Dissertation Defense

Electricity Market Operations with Massive Renewable Integration: New Designs

Shengfei Yin
Adviser: Prof. Jianhui Wang

Summer 2021

World Changers Shaped Here

SMU®

Outline

- Introduction and Background
- **Long-term Study**: System Planning towards 100% Renewable Penetration
- **Short-term Study**: Transmission and Distribution Coordinated Market Hierarchy
- **General Development**: Multi-timescale Market Coordination with New Designs
- Summary

Outline

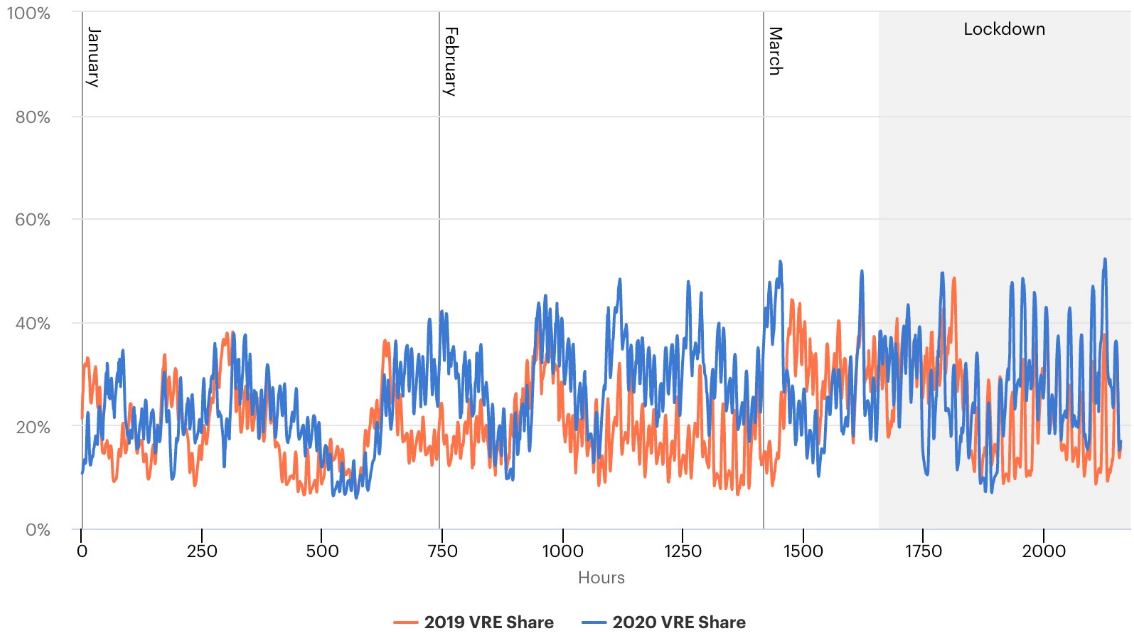
- Introduction and Background
- **Long-term Study**: System Planning towards 100% Renewable Penetration
- **Short-term Study**: Transmission and Distribution Coordinated Market Hierarchy
- **General Development**: Multi-timescale Market Coordination with New Designs
- Summary

Introduction – Current Electricity Market

- Electricity is a special commodity. It is transacted and consumed immediately. While the demand/supply also vary continuously, it is impossible to have a normal market to stock, ration, or queue.
- Electricity market in the U.S. is divided into different areas and regulated by independent system operators (ISOs).
- They include **long-term planning** and **short-term operation**.

Source: FERC Website: https://www.ferc.gov/industries-data/market-assessments/electric-power-markets

