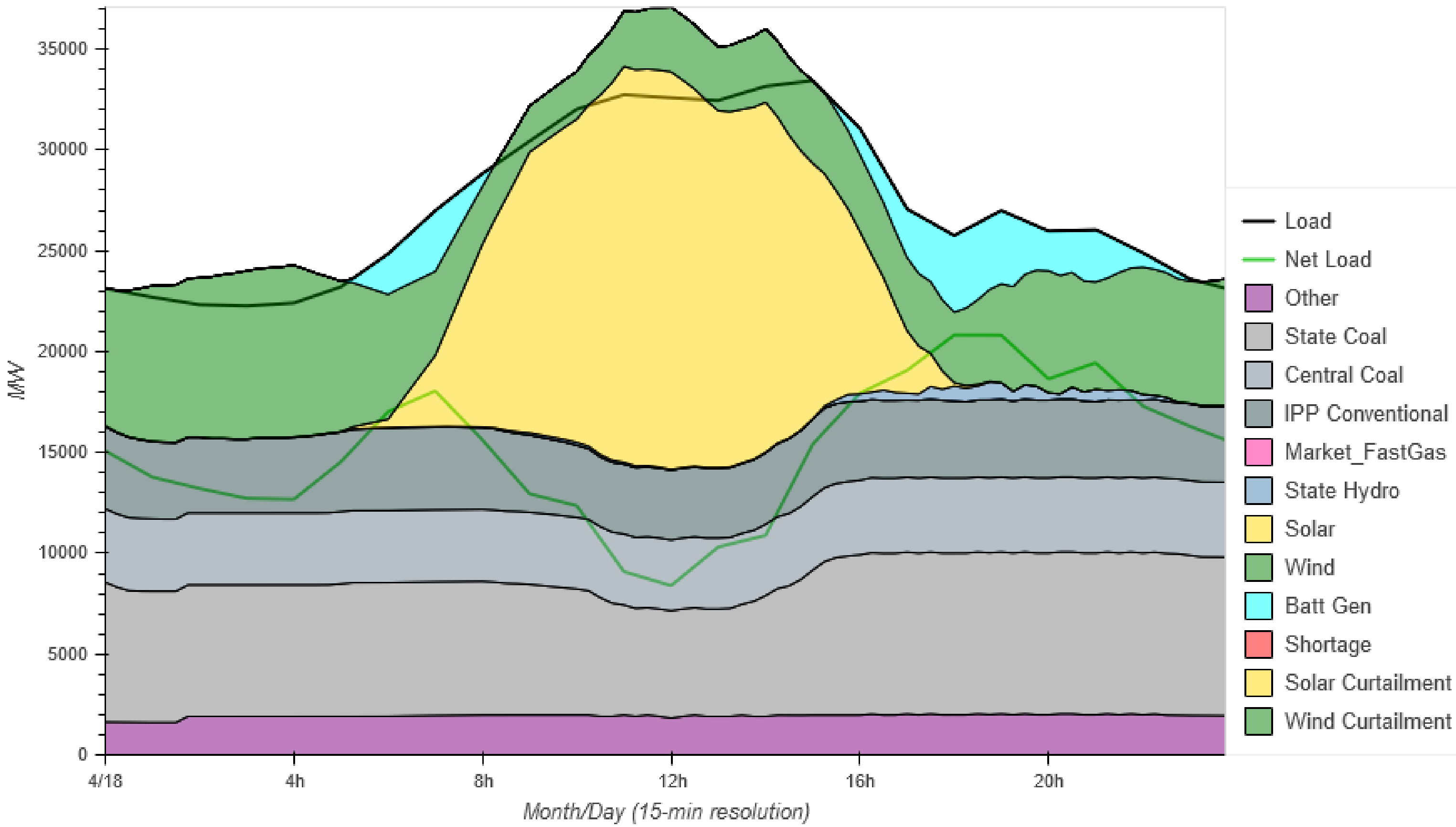
Shortage duration curve



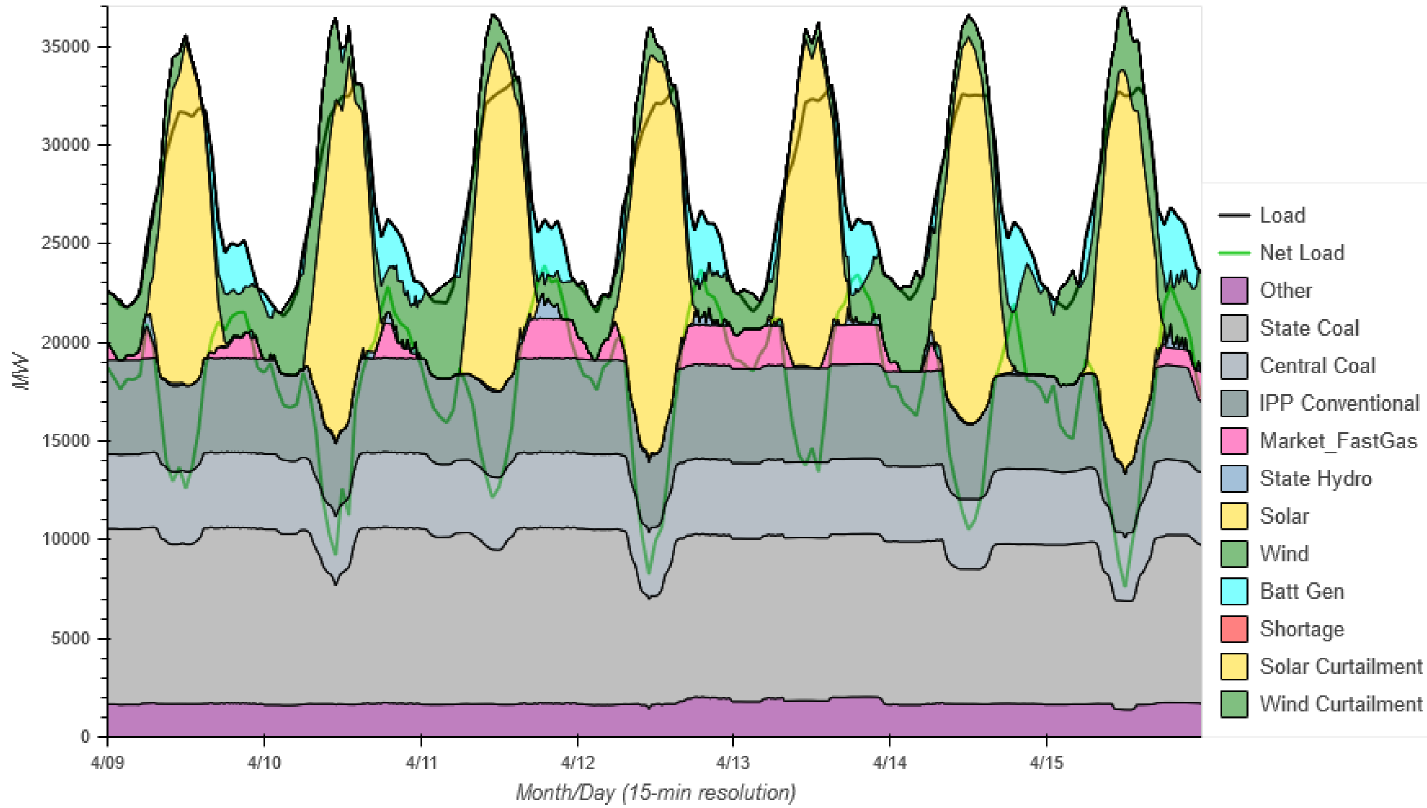


40% RE: High Load Day



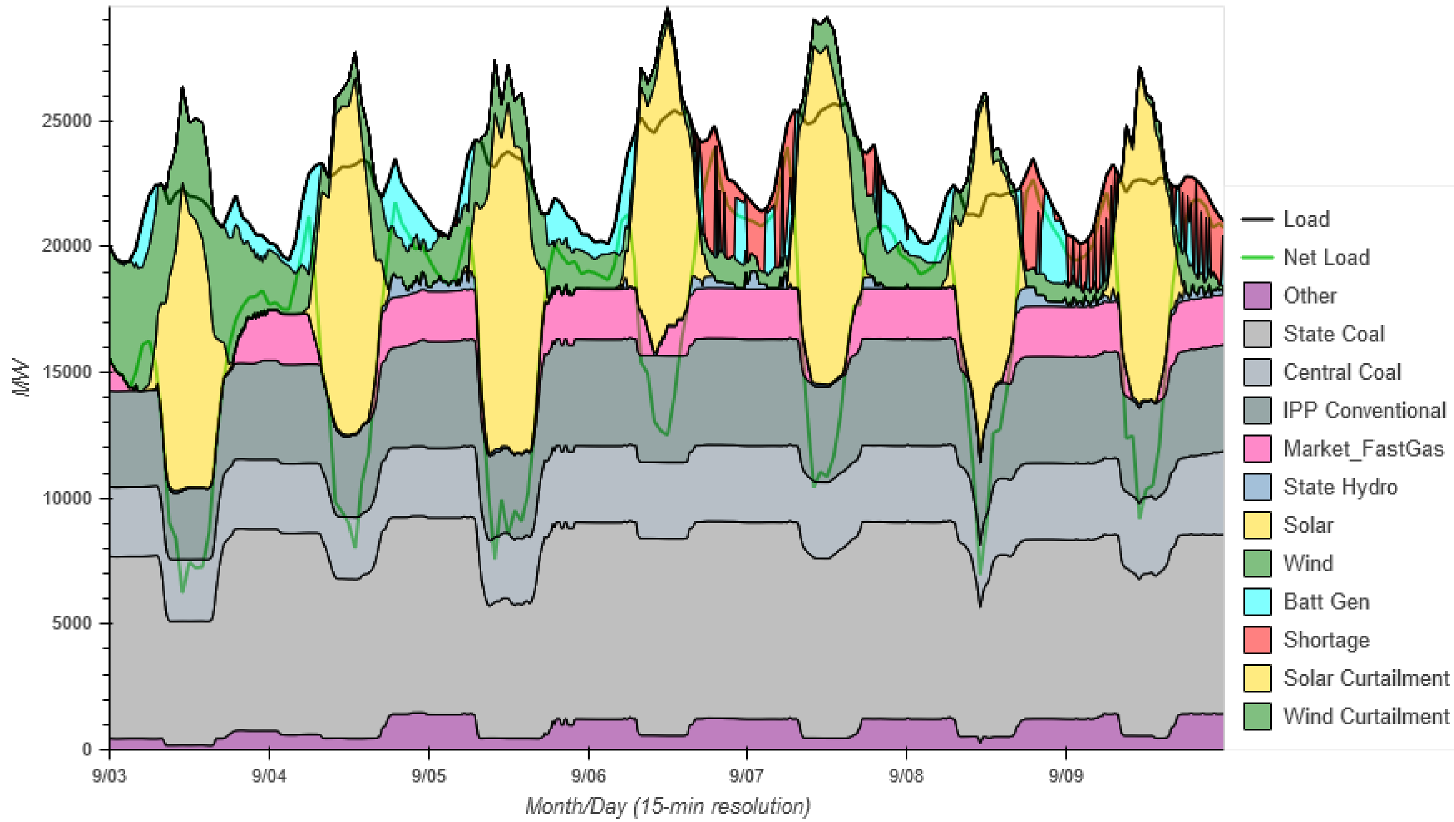
- Battery charged during the day with generation above the load line
- Battery discharged during net load peaks (early morning and late evening)

