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Centre for Energy and Environmental Markets

Impact of Operational Constraints on Generation Portfolio Planning with Renewables

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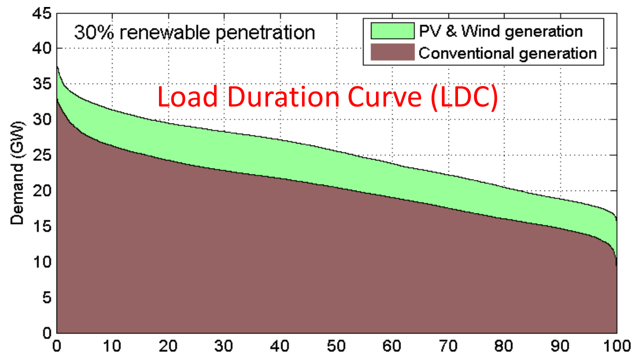
Context

- Variable renewables poses operational challenges for power systems and thermal generating plants – *frequent cycling.*
- Long-term (LT) generation planning uses LDC – simple but ignore short-term (ST) operational aspects.
  - *Can't capture the ability of plants in responding to changes in demand.*

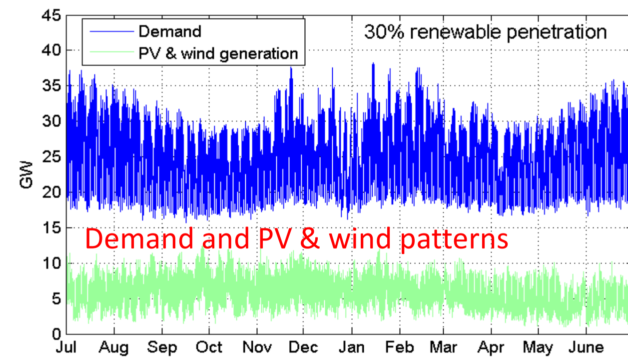
LT Generation planning
- Long planning horizon (5 years+)
- Ignore operating constraints & chronological demand variability

ST electricity industry operation
- Short timeframe (min. to hours)
- Subject to inter-temporal generating unit constraints

Min. Gen, Ramp rates, Startup time



Chronological demand is rearranged in order of magnitude



Optimal portfolios obtained from LT models may not be viable (operationally and economically)

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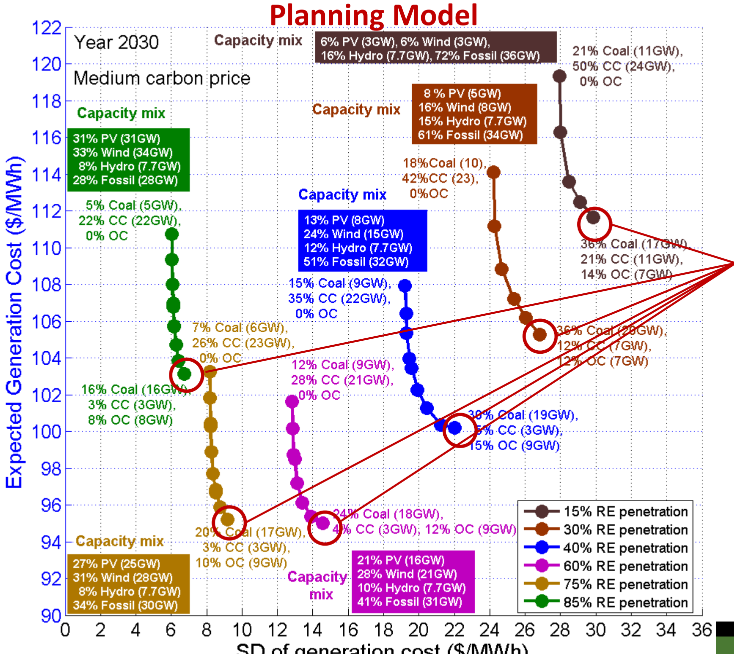
Objectives and methodology

- Assess the impact of generator operational characteristics on future generation portfolios with high renewables obtained under LT planning models - *Technical and cost impact.*

Take the optimal portfolios from ***MC-ELECT*** and input into ***PLEXOS*** → Add plant constraints (min. gen., ramp rates, startup costs, min. synchronous) → Using **PLEXOS** to solve hourly constrained dispatch → Compare the costs to assess the impact of constraints

Optimal generation portfolios from LT Portfolio Planning Model



- Using a portfolio planning model, **MC-ELECT**, to obtain the least cost portfolios for different renewables.
  - *Uses LDC which ignores ST constraints*
- Using **PLEXOS** to solve detailed constrained dispatch - *Constraints include min. generation, ramp rates, min. synchronous levels, startup costs.*

