Integrating generation capacity expansion planning and resource adequacy

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ELECTRICAL & COMPUTER ENGINEERING

Generation capacity expansion planning

- How much generation capacity should we build?
- What type of generation capacity should we build?
- How much of each type?
- Long-term planning optimization problem
- Objective: minimize total cost over the planning horizon (e.g., 30 years)

Naïve mathematical formulation – Objective

Total cost: sum of investment cost and operating cost

$$\min_{n,p} \left\{ \underbrace{\sum_{g \in G} n_g P_g C_g^c}_{\text{Investment cost}} + \underbrace{\sum_{g \in G, t \in T} p_{gt} C_g^o}_{\text{Operating cost}} \right\}$$

G: set of available generation types

n_g: number of units of type g

P_g: MW capacity of a unit of type g

C_g^c: Cost per MW of a unit of type g

T: set of time periods of planning horizon

p_{gt}: production of unit g at time t

C_g^o: Cost per MWh of producing with unit g

Naïve mathematical formulation – Constraints

$n_g \geq 0 \; \forall g \in G$

$0 \leq p_{gt} \leq n_g P_g a_{gt} \quad \forall g \in G, \; t \in T$

a_{gt}: fraction of generators of type g available at t

- 100% for thermal units or derated based on average historical reliability
- Time varying for wind or solar generation

Load/generation balance:

$$\sum_{g \in G} p_{gt} = L_t \quad \forall t \in T$$

L_t: Load at time t

$$\sum_{g \in G} n_g P_g \geq L_{max}$$

L_{max}: Maximum load over planning horizon

Dealing with uncertainty

- Failures of large generating units
- Variability of renewable generation
- Error in load forecast

→ Risk not having enough generation capacity

- Need extra generation capacity to deal with unexpected events

→ Must ensure **resource adequacy**

- Traditional approach: add a planning reserve margin (PRM)

Basic planning reserve margin constraint

$$\sum_{g \in G} n_g \, P_g \geq L_{max} \quad \Rightarrow \quad \sum_{g \in G} n_g P_g \geq L_{max}(1 + PRM)$$

PRM: Planning Reserve Margin

Assumes that the full capacity of the generating units is always available

Must be improved because this is not realistic

Modified planning reserve margin constraint

$$\sum_{g \in G} n_g \; P_g \; CC_g \geq L_{max}(1 + PRM)$$

CC_g: Capacity Credit for units of type g

Conventional generating units: CC_g = average availability of units of type g

Renewable generating units: CC_g =? (to be discussed later)

PRM as a proxy for resource adequacy

$$\sum_{g \in G} n_g \, P_g \, CC_g \geq L_{max}(1 + \color{red}{PRM})$$

If PRM is sufficiently large, there should be no adequacy issue

However,

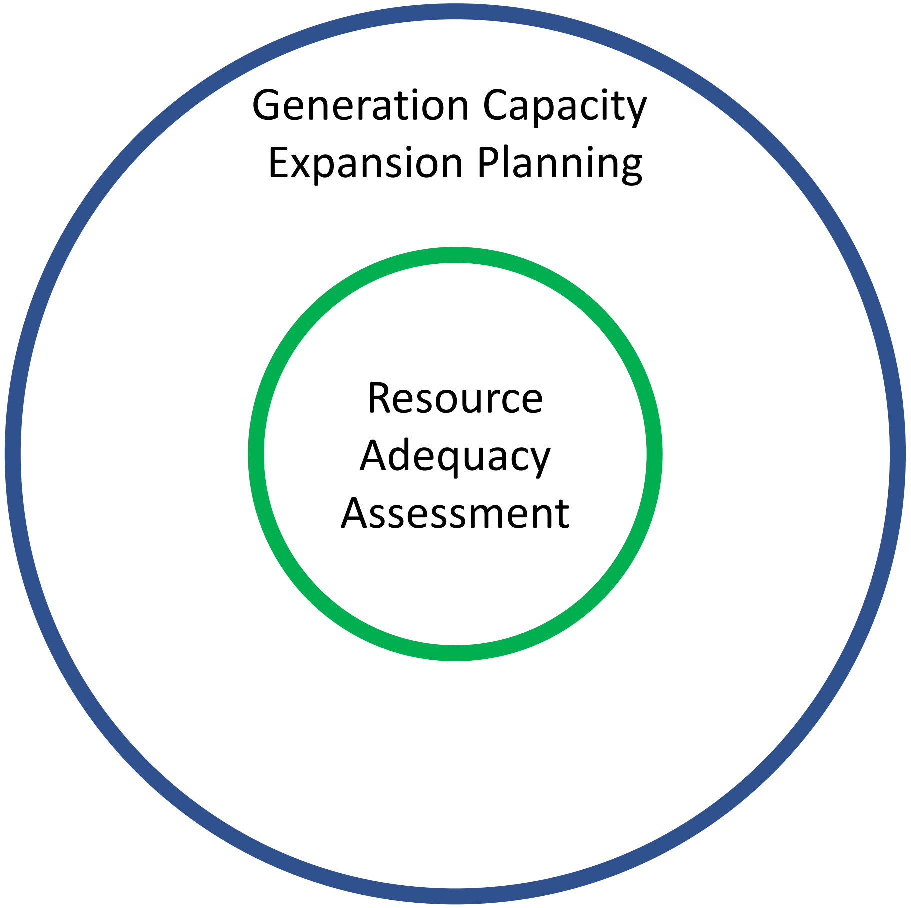
- What is the optimal PRM?
  - PRM too large → unnecessary investments
  - PRM too small → risk of inadequacy
- Do average capacity credits properly reflect uncertainty?
- What if the availability of generating units varies over time?

→ Need a more accurate representation of resource adequacy

A closer look at resource adequacy

- How often will random events require load shedding?
- Cannot guarantee that it will never happen
- Use probabilistic metrics:
  - LOLP – Loss Of Load Probability
  - EUE – Expected Unserved Energy
  - NEUE – Normalized Expected Unserved Energy
- Calculate these metrics for generation expansion plans
- Compare them against minimum acceptable levels
- Obtaining accurate probabilistic metrics requires enough representative samples!

Ideally…



- Integrate resource adequacy assessment in the generation capacity expansion planning
- Carry out a probabilistic adequacy assessment of the capacity expansion plans as part of the optimization
- Focus first on failures of large conventional generators
- Two approaches
  - Monte Carlo sampling
  - Normal approximation

Monte Carlo sampling

- Explicitly model each unit j of class g
- Generate a set of scenarios s of random outages for each unit
- Scenario-based optimization:

$$\min_{n,p}\left\{\underbrace{\sum_{g,j} b_{jg} P_g C_g^c}_{\text{Investment cost}} + \underbrace{\frac{1}{|S|}\sum_{g,j,s,t} p_{gjst} C_g^o}_{\text{Operating cost}}\right\}$$

- b_{jg}: decision to build unit j of class g
- p_{gjst}: dispatch decision for unit j under scenario s at time t

Monte Carlo sampling

- Advantage:
  - Compatible with modeling storage and transmission constraints

- Disadvantage:
  - Good accuracy requires a large number of samples

→ Only practical for a small system e.g., an island system.