40% RE: High Load Week



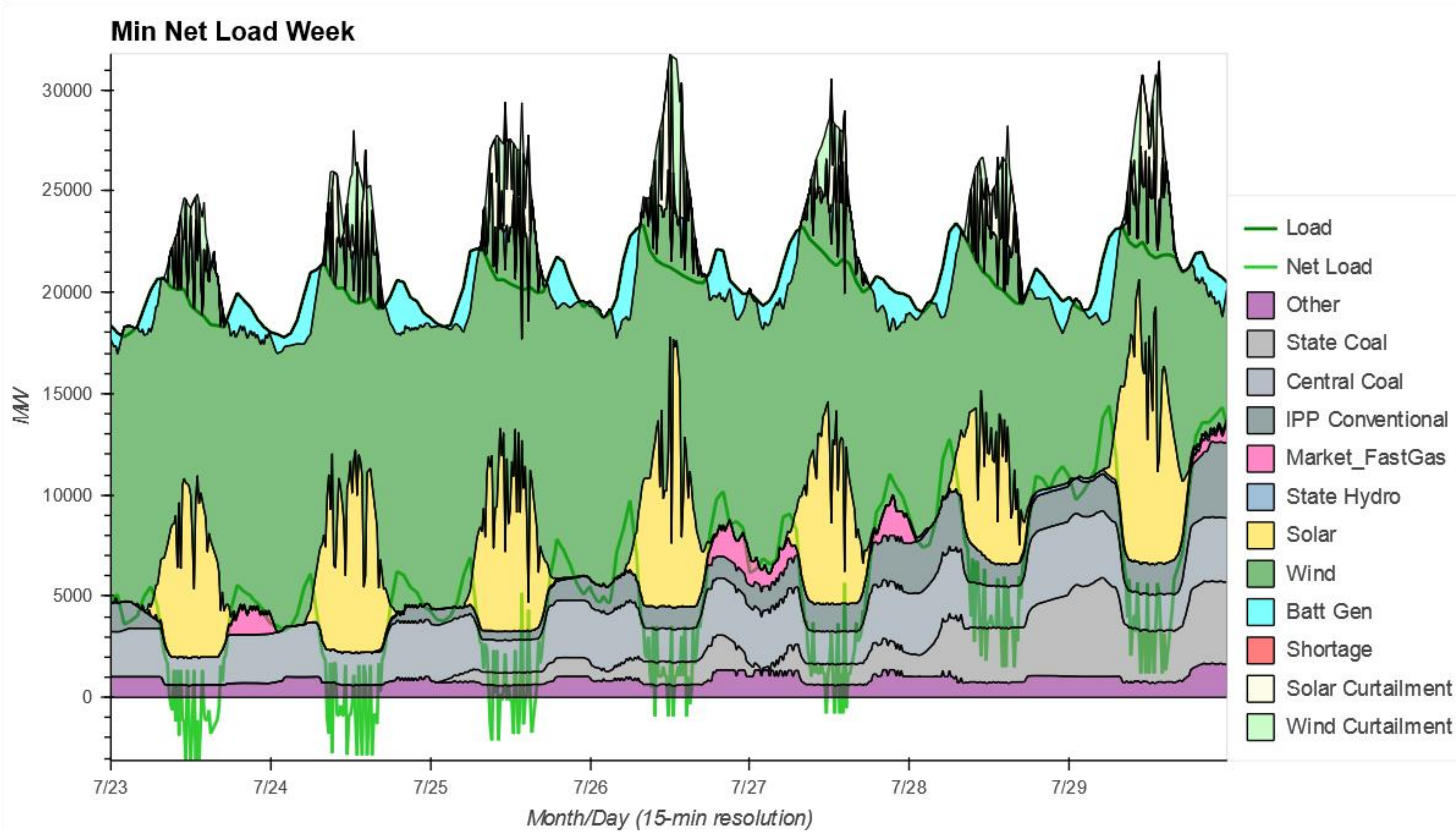
- Coal generation at ~20 GW and mostly flat, with a dip during the day
- Market/Flexible Gen procured opportunistically

40% RE: Max Shortage Week



- Significant variability in wind gen results in shortages since net load ramps are high and coal generation cannot be brought online quickly
- Market/Flexible gen is maxed out during non-solar hours throughout the week
- Perhaps some RE could be curtailed, and coal generation could be brought online instead of or in addition to Market/Flexible Gen