Introduction – Renewable Penetration



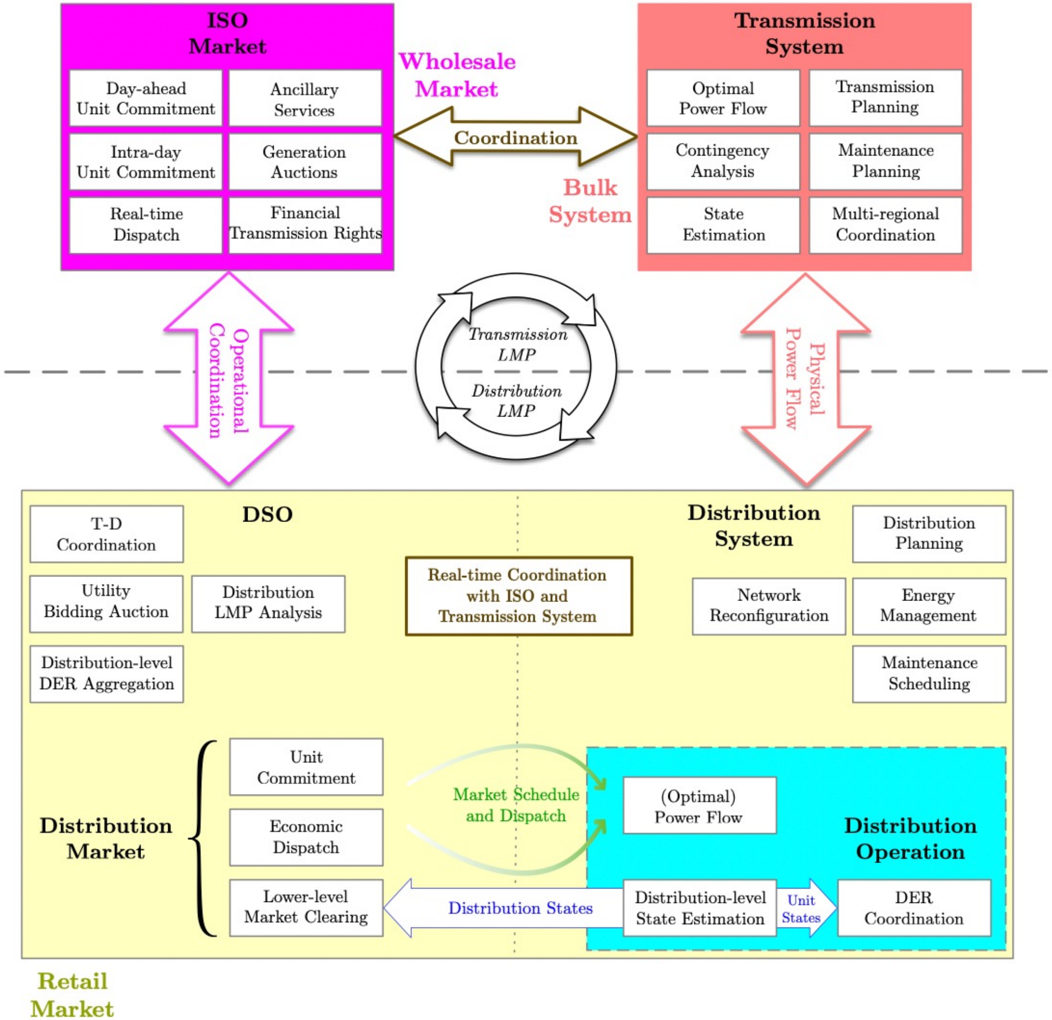
Renewable portion of load serving in Europe

- The global renewable penetration has been keeping increasing in a phenomenal rate.
- Renewables have zero marginal cost, which asks for a better market framework to optimize its revenue.

Source: IEA based on RTE (France), TERNA (Italy), ELEXON (United Kingdom), Red Eléctrica (Spain) and ENTSO-E

Background – Future Market Hierarchy

- Transmission side will need more visions from the distribution side.
- Local energy network management will become more critical.



Background – Stochastic Programming (SP)

- Scenario-based high-level optimization structure, which poses randomness in the parameters of objective or constraints.
- Multiple scenarios can capture the variations of the uncertain data by scenario generation techniques.
- A typical two-stage stochastic linear program:

$$\begin{aligned} \min_x \;\; & f(x) = c^\top x + \mathbb{E}\{Q(x,\tilde{\omega})\} \\ \text{s.t. } & x \in \mathcal{X} := \{Ax \le b, x \ge 0\}. \end{aligned}$$

$$\begin{aligned} Q(x,\omega) = \min_y \;\; & g(\omega)^\top y(\omega) \\ \text{s.t. } & D(\omega) \cdot y(\omega) \leqslant r(\omega) - C(\omega) \cdot x, \;\; y(\omega) \ge 0. \end{aligned}$$

Background – Robust Optimization (RO)

- Boundary-constrained special case for the stochastic programming, trying to find the risk-averse solution under the worst-case scenario.
- When there is lack of data and strict violation criteria are present, RO is the best way to formulate the problem.

$$\max_{u \in \mathcal{U}} \min_{x \in X} \quad c^\top x + d^\top u$$
$$\text{s.t.} \quad G^\top x \leq r - H^\top u$$

- RO dramatically reduces the computational time compared with SP but yields conservative solutions.