Normal approximation

Number of available units of type g follows a binomial distribution: $B(n_g, a_g)$

n_g: number of units of type g a_g: availability of units of type g

Approximate this binomial distribution by a normal distribution: $N(\mu(n); \sigma^2(n))$

Probability of system adequacy at time t: $p_t = \Phi\left(\frac{\mu(n) - L_t}{\sigma(n)}\right)$

Φ: Standard normal distribution L_t: Load at time t

Add the following constraint to the capacity expansion optimization:

$$\mu(n) - \Phi^{-1}\,(1 - LOLP_{max})\sigma(n) \geq L_t$$

$LOLP_{max}$: Maximum acceptable loss of load probability

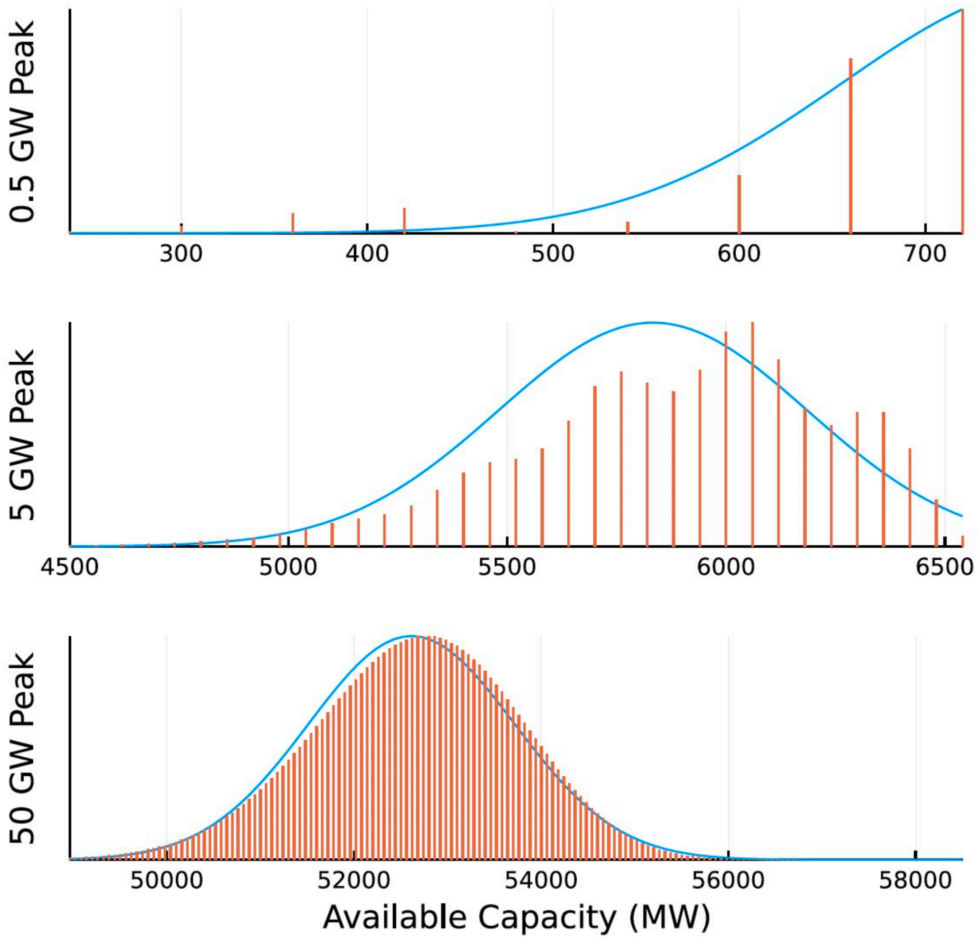
Requires an approximate convex relaxation to incorporate into optimization

Normal approximation

- Advantage:
  - Computationally much more efficient than Monte Carlo Sampling

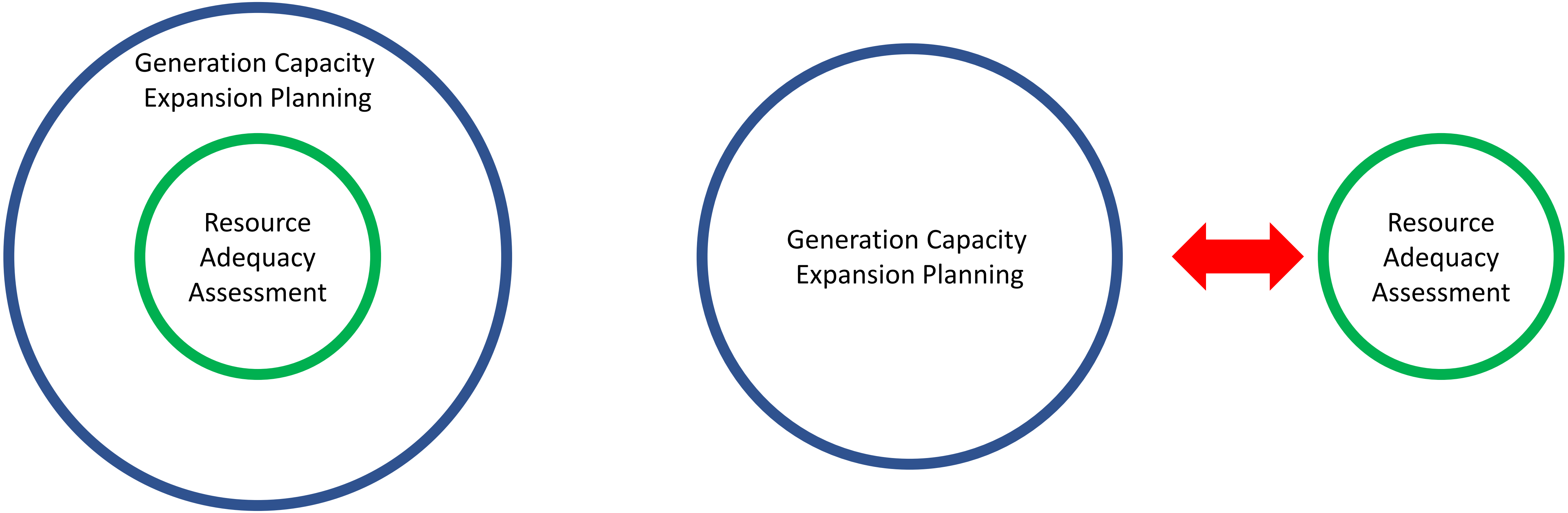
- Disadvantages:
  - Normal approximation requires many similar units of each type
    - Valid only for large systems
  - Incompatible with intertemporal and interregional constraints

Validity of the normal approximation



Distribution of total available generation capacity (rounded to the nearest full unit) for three system sizes