40% RE: Monsoon (minimum net load) week

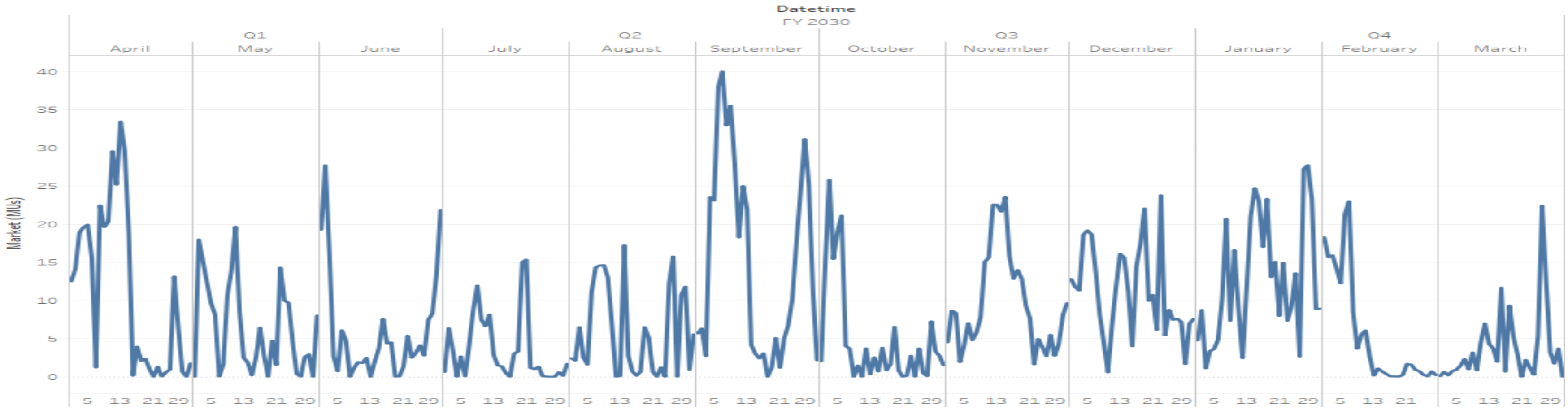


- Negative net load results in significant RE curtailment during some days

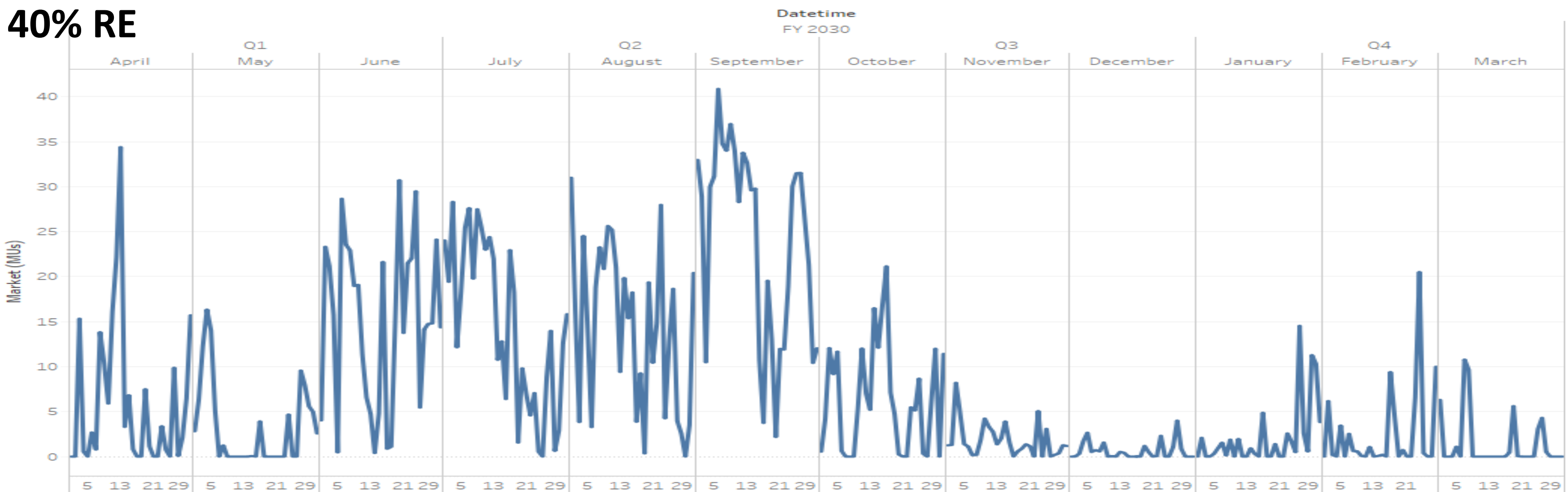
Daily Market/Flexible Gen

~1.5% of demand
~3% of total cost
~16% capacity factor