Background – Power Market Optimization

- Long-term Planning: Mixed-integer programming.
  - To optimally decide whether a system component should be invested in a long-term horizon considering the economic payback.
- Short-term Unit Commitment: Mixed-integer programming.
  - To optimally decide the startup/shutdown of generators in a short-term horizon. Part of the market clearing process.
- Short-term Economic Dispatch: Linear programming
  - To optimally decide the generation schedules of generators in a short-term horizon. Part of the market clearing process.

Outline

- Introduction and Background
- **Long-term Study**: System Planning towards 100% Renewable Penetration
- **Short-term Study**: Transmission and Distribution Coordinated Market Hierarchy
- **General Development**: Multi-timescale Market Coordination with New Designs
- Summary

G&TEP in a nutshell

- Generation and Transmission Expansion Planning (G&TEP) obtains an optimal investment portfolio for generators and transmission lines throughout the planning horizon.
- It involves with two parts, i.e., investment decisions and operating decisions:

Optimization-Based G&TEP

$$\underbrace{\min \sum_t c^\top I_t}_{\text{Investment}} + \underbrace{\min \sum_t \sum_h g^\top P_{t,h}}_{\text{Operation}}$$

c, g : Cost

t : Year

h : Hour

Coordinated SP and RO

- In the G&TEP problem, we have a lot of historical data for variable generation and demand, which can easily generate a lot of scenarios for SP.
- In the power system, N-k contingency is a well-known criteria, which perfectly fits the idea of worst-case scenario of RO. The contingency is also very critical in the system.
- Coordinated SP and RO is the chosen one.

$$\min_{I_t} \sum_t c^\top I_t + \max_{a_h} \mathbb{E}_\omega \left\{ \min_{P_{t,h}} \sum_t \sum_h g^\top P_{t,h}(\omega) \right\}$$

a_h : Outage indicator

ω : Index for operating scenarios

Formulation: Objective Function

Conventional Generator

Renewable Generator

Transmission Line

Investment Decisions

$$\min_{x^G_{g,t},x^R_{g,t},x^L_{\ell,t}} \sum_t^T \underbrace{\left(\sum_g^{X^G} IC^G_{g,t} x^G_{g,t} + \sum_g^{X^R} IC^R_{r,t} x^R_{r,t} + \sum_\ell^{X^L} IC^L_{\ell,t} x^L_{\ell,t} \right)}_{\text{Investment}}$$

Operation Variables

Outage Indicators

$$+ \max_{a^G_{g,t},a^L_{\ell,t}} \mathbb{E}_\omega \left\{ \min_{p^G_{g,h},r_{d,h}} \sum_h^H \left[\sum_g^G OC_{g,h} p^G_{g,h}(\omega) + \right.\right.$$

Active Power Cost

$$\left.\left. \sum_d^D PC_{d,h} r_{d,h}(\omega) \right] \right\} \quad (1)$$

Active Load Shedding Cost

Operation

Formulation: First-stage and Second-stage

- First-stage constraints

$$\sum_{t}^{T} \left\{ \sum_{g}^{X^G} IC^{G}_{g,t} x^{G}_{g,t} + \sum_{g}^{X^R} IC^{R}_{r,t} x^{R}_{r,t} \right\} \leq B^G,$$

Generation Expansion Budget

$$\sum_{t}^{T} \left\{ \sum_{\ell}^{X^L} IC^{L}_{\ell,t} x^{L}_{\ell,t} \right\} \leq B^L,$$

Transmission Expansion Budget

- Second-stage constraints

$$\sum_{g}^{G} a^{G}_{g,t} + \sum_{\ell}^{L} a^{L}_{\ell,t} \leq K_t, \quad \forall t,$$

N-k Contingency Enforcement

Formulation: Third-stage

Uncertain Parameter:
Active Demand

$$\sum_{g|c(g)=n}^{G} p^G_{g,h}(\omega) + \sum_{r|c(r)=n}^{R} p^R_{r,h}(\omega) - \sum_{\ell|S(\ell)=n}^{L} f_{\ell,h}(\omega) + \sum_{\ell|V(\ell)=n}^{L} f_{\ell,h}(\omega) = \sum_{d|c(d)=n}^{D} \{ P_{d,h}(\omega) - r_{d,h}(\omega) \}, \quad \forall n, \forall h,$$