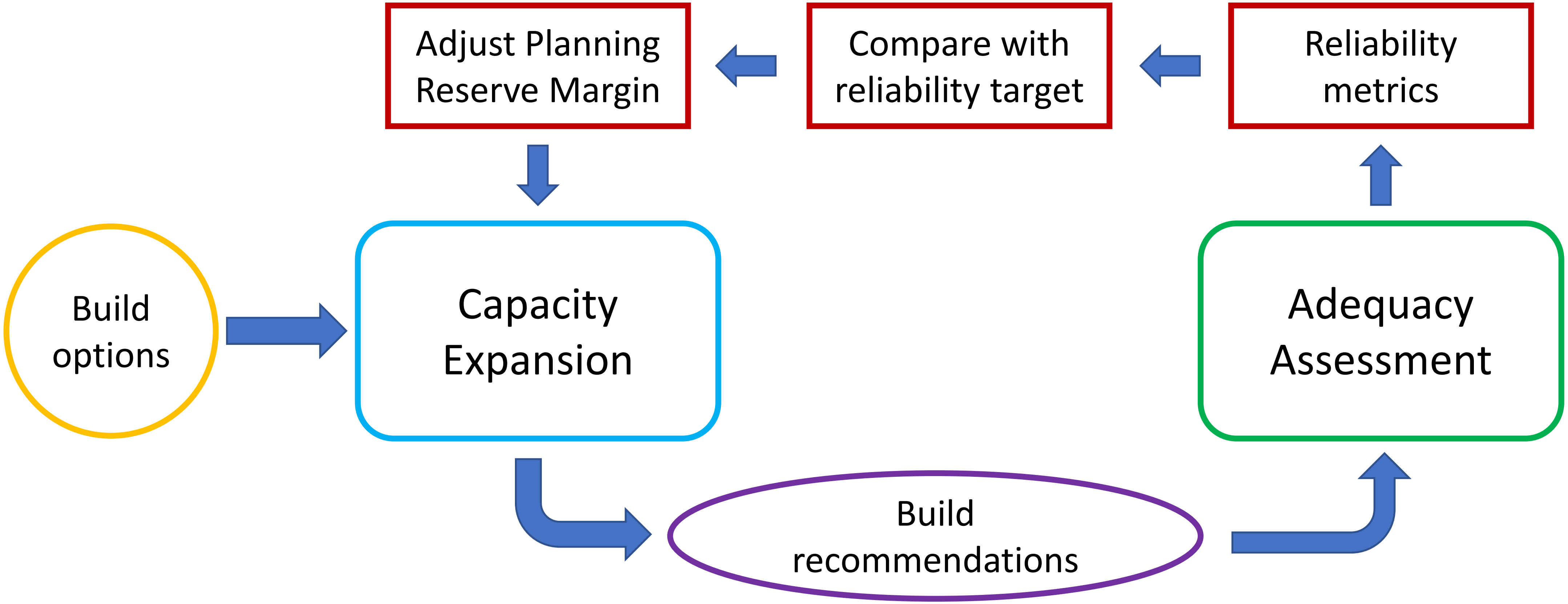
Practically…



Interesting but not really practical

Optimizing the Planning Reserve Margin

Evaluating resource adequacy impacts on energy market prices across wind and solar penetration levels.
B. Frew, G. Stephen, D. Sigler, J. Lau, B. Jones, A. Bloom, The Electricity Journal, 2019.



Adequacy with renewable resources

Conventional vs. renewable resources

- Conventional resources
  - Relatively few generating units
  - Large generating units
  - Random, uncorrelated failures
  - Uniform probability of failure
  - Worst case: failure during peak load period
- Renewable resources
  - Many smaller generating units
  - Failures of individual units do not significantly affect adequacy
  - Correlated variability in output
  - Worst case is harder to anticipate
  - Must consider many more periods when assessing adequacy

Capacity Credit of Conventional Generation

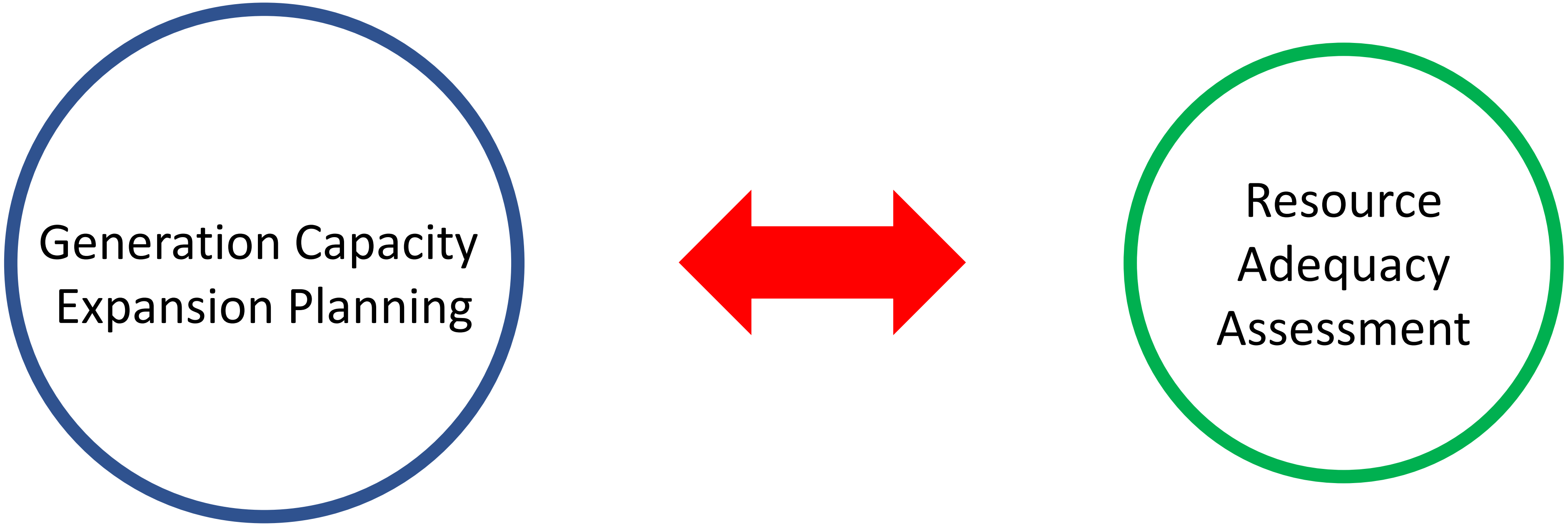
- How much generation will actually be available?
- Cannot assume rated capacity of all units
  - Some units will be on maintenance or otherwise unavailable
- Assume a sufficiently large number of conventional generating units
- Unavailability of conventional units is uncorrelated
- Capacity credit of conventional units:
  - Multiply the rated output of each unit by the average availability of this class of units
  - Independent of the number of units
  - Not affected by the season or the time of day

Capacity Credit for renewable resources

- Output of renewable generation
  - Depends on external factors (wind, sun, water)
  - Varies with season and time of day
  - Correlation between availability of different resources
- Various sophisticated probabilistic capacity credit calculation methods
- Valid for small additions to a specific system
- Must be recalculated as the generation portfolio changes
- Incremental capacity credit of renewables:
  - Decreases due to correlated unavailability
    - More solar does not help at night
  - Depends on availability of storage

→ Need to update the capacity credits as part of the optimization

Modeling operation over time



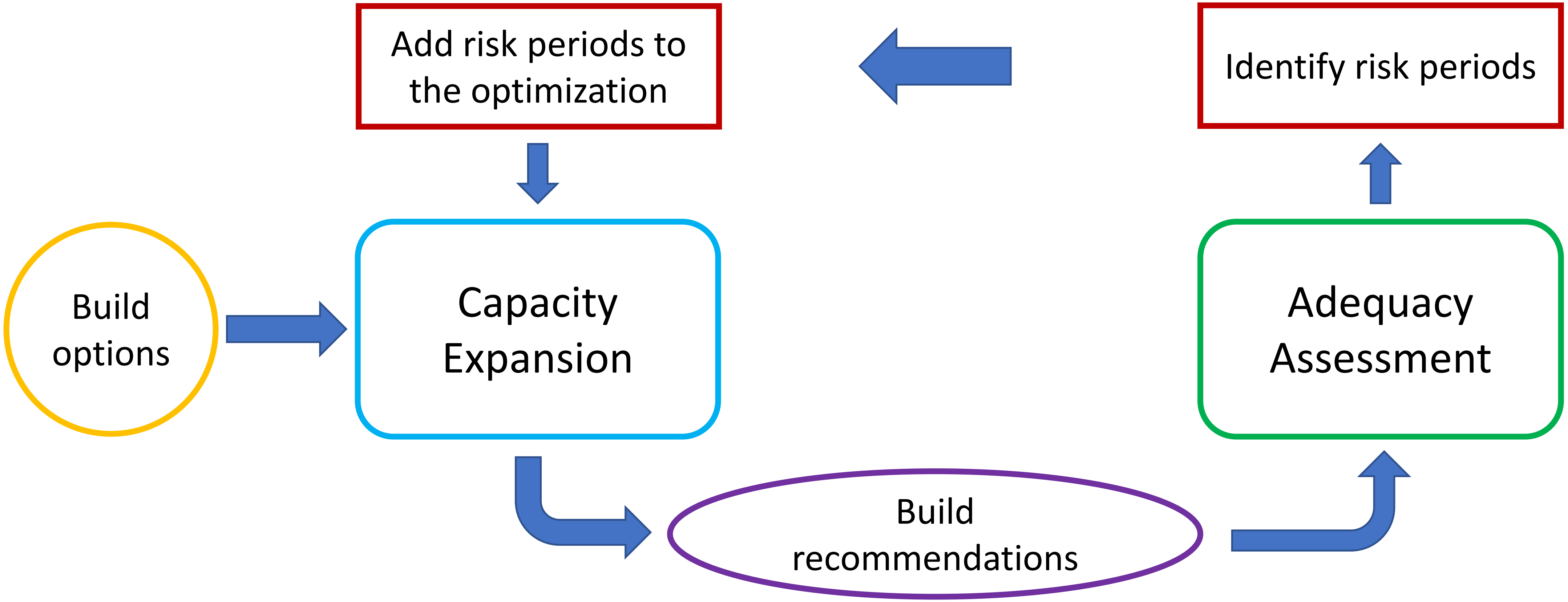
- Optimization with integer variables
- Modeling all days is computationally infeasible
- Capacity expansion driven by most stressful days
- Which days should be modeled in the optimization?