20% RE



40% RE



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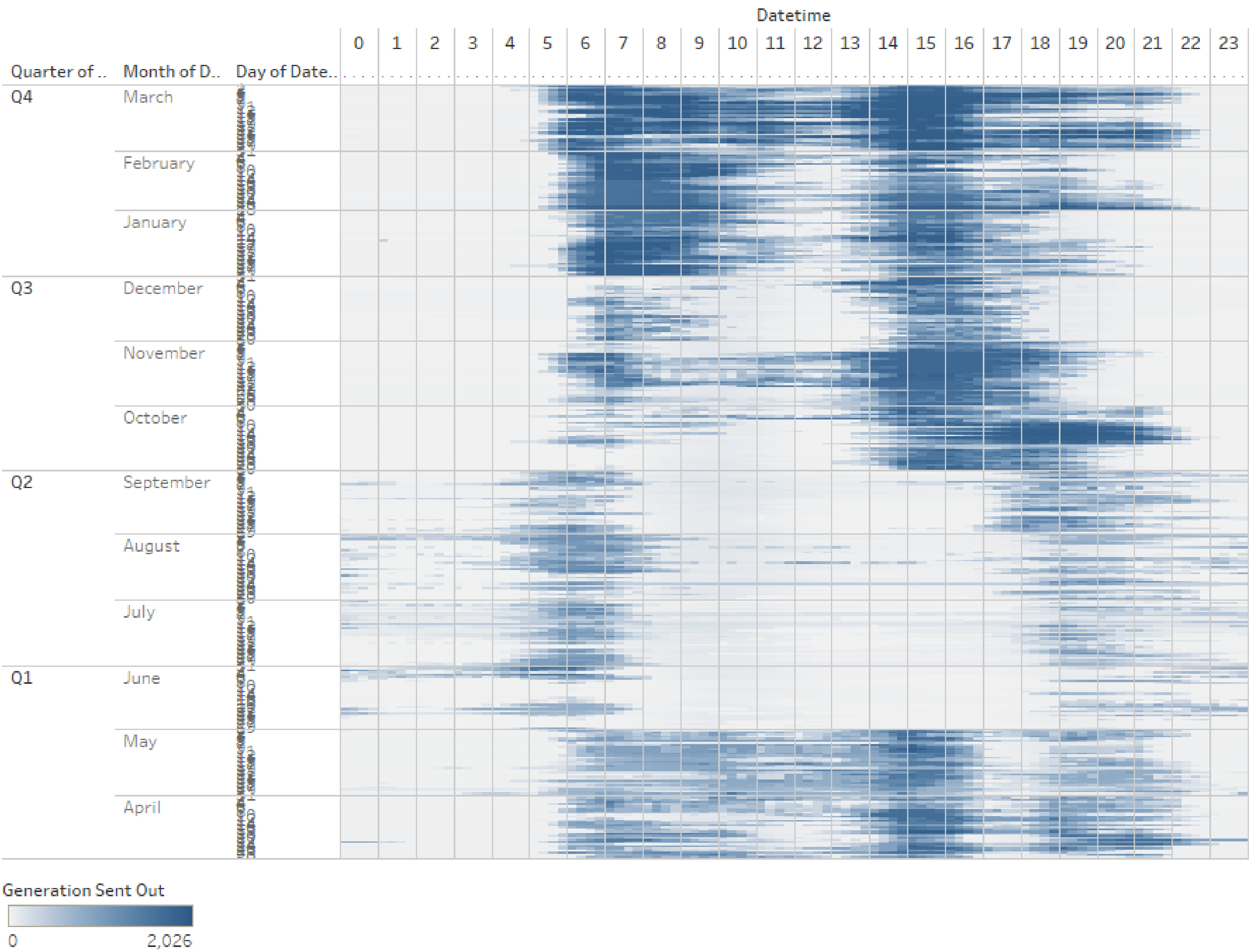
20% RE: Hydro Dispatch



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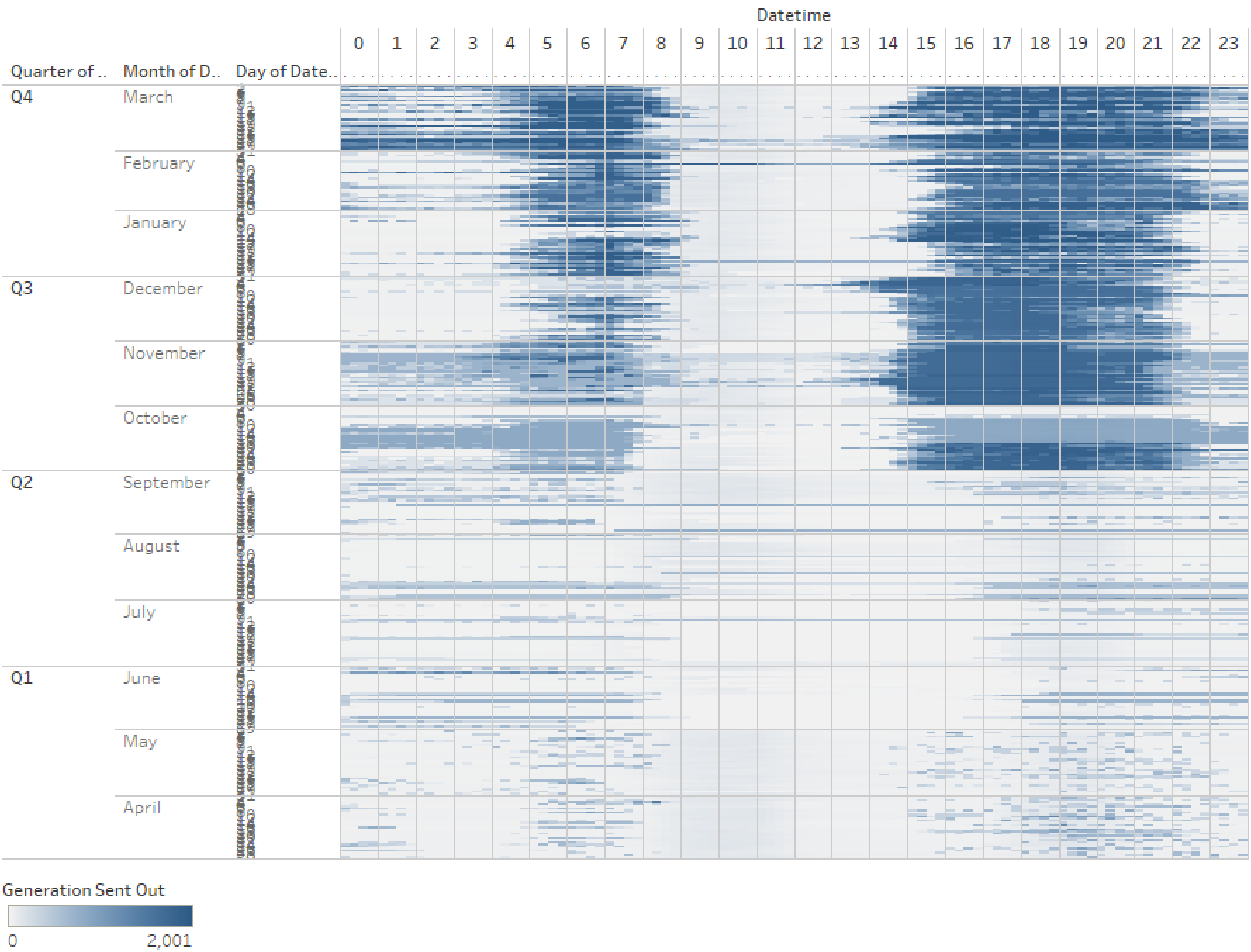
40% RE: Hydro is more of a seasonal resource