Active Power Balance

$$f_{\ell,h}(\omega) = X_\ell^{-1}[\delta_{\ell|S(\ell)=n,h}(\omega) - \delta_{\ell|V(\ell)=n,h}(\omega)], \forall \ell \in L, \forall h,$$

DC Power Flow

$$-x^L_{\ell,t}(1-a^L_{\ell,t})FL_\ell \le f_{\ell,h}(\omega), \quad \forall \ell \in X^L, \forall (t,h) \in M,$$

$$f_{\ell,h}(\omega) \le x^L_{\ell,t}(1-a^L_{\ell,t})FL_{\ell,h}, \forall \ell \in X^L, \forall (t,h) \in M,$$

$$-(1-a^L_{\ell,t})FL_\ell \le f_{\ell,h}(\omega), \quad \forall \ell \in L \backslash X^L, \forall (t,h) \in M,$$

$$f_{\ell,h}(\omega) \le (1-a^L_{\ell,t})FL_{\ell,t}, \forall \ell \in L \backslash X^L, \forall (t,h) \in M,$$

Power Flow Thermal Limits w.r.t the Investment Decisions and Outage Indicators

Formulation: Third-stage (Cont'd)

$$p^G_{g,h}(\omega) \le x^G_{g,t}(1-a^G_{g,t})\overline{PL}^G_g, \forall g \in X^G, \forall (t,h) \in M,$$
$$p^G_{g,t}(\omega) \le (1-a^G_{g,t})\overline{PL}^G_g, \quad \forall g \in G \backslash X^G, \forall (t,h) \in M,$$

Power Capacity for Conventional Generators

$$p^R_{r,h}(\omega) \le x^R_{r,t}(1-a^R_{r,t})\overline{PL}^R_{r,h}, \forall r \in X^R, \forall (t,h) \in M,$$
$$p^R_{r,h}(\omega) \le (1-a^R_{r,t})\overline{PL}^R_{r,h}, \forall r \in R \backslash X^R, \forall (t,h) \in M,$$

Power Capacity for Renewable Generators

Uncertain Parameter:
Active Renewable Available Power

$$\underline{\Delta}_{n,h} \le \delta_{n,h}(\omega) \le \overline{\Delta}_n, \quad \forall n, \forall h,$$
$$x^G_{g,t}, x^R_{g,t}, x^L_{\ell,t} \in \{0,1\}, \quad \forall g, \forall r, \forall \ell, \forall t,$$
$$a^G_{g,t}, a^L_{\ell,t} \in \{0,1\}, \quad \forall g, \forall \ell, \forall t.$$