- Probabilistic assessment
- Accuracy requires hour-by-hour simulation over a long period
- Simulation over a whole year is feasible

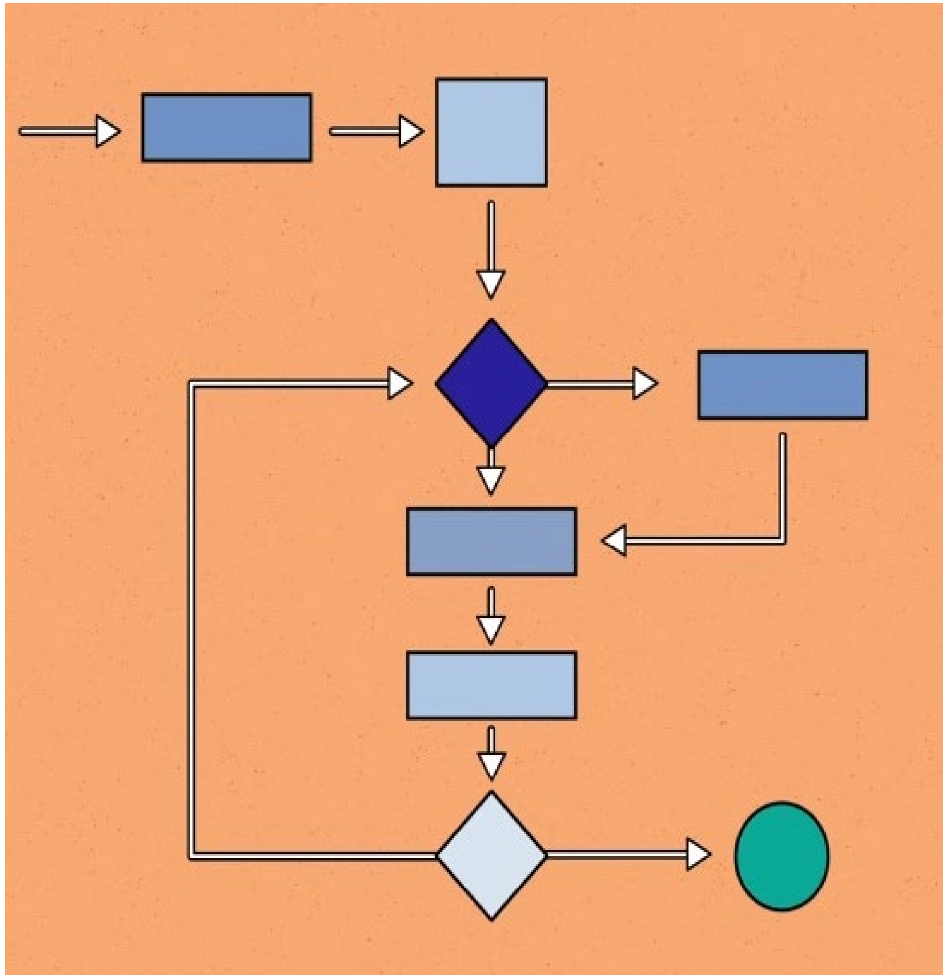
Selecting days for the expansion planning

- Peak load days
  - Sufficient when there is only conventional generation
  - Unlikely to be days when renewable generation is low
- Include summer, winter, spring, and autumn days
  - Better but still no guaranteed to capture inadequacy
- Add extreme days
  - How do you define ”extreme”?
  - Depends on generation portfolio
- Iteratively adding risk periods

Risk period iteration



Risk period iteration algorithm

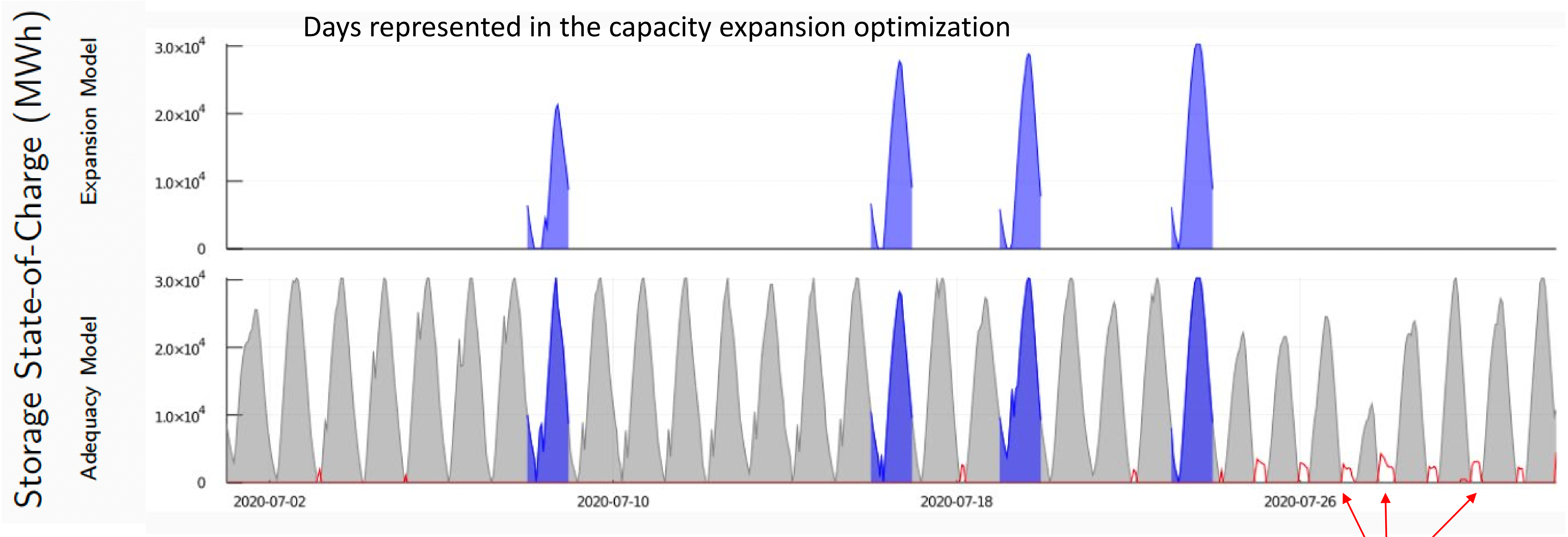


1. Define an initial set of representative days
2. Optimize the generation capacity expansion
3. Perform a chronological resource adequacy assessment
4. If adequacy metrics are satisfied, exit
5. Else, identify the day with the worst amount of unserved energy
6. Add this day to the set of representative days
7. Go to step 2