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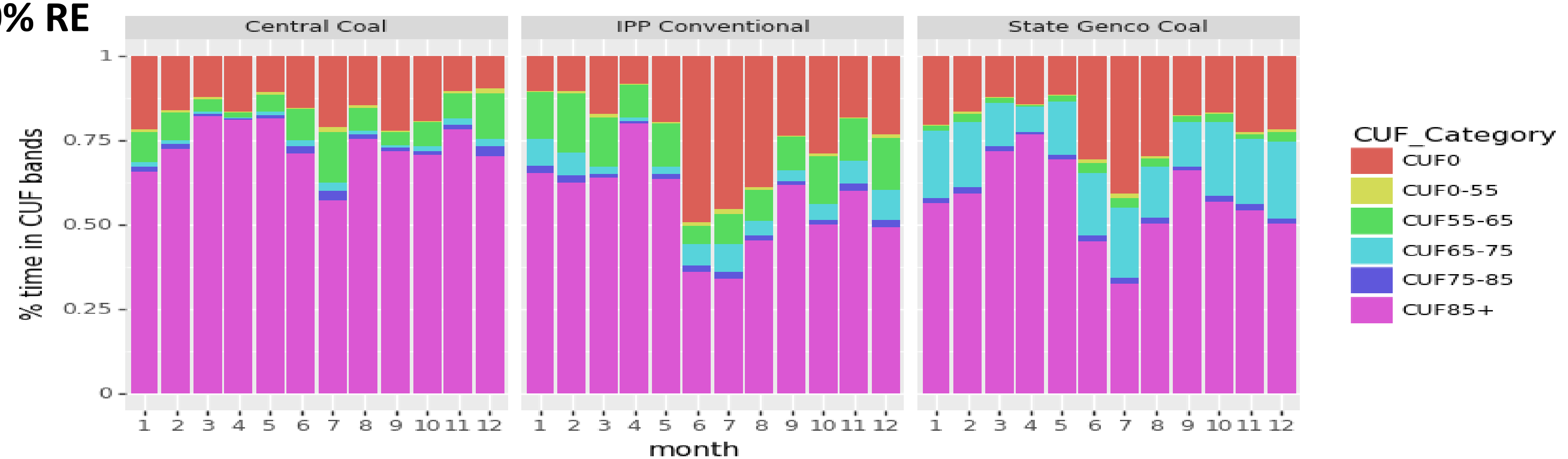
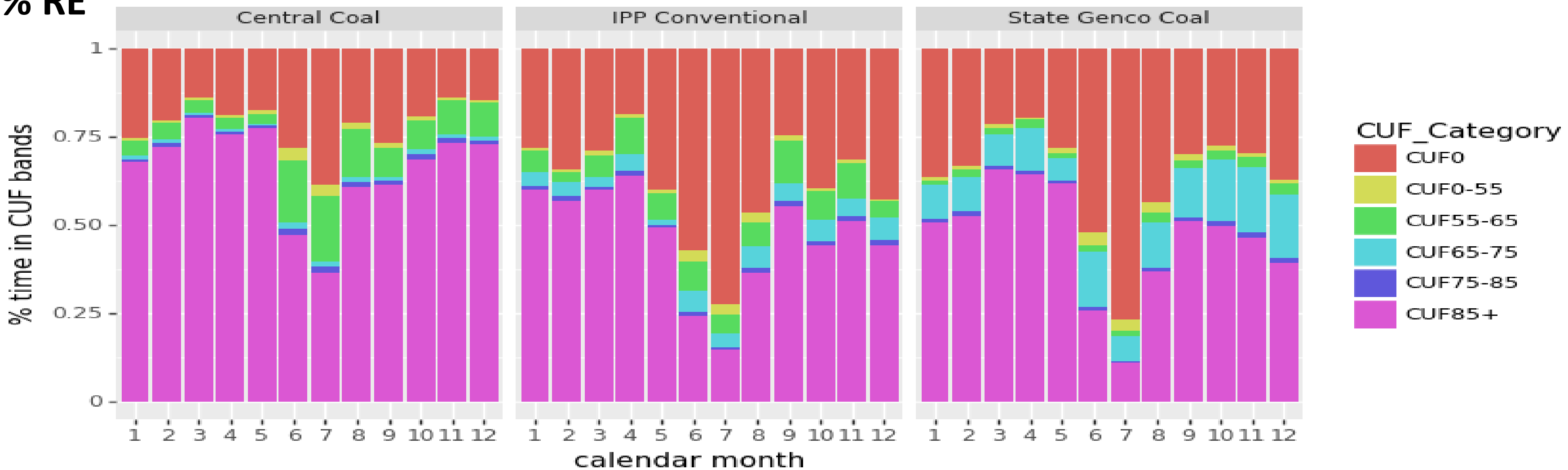
Category-wise unit loading