Power Angle Limits and Status Indication

Decomposition Framework

Multiplex
Uncertainty-based
Coordinated Planning

Mixed-integer Stochastic
Nonlinear Programming

C&CG
Algorithm

Master Problem

Binary Programming

↓

Investment Decisions

Subproblem

Mixed-integer Stochastic
Nonlinear Programming

L-shaped
Method

Sub-Master Problem

Binary Programming

↓

Worst-case Contingency

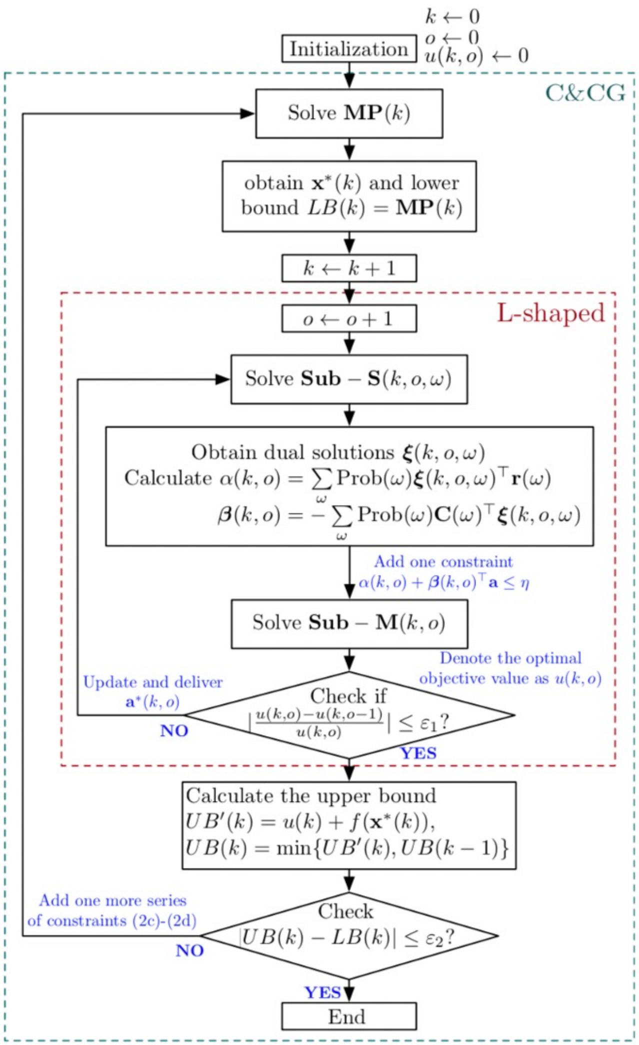
Sub-Subproblem

Relaxed Stochastic
Linear Programming

↓

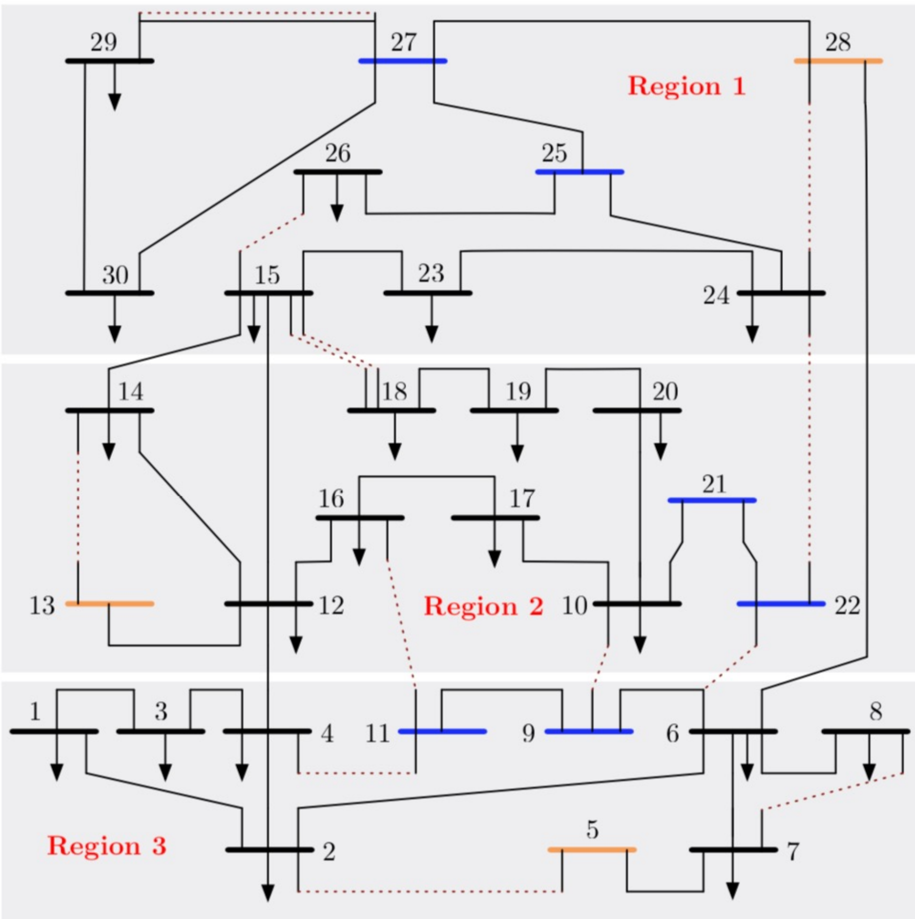
Operation Costs

Overall Workflow



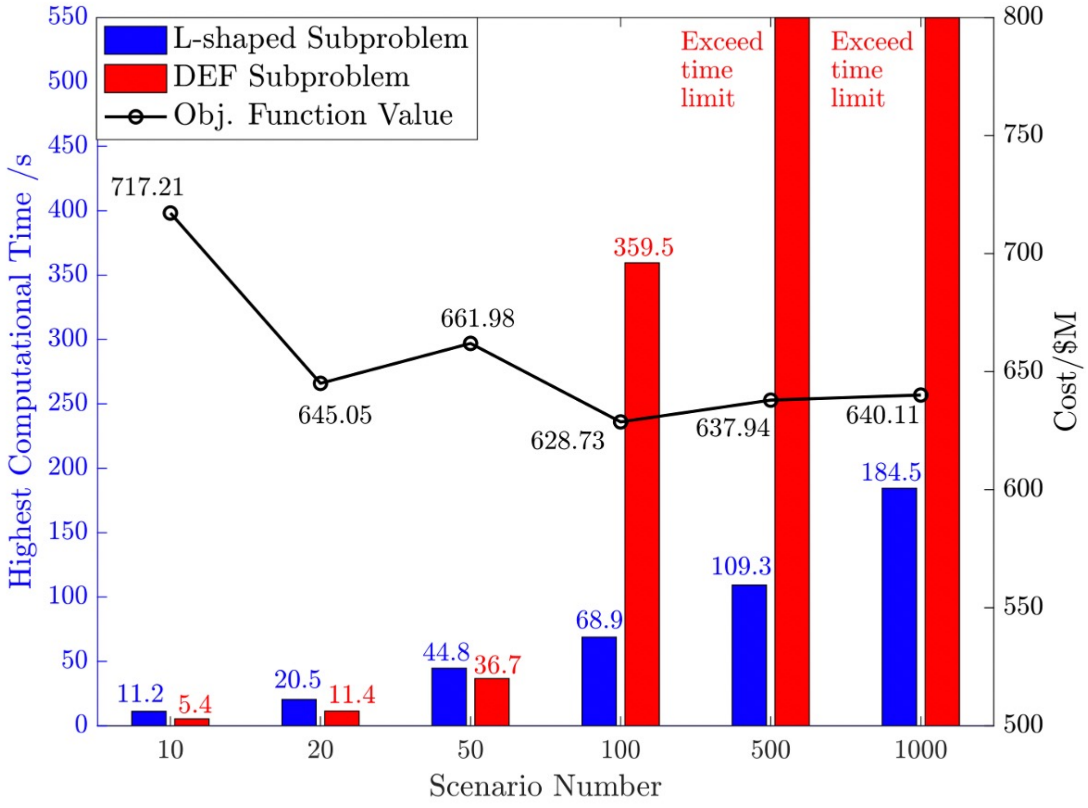
- Convergence:
  - The proposed algorithm guarantees its convergence by the finite extreme points of the uncertainty set and finite support in the second-stage stochastic recourse.
  - The convergence of the C&CG part relies on the convergence of the L-shaped algorithm
  - Subproblems can be solved in parallel to enhance computability.

Numerical Experiments: Case Settings



- Modified IEEE 30-bus:
  - Divided by three regions.
  - Each region has two wind buses (blue) and one solar bus (orange) to invest corresponding generators.
  - Dashed lines are candidate transmission lines
  - Thermal generators (if allowed) can be built in any black bus.
  - 6-year planning with N-1 criterion in each region.