Example: initial set of representative days

Add storage capacity

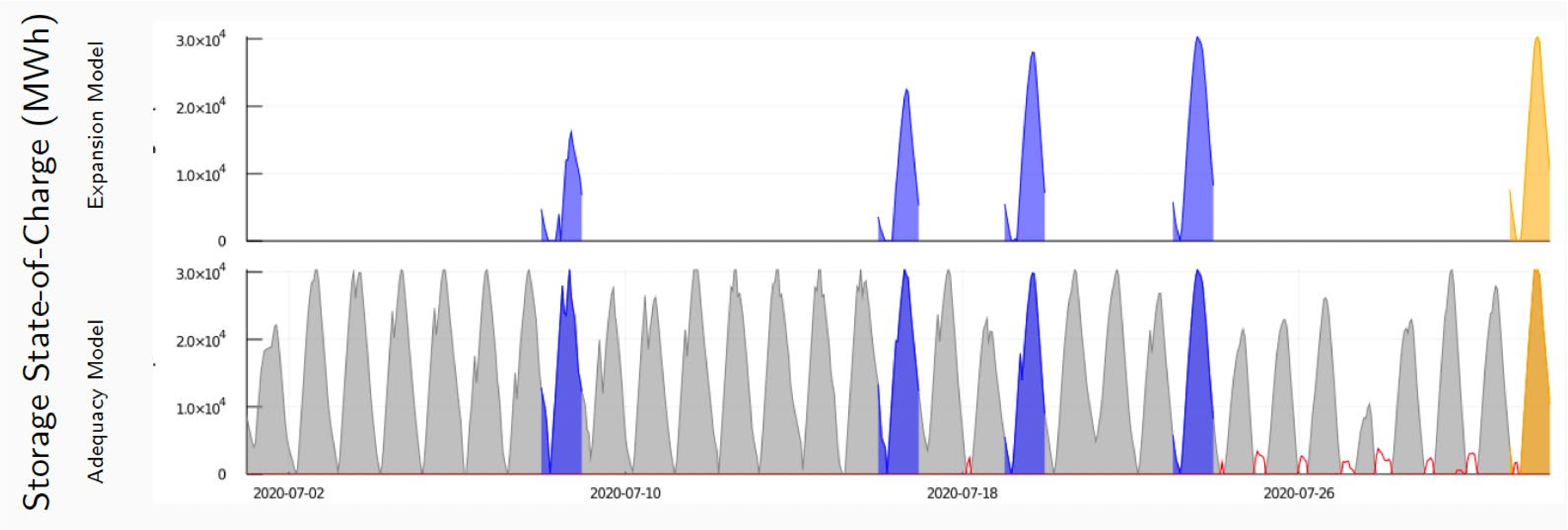
Days represented in the capacity expansion optimization



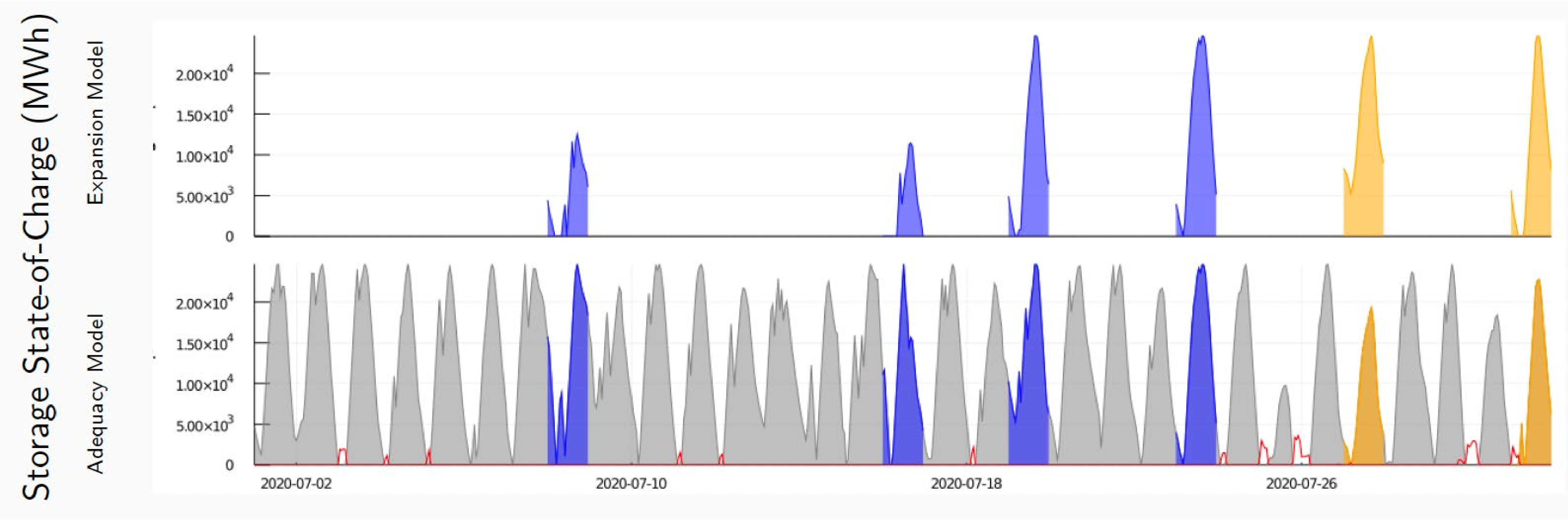
Days represented in the adequacy assessment