20% RE



40% RE



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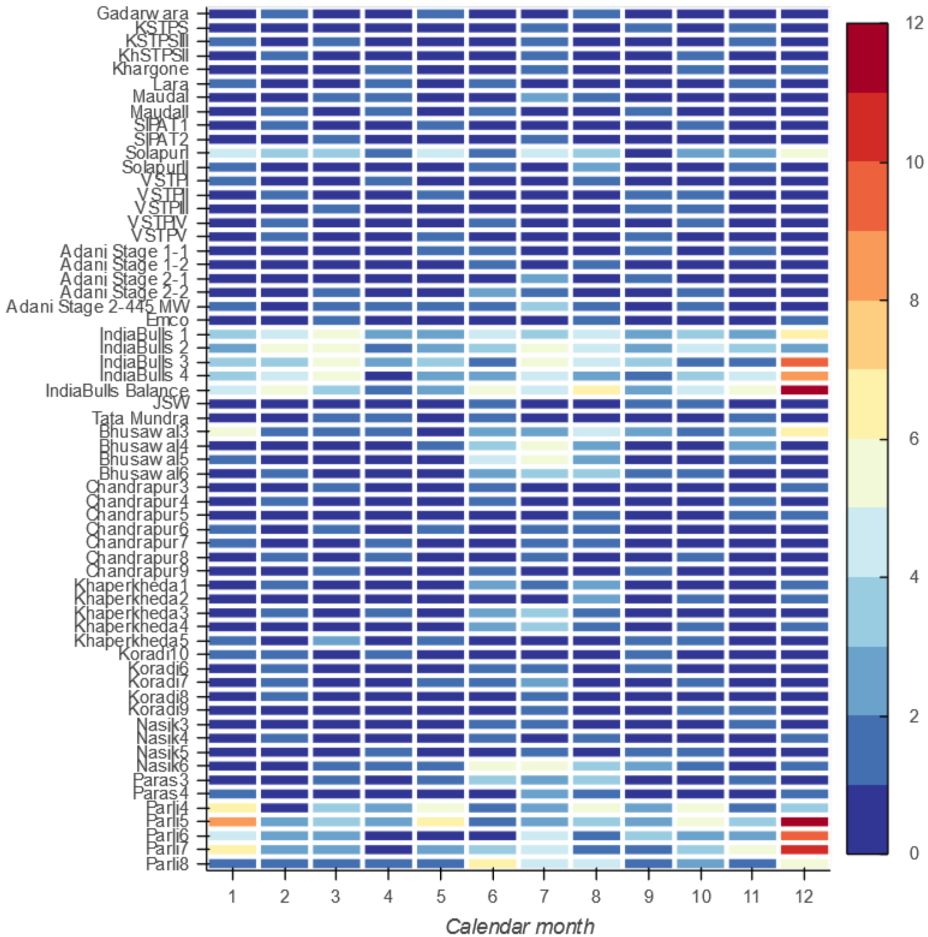
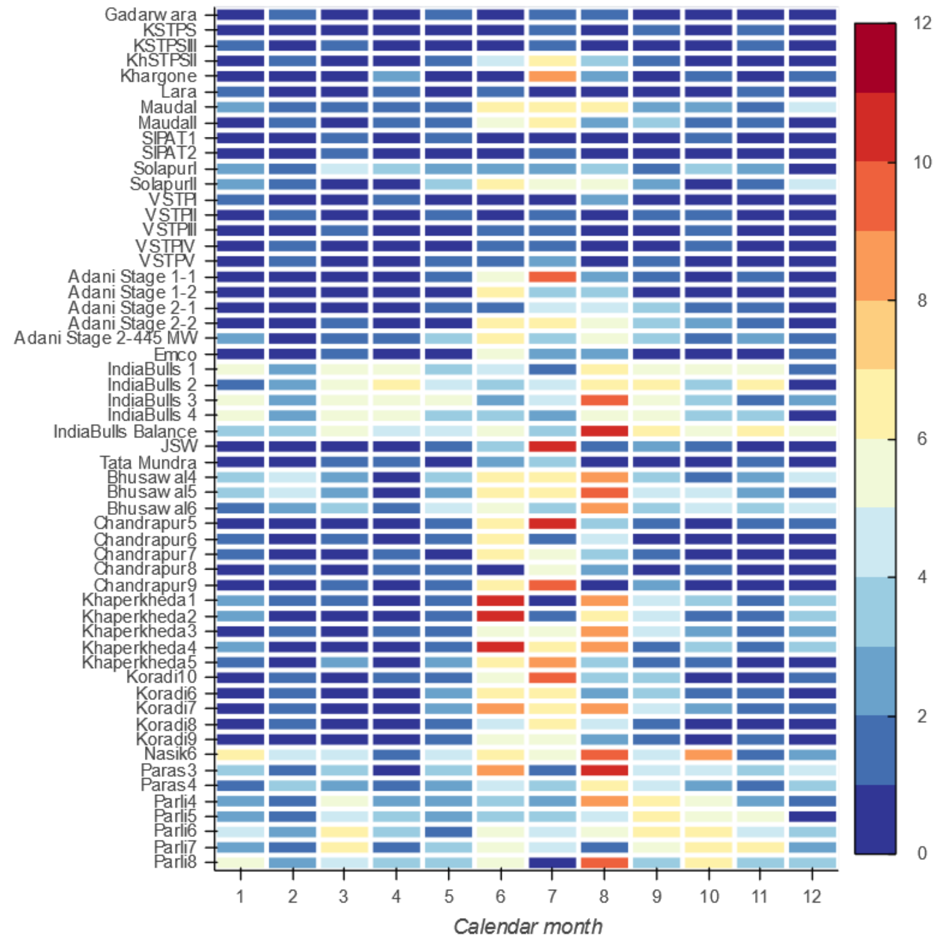
Unit starts/month

