California’s Rolling Blackouts and Near Blackouts in August and September 2020

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What Happened in August and September in California?

• Heat wave in California and nearby states in the West mid-August to early September
  • Heat waves not atypical for this time of year but this one was extreme

• As a result of the heat wave electricity demand increased significantly in California and across the West in mid-August and early September (and again October 1-3)
  • Up to 47,000 MW peak demand on August 14-19 and September 5,6,7
  • Previous peak 50,000 MW in 2006 and 2017 without blackouts
  • But VRE, especially solar, generation has increased a lot as 10,000MW of gas capacity retired in the last few years
  • Attributes of “net demand” (customer demand seen by ISO minus wind + solar) are more and more relevant in high and growing VRE systems as in CAISO --- further complicated by BTM PV
  • Responding effectively to variations in net demand are more challenging with very high VRE penetration
  • CAISO has significant reliance on imports from outside but heat wave across the West reduced availability of import supplies
    • CAISO import/export rules are complicated
    • Western Balancing Market
  • California has a complicated “resource adequacy” process driven by the CPUC rather than the ISO
Actual and Near Rolling Blackouts

• Actual rolling blackouts only on August 14 and 15 and threatened rolling blackouts on August 17-19 and September 5-7, 2020
  • First rolling blackouts in California since 2001
  • August 14 OK solar generation day for the season (10 GW peak vs. 12 GW on good days in June/July), but a bit ragged, and relatively poor wind day
  • August 14 rolling blackouts 1000 MW for 2-3 hours ~ 6:30 to 8:30 PM
  • August 15 poor very ragged solar day and better wind day
  • But August 15 had sudden dip and then fast recovery in wind generation (~ 1200 MW), derating of NW transmission, loss of 470 MW fossil plant during evening net peak demand period
  • August 15 rolling blackouts for only about 20 minutes starting at 6:30 PM
  • August 18 OK but very ragged solar day and better wind day for season. Formal and informal demand response. No blackouts.
  • September 6 (4,000 MW generation deficiency forecast) Good solar and wind day for season. Formal and informal demand response. No blackouts
What Happened in August and September in California?

• The system was or was expected to be very stressed late afternoon/early evening on several days in August and September.

• Formal demand response programs, voluntary conservation, and emergency actions by the ISO appear to have played important roles in keeping rolling blackouts from being implemented on some of the Stage 2/3 Emergency days in mid-August and early September.

• Market Monitoring Committee found that contribution of formal demand response programs appears to have been less than anticipated.

• Market Monitoring Committee (MMC) has concluded that market manipulation (withholding) was not a contributing factor.

• MMC has also concluded that wind and solar underperformed their RA values as gas capacity was derated by 3% due to heat.

• MMC concluded that virtual demand bidding led to underestimation of demand.

• Combination of exports and imports (at the same time) with different RA credits complicated operations and created some confusion about imports available.

• The fires led to de-rating of one line from the NW at least on August 15 and a reduction in solar radiation a bit later.
Net Demand August 14, 2020

Avg. ramp
~8,357MW in 3 hrs.
Net Demand August 15, 2020

Avg. ramp
~8,547MW in 3 hrs.
CAISO Solar Generation on August 14 and August 15, 2020

Generated with NRGStream Trader 8
CAISO WIND GENERATION ON AUGUST 14 and 15, 2020

Generated with NRGStream Trader 8
Smoke Effects on Solar Generation

Real Time Prices SP15

Generated with NRGStream Trader 8
Day-ahead and Real Time Prices August 14, 2020

Generated with NRGStream Trader 8
Conclusions and Responses

• Despite all of the attention and hand wringing, actual blackouts during the heat wave were relatively small (1000 MW) and of short duration
  • Extreme heat wave situation but capacity planning was based on 1 in 2 year peak demand and 15% administrative reserve margin
  • Not like 2001 when there were 38 days of rolling blackouts
  • Not like the pre-emptive “Public Safety Power Shutoff” and wild-fire-related events in 2017, 2018 and especially 2019 when millions of customers had their power cut often for several days to reduce the risk of fires
  • Not like outages after severe hurricanes in the East which can last days
  • But perhaps it’s a warning about the challenges for market-based systems which are heavily reliant on intermittent generation

• The ISO generally responded reasonably well to the situation
  • Perhaps responded too slowly on August 14
  • ISO should have been able to handle the sudden dip in wind generation on August 15 with operating reserves but recovered quickly
  • Derating of gas plants due to heat should have been expected
  • Actual capacity value for VRE is more uncertain than for dispatchable generation
  • Import/Export interactions during tight supply situations need to be sorted out
Conclusions and Responses

- Responses to calls for voluntary conservation and activation of formal demand response program appear to have averted more blackouts though formal demand response underperformed
  - Demand response will become more and more important in high-VRE/EV systems but there are limits to the effects of calls for voluntary conservation
  - Advanced metering technology is not being used effectively --- opportunities to integrate BTM PV, storage and EV in demand response programs and wholesale markets
  - Need to better link wholesale market prices with retail prices, though TOU tariff changes are a step in the right direction

- High VRE system require new approaches to “resource adequacy” which reflect variability of supplies from intermittent generation
  - The utilities in California face a complicated regulatory environment
    - CPUC, CEC, ISO, FERC
  - California has neither a centralized capacity requirement/capacity market system nor an ORDC system as in ERCOT
    - Costs of LDC contracts to meet resource adequacy criteria are not reflected in wholesale market prices
  - Need more fast flexible resources (generation and/or storage) to meet late day ramp and variations in wind and solar
  - Too much flexible gas capacity exited before storage and flexible replacement capacity entered
### Table ES2. Recommended ELCC Values for 2026

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<thead>
<tr>
<th>Region</th>
<th>BTM PV</th>
<th>Fixed PV</th>
<th>Tracking PV</th>
<th>Tracking PV Hybrid</th>
<th>Wind</th>
<th>Wind Hybrid</th>
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<tr>
<td>PGE</td>
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<td>2.1%</td>
<td>3.4%</td>
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<td>SCE/SDGE</td>
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<td>AZ APS</td>
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<tr>
<td>NM EPE</td>
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<td>CAISO</td>
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<td>39.4%</td>
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<tr>
<td>Average</td>
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<td>2.3%</td>
<td>96.8%</td>
<td>26.0%</td>
<td>58.0%</td>
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</table>

CPUC Advice Letters 4243-E, 3560-E, 5868-E, July 21, 2020; See also CPUC Decision 19-09-043, September 26, 2019
Conclusions and Responses

• The $1000/MWh price cap in CAISO is too low and rises too slowly as generation deficiency approaches
  • FERC Order 831 allows for higher “offer” caps but is based on nothing an economist would recognize
  • Scarcity pricing mechanism integrated with demand response programs and retail rates should be designed and implemented

• Too many ISO emergency actions are “out of market” and are not properly reflected in wholesale market prices
  • Reduces investment incentives and increases generation retirements for plants that rely entirely on the wholesale market for revenues