Unserved energy

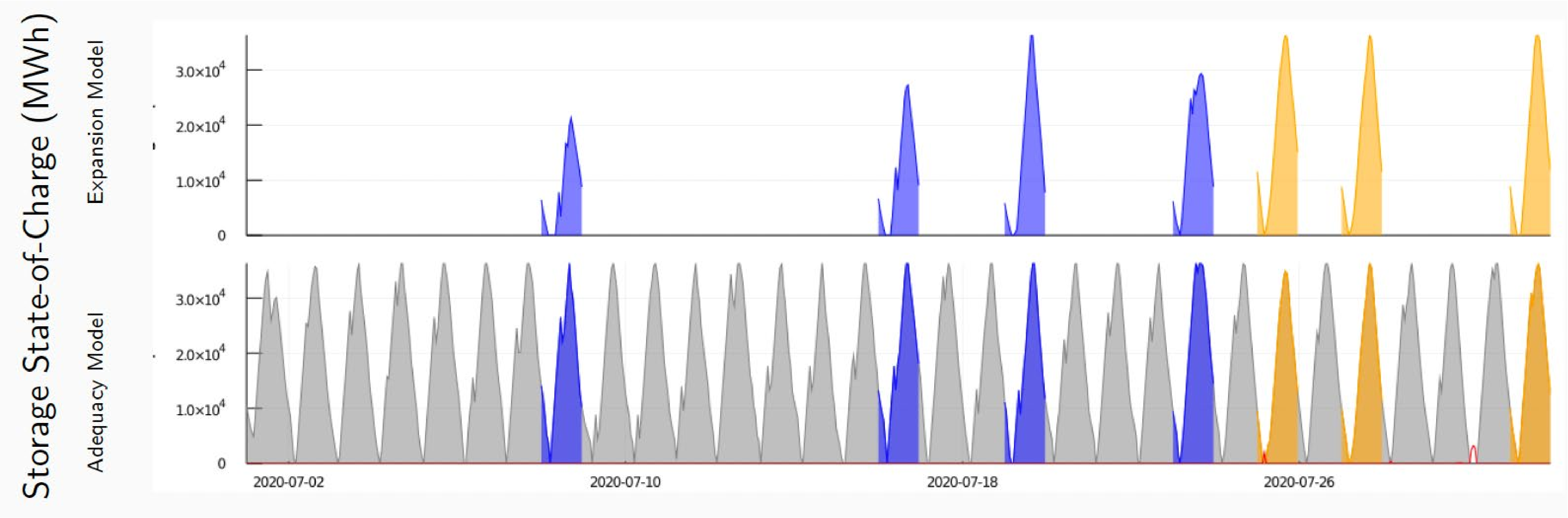
Add the worst day to the optimization



Add another day…

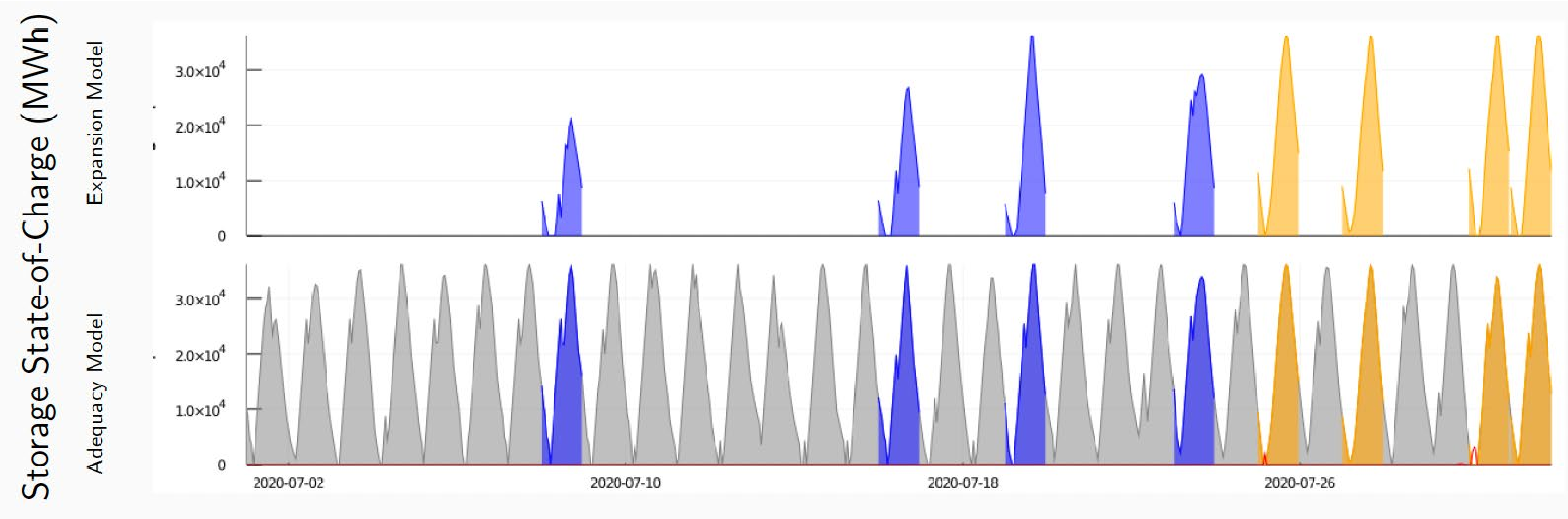


And another …



Storage State-of-Charge (MWh)
Expansion Model
Adequacy Model
3.0x10^4
2.0x10^4
1.0x10^4
0
2020-07-02
2020-07-10
2020-07-18
2020-07-26

And finally:



Storage State-of-Charge (MWh)
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2020-07-18
2020-07-26

Sizing storage

- Storage has two ratings
  - Capacity rating (MW)
  - Energy rating (MWh)
- Two approaches:
  - Define discrete technology types
    - E.g., 2-hour, 4-hour, 8-hour storage
    - Increases the size of the integer optimization
  - Optimize energy and capacity separately

Testing

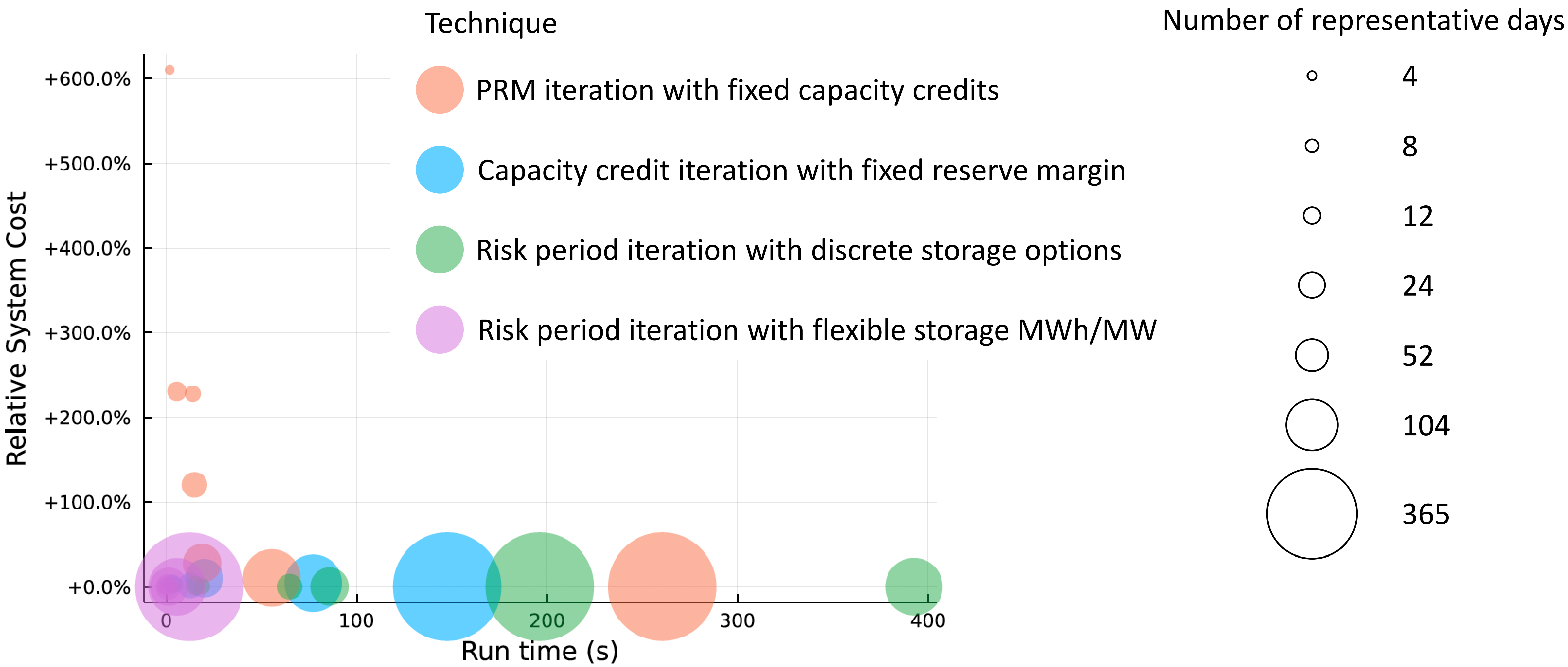
- Four techniques
  - Planning Reserve Margin iteration with fixed capacity credits
  - Capacity credit iteration with fixed reserve margin
  - Risk period iteration with discrete options for storage
  - Risk period iteration with flexible storage MWh/MW ratios

