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, sensitivities, 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 constraints

• 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

<table>
<thead>
<tr>
<th>Category</th>
<th>Contracted Capacity (MW) in FY18</th>
</tr>
</thead>
<tbody>
<tr>
<td>State Genco Coal</td>
<td>10,170</td>
</tr>
<tr>
<td>State Genco Gas</td>
<td>672</td>
</tr>
<tr>
<td>State Genco Hydro</td>
<td>2,352</td>
</tr>
<tr>
<td>Central Coal</td>
<td>4,511</td>
</tr>
<tr>
<td>Central Gas</td>
<td>461</td>
</tr>
<tr>
<td>Central Hydro</td>
<td>491</td>
</tr>
<tr>
<td>Central Nuclear</td>
<td>748</td>
</tr>
<tr>
<td>IPP Coal</td>
<td>5,585</td>
</tr>
<tr>
<td>Wind</td>
<td>3,641</td>
</tr>
<tr>
<td>Solar</td>
<td>987</td>
</tr>
<tr>
<td>Other NCE</td>
<td>2,242</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>31,860</strong></td>
</tr>
</tbody>
</table>
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

<table>
<thead>
<tr>
<th>Demand</th>
<th>FY18</th>
<th>FY30</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual (MUs)</td>
<td>129,605</td>
<td>203,939</td>
</tr>
<tr>
<td>Average (MW)</td>
<td>14,795</td>
<td>23,281</td>
</tr>
<tr>
<td>Peak (MW)</td>
<td>19,077</td>
<td>33,895</td>
</tr>
<tr>
<td>Trough (MW)</td>
<td>10,393</td>
<td>12,389</td>
</tr>
</tbody>
</table>
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**
- Addition of 4x660 MW coal-based capacity
- RE capacity addition to meet 20% generation through RE

<table>
<thead>
<tr>
<th>Category</th>
<th>FY18</th>
<th>20% RE in FY30</th>
<th>40% RE in FY30</th>
</tr>
</thead>
<tbody>
<tr>
<td>State Genco Coal</td>
<td>10,170</td>
<td>11,490</td>
<td>10,230</td>
</tr>
<tr>
<td>State Genco Hydro</td>
<td>2,352</td>
<td>2,352</td>
<td>2,352</td>
</tr>
<tr>
<td>Central Coal</td>
<td>4,511</td>
<td>5,117</td>
<td>5,117</td>
</tr>
<tr>
<td>IPP Coal</td>
<td>5,585</td>
<td>5,585</td>
<td>5,585</td>
</tr>
<tr>
<td>New Coal</td>
<td>2,640</td>
<td>2,640</td>
<td>-</td>
</tr>
<tr>
<td>Wind</td>
<td>3,641</td>
<td>8,524</td>
<td>15,175</td>
</tr>
<tr>
<td>Solar</td>
<td>987</td>
<td>11,781</td>
<td>26,484</td>
</tr>
<tr>
<td>Others</td>
<td>4,614</td>
<td>4,957</td>
<td>4,957</td>
</tr>
<tr>
<td>Total</td>
<td>31,860</td>
<td>52,444</td>
<td>69,900</td>
</tr>
</tbody>
</table>

**Market/Flexible Gen**  2,000  2,000

**Battery**              4,500

**40% RE**
- Considered retirement of 6x210 MW of State Genco
- Addition of 2.5 GW 6-hr and 2 GW 2-hr battery
RESULTS
Daily generation stack

20% RE

40% RE
## Key parameters – comparison

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<tr>
<th>Category</th>
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<th>40% RE</th>
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<tbody>
<tr>
<td>Annual Demand (MUs)</td>
<td>203,939</td>
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</tr>
<tr>
<td>Annual Shortage (MUs)</td>
<td>92</td>
<td>180</td>
</tr>
<tr>
<td>RE Curtailment (MUs)</td>
<td>102</td>
<td>1,350</td>
</tr>
<tr>
<td>State Genco Coal PLF</td>
<td>71%</td>
<td>60%</td>
</tr>
<tr>
<td>Central Coal PLF</td>
<td>77%</td>
<td>71%</td>
</tr>
<tr>
<td>IPP Coal PLF</td>
<td>73%</td>
<td>63%</td>
</tr>
</tbody>
</table>

### Diagram:

- **20% RE**
  - Quarterly breakdown showing energy usage.
  - Highlighted periods indicate energy surplus or deficit.

- **40% RE**
  - Similar quarterly breakdown.
  - More pronounced variations compared to 20% RE.
Shortage duration curve

20% RE

40% RE
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)
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

20% RE

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

40% RE
20% RE: Hydro Dispatch
40% RE: Hydro is more of a seasonal resource
Category-wise unit loading

20% RE

<table>
<thead>
<tr>
<th>Category</th>
<th>Central Coal</th>
<th>IPP Conventional</th>
<th>State Genco Coal</th>
</tr>
</thead>
</table>

CUF_Category
- CUF0
- CUF0-55
- CUF55-65
- CUF65-75
- CUF75-85
- CUF85+

% time in CUF bands

40% RE

<table>
<thead>
<tr>
<th>Category</th>
<th>Central Coal</th>
<th>IPP Conventional</th>
<th>State Genco Coal</th>
</tr>
</thead>
</table>

CUF_Category
- CUF0
- CUF0-55
- CUF55-65
- CUF65-75
- CUF75-85
- CUF85+
Unit starts/month

20% RE

40% RE – higher starts during monsoon
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

<table>
<thead>
<tr>
<th>Parameter</th>
<th>20% RE</th>
<th>40% RE</th>
<th>40% RE</th>
<th>20% RE</th>
<th>40% RE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Growth (%)</td>
<td>3.85%</td>
<td>3.85%</td>
<td>3.85%</td>
<td>5%</td>
<td>5%</td>
</tr>
<tr>
<td>Increased Stress</td>
<td></td>
<td></td>
<td></td>
<td>5%</td>
<td></td>
</tr>
<tr>
<td>Demand (MUs)</td>
<td>203,939</td>
<td>203,939</td>
<td>206,510</td>
<td>232,751</td>
<td>232,751</td>
</tr>
<tr>
<td>Peak Demand (MW)</td>
<td>33,473</td>
<td>33,473</td>
<td>33,895</td>
<td>38,119</td>
<td>38,119</td>
</tr>
<tr>
<td>Shortage (MUs)</td>
<td>92</td>
<td>180</td>
<td>246</td>
<td>619</td>
<td>489</td>
</tr>
<tr>
<td>RE curtailment (MUs)</td>
<td>102</td>
<td>1351</td>
<td>1523</td>
<td>92</td>
<td>723</td>
</tr>
<tr>
<td>Market purchase (MUs)</td>
<td>2898</td>
<td>2790</td>
<td>3073</td>
<td>5314</td>
<td>5612</td>
</tr>
<tr>
<td>Coal PLF (%)</td>
<td>73%</td>
<td>63%</td>
<td>64%</td>
<td>76%</td>
<td>71%</td>
</tr>
<tr>
<td>Coal starts</td>
<td>786</td>
<td>1386</td>
<td>1445</td>
<td>639</td>
<td>1015</td>
</tr>
</tbody>
</table>
| 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

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