20% RE



40% RE – higher starts during monsoon



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Sensitivity Scenarios

- Start costs as per CEA report on 'Flexible Operation of Thermal power plants for integration of renewables'

- 5% increase in load during stress hours
  - 5-8am, 5-8pm
  - Stress hours from point of view of meeting demand due to high ramps in net load

- 5% growth in demand every year as opposed to 3.85%
  - 20% RE: Add 2 GW of additional coal
  - 40% RE: Add 2.5 GW of battery in addition to the RE capacity added to meet additional demand

Summary

- Summary of key parameters across scenarios

Parameter	20% RE	40% RE	40% RE	20% RE	40% RE
Demand Growth (%)	3.85%	3.85%	3.85%	5%	5%
Increased Stress			5%		
Demand (MUs)	203,939	203,939	206,510	232,751	232,751
Peak Demand (MW)	33,473	33,473	33,895	38,119	38,119
Shortage (MUs)	92	180	246	619	489
RE curtailment (MUs)	102	1351	1523	92	723
Market purchase (MUs)	2898	2790	3073	5314	5612
Coal PLF (%)	73%	63%	64%	76%	71%
Coal starts	786	1386	1445	639	1015
Total Cost (Rs/kWh)	Variation of 1-3% across scenarios				

Key Insights …. 1

- Possible to meet demand in 2030 without any 'net addition to coal fleet' and with 40 % energy contribution from RE
  - Similar reliability as coal dominant scenario
  - Operation of coal plants within technical limits (technical min, ramp up etc.)
  - MH needs to plan for RE contracted capacity of 40-45 GW by 2030 (from 12-13 GW in 2019)

Key Insights …2

- Solar feeder, day time AG load, significantly helps in solar absorption
- For reliability, necessary to procure ‘peaking’ power ~ 15 - 30% PLF
  - high cost (either low PLF or market)
- Desirable to have seasonal, short term procurement to meet seasonal high load
- Coal availability, cost and flexible operation ability important considerations in both scenarios
- Demand response measures are essential to avoid sudden shortage for even few hours a year (~ 20 – 30 hrs.)

Key Insights …. 3

- Some immediate actions / policies that could be considered as part of MYT
  - Seasonal tariffs
  - Expanding ToD regime to 5/10kW+ and adjusting peak tariff slot
  - Seasonal short term procurement
  - Peak / exigency power procurement approval
- Initiating procurement of grid scale battery storage on pilot basis
- Ensure/expand solar feeder
- Transmission planning for 40% RE scenario
- More structured and rigorous RE procurement approach (location, profile etc.). Value to the system rather than just least cost approach needs to be adopted.

Additional considerations

20% RE	40% RE
Uncertain availability – needs careful management of coal supply and unit maintenance.	Higher ramp requirements and shutdown of plants – opportunistic contracts with other states/regions
Higher costs for new capacity and uncertainty of coal cost trajectory. Lumpy investments, long gestation and high cost lock in risk.	Additional transmission costs but could also be co-located with load. Highly modular and short gestation giving more optionality; fixed price contracts.
Flexible coal operation is a requirement in this scenario too given RE and demand variability.	Battery helps in addressing diurnal shortages and absorbing economical solar/RE. Hydro becomes a more seasonal resource.
Higher risk of future stricter environmental compliance.	Much lower on water requirements in addition to local air quality and GHG benefits.

Possible future work

- Impact of part load heat rates on system operation and costs
- Additional load profiles
- Different RE generation profiles
- Regional/national balancing
- Transmission (subject to data availability)

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