- Tested on GMLC test system

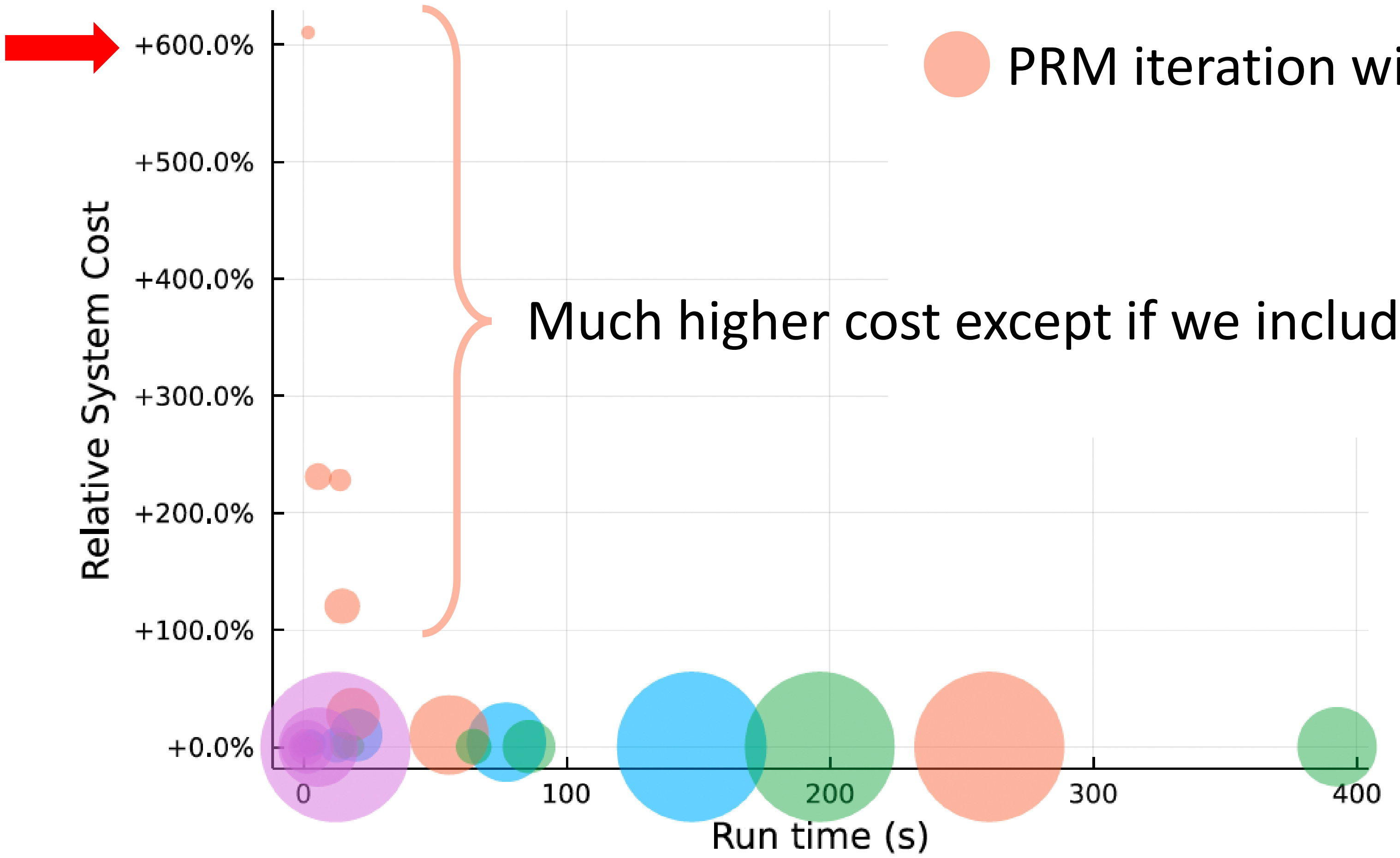
Testing

- Choice of representative days
  - 4: One representative day for each season
  - 8: One weekday and one weekend day for each season
  - 12: One representative day for each month
  - 24: One weekday and one weekend day for each month
  - 52: One representative day for each week
  - 104: One weekday and one weekend day for each week
  - 365: Every day of the year
- These days are fixed for the PRM iteration techniques
- They are updated for the risk period iteration techniques