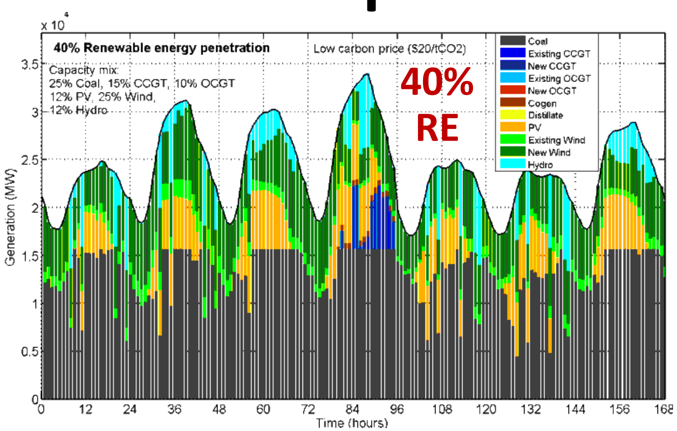
Australian NEM Case Study in 2030

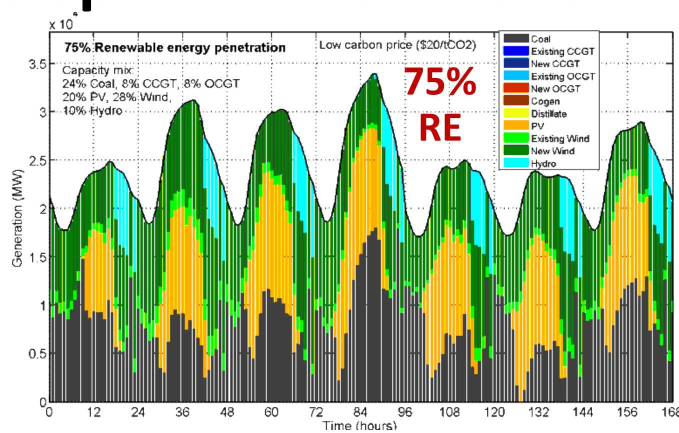
RE penetration scenario in 2030

15% RE	30% RE	40% RE	60% RE	75% RE	85% RE

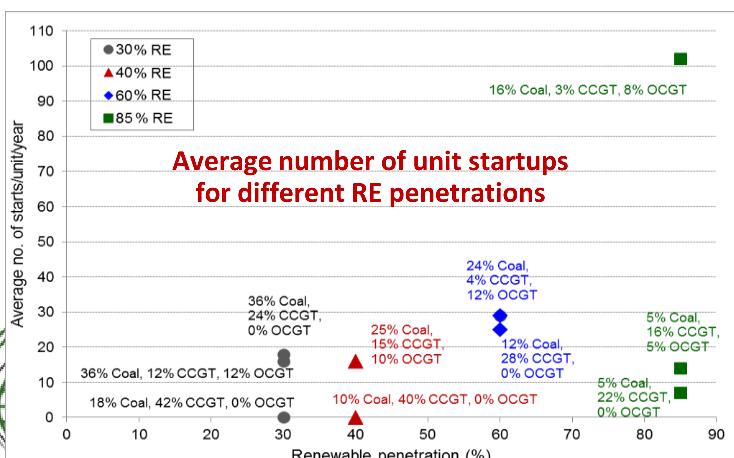
- Six RE scenarios for 2030.
- Eight generation options.

- **Detailed operational dispatch – Number of unit starts/stops**





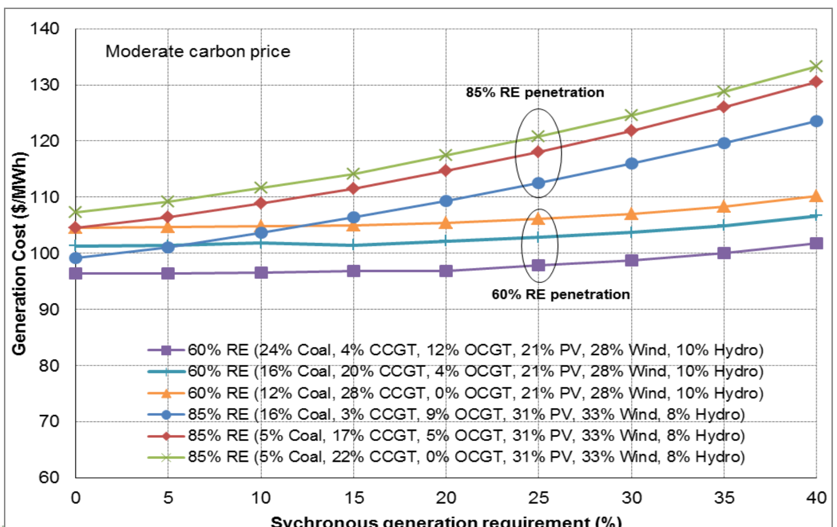
Thermal plants are required to cycle more often with higher RE penetrations



– No. of starts/stops depend on RE penetration levels and technology mix.
– Highest no. of starts for CCGT is 230/unit/year – within design limits.
– No. of coal starts seem technically viable.

Australian NEM Case Study in 2030

- **Impact of min. generation and ramp rate limits**
  - Min. generation and ramp rate constraints only slightly increase the overall costs of portfolios obtained under the LT planning.
  - The largest cost increase in any portfolio is 2%.
  - All portfolios can meet the maximum ramps required.
- **Impact of minimum synchronous generation requirement**



  - Synchronous requirements impose significant additional costs at high RE penetrations (7% increase).
  - Negligible impact at low RE.
  - Costs associated with synchronous requirements increase with higher carbon prices.

Conclusions

- Technical and cost impacts due to the inclusion of minimum generation and ramp rate constraints seem moderate even at high RE penetrations.
- Frequent cycling for coal and CCGT as RE penetration increases, but generally still within technical limits.
- The minimum synchronous requirements can have significant cost impact.
- The impacts also depend on carbon price and technology mix in the portfolio.
- Future work will explore issues at finer dispatch time intervals.

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