Test results

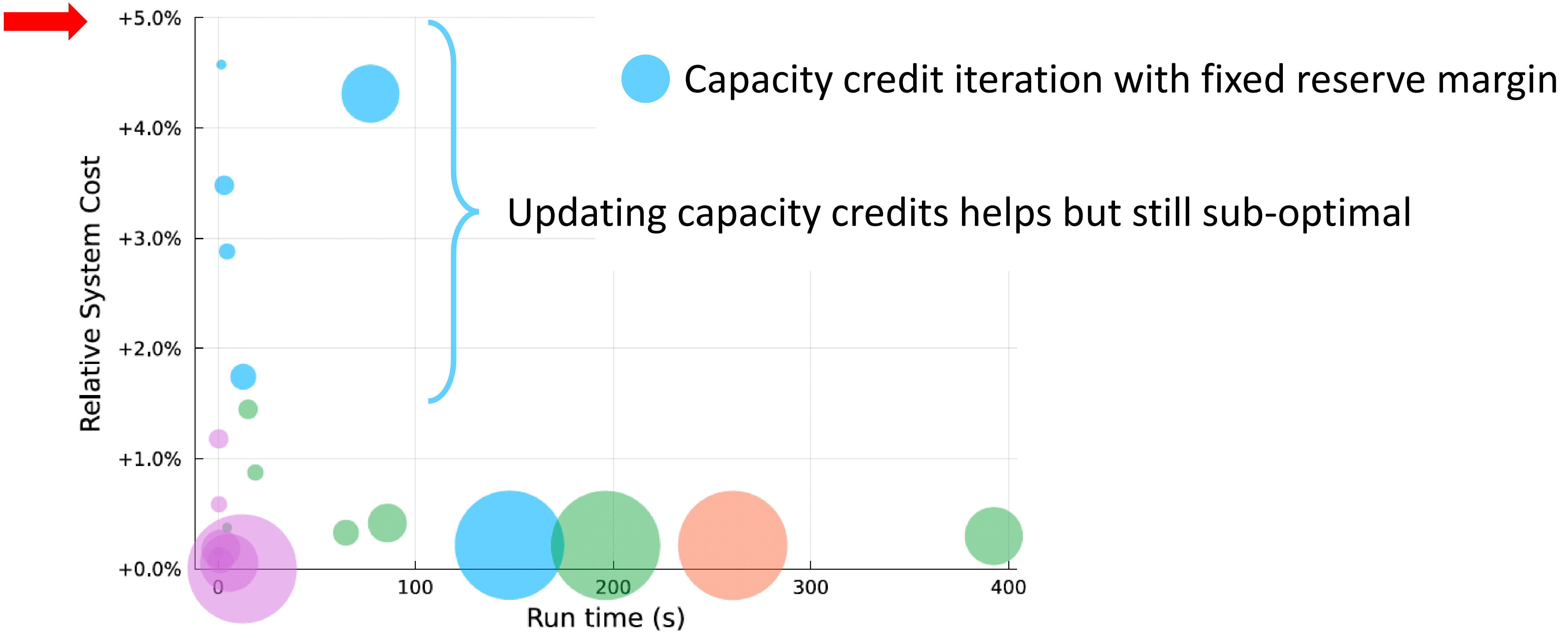


PRM iteration with fixed capacity credits

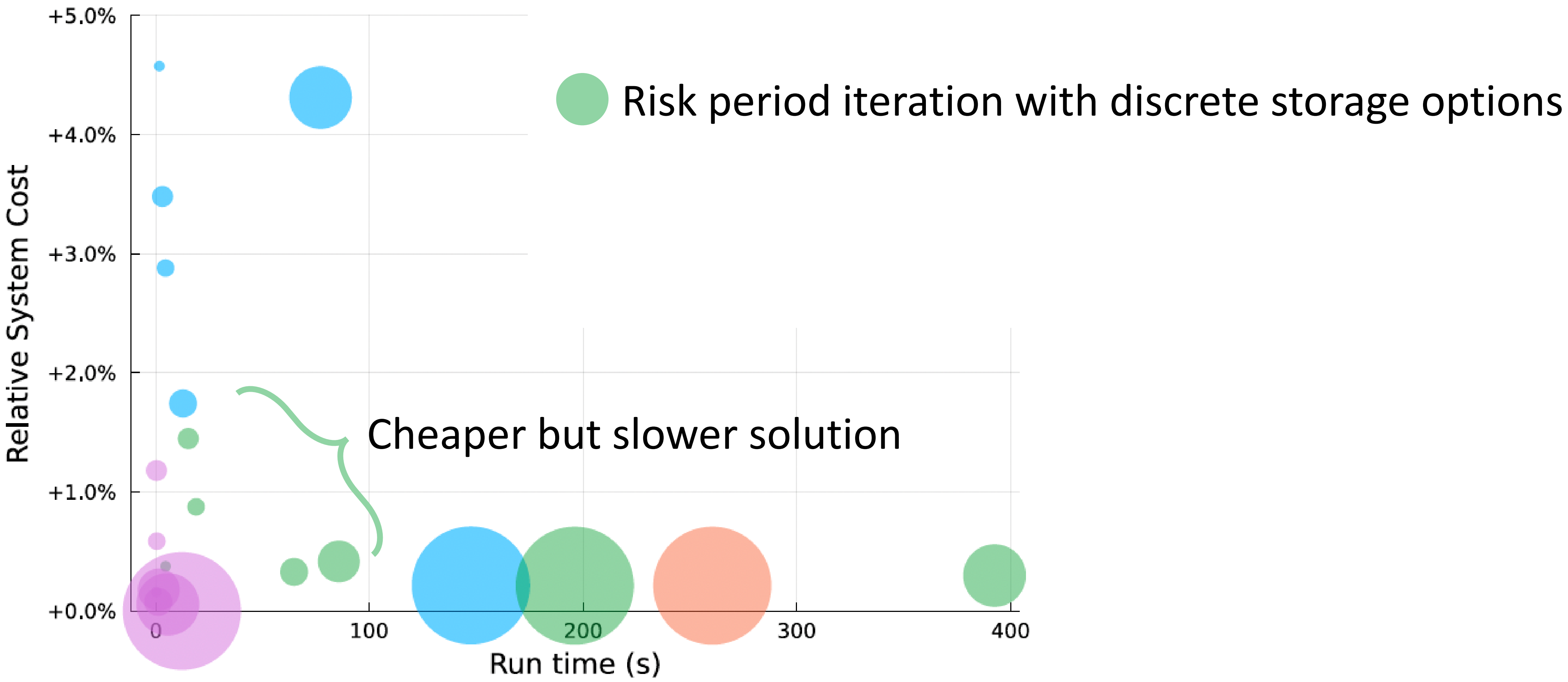


Much higher cost except if we include a lot of representative days!

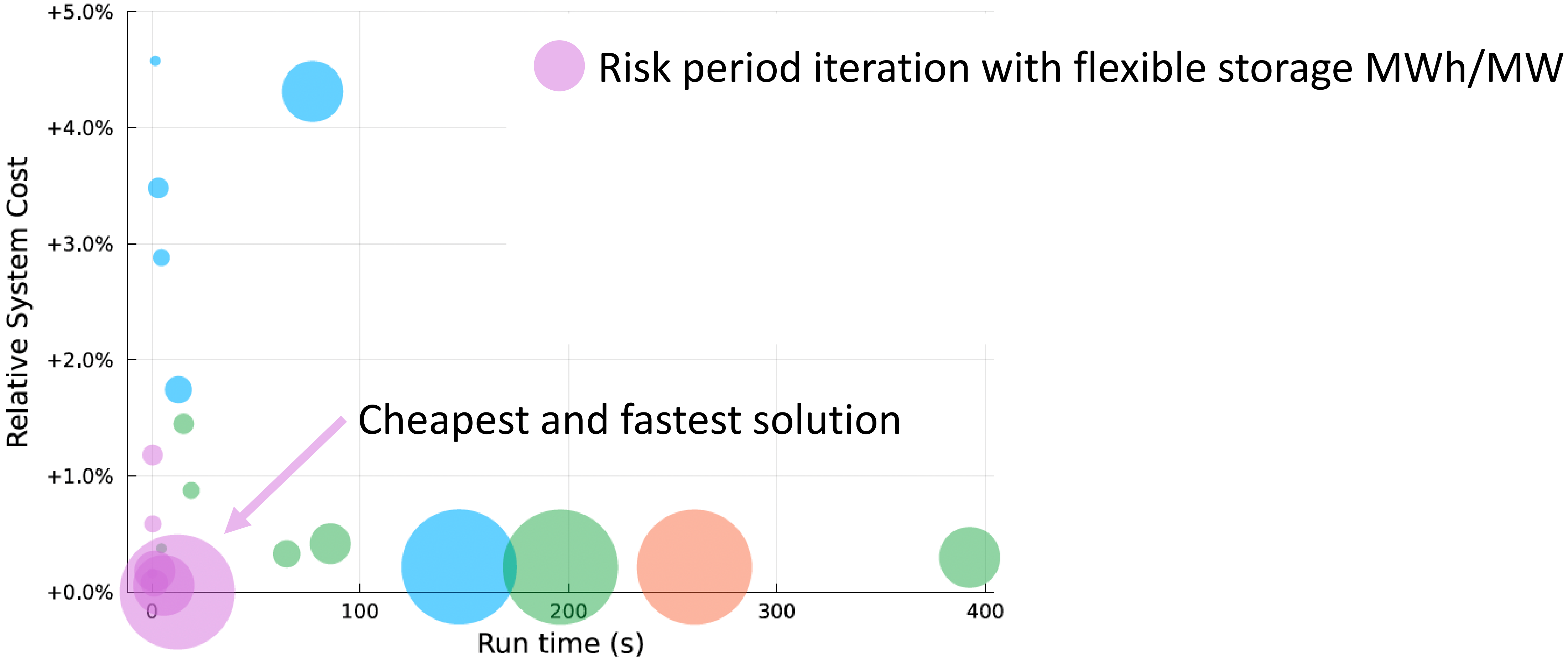
Capacity credit iteration with fixed reserve margin



Risk period iteration with discrete storage options



Risk period iteration with flexible storage MWh/MW



Conclusions about capacity expansion planning

- It is not:
  - “How much generation should we build?”
- It is:
  - “How much generation of each type should we build?”
- It is also:
  - “How much storage and what type of storage should we build?”
- Deployment of variable renewable generation makes this problem more difficult
- Must iterate optimizing the generation portfolio with the identification of days that are critical for adequacy

Backup Slides

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Longer duration storage

- Purely diurnal operation of storage
  - Final state of charge = initial state of charge
  - Treat each day separately
- Use storage to shift energy across days
  - Add to the optimization the day **before** the day with worse unserved energy
  - Give the system the opportunity to pre-charge the storage
- Effective but computationally inefficient for very long duration storage
- Concept of consecutive similar dispatch days

Model 20 days as six times three day-types