Sensitivity in Scenario Reduction



We perform a sensitivity analysis for testing different scenario number, and we found that 100 scenarios can achieve good solution quality and balance the tradeoff between the computational complexity and the accuracy.

Test Case I: For 100% Renewable Penetration

- Case 1: $900M generation investment budget (6yrs);
- Case 2: $9,000M generation investment budget (6yrs);
- Case 3: $9,000M generation investment budget. Thermal units can only be installed in the first year. All the thermal units will phase out by 20% capacity per year (6yrs) with a salvage income.
  - We consider a 5% annual fuel price inflation rate for thermal units;
  - We consider a 5% annual capital cost deflation rate for RES units;
  - We consider a 5% system demand increase rate (same distribution);
  - We use a 40% of the investment cost as the salvage income of phase-out thermal units.

Test Case I: Investment Portfolio

Gen. Investment*	Case 1	Case 2	Case 3
Year 1	2, 4, 6, 8, 10, 12, 14, 15, 18, 24, 29, 30	2, 4, 5, 5, 10, 9, 14, 15, 18, 21, 22, 24, 27, 29	4, 5, 5, 9, 9, 11, 11, 16, 21, 21, 22, 22, 25, 25, 27, 27, 30
Year 2	None	21	9, 13, 21, 22, 25, 25
Year 3	None	None	None
Year 4	None	None	None
Year 5	None	None	None
Year 6	None	None	None
Line Investment	Case 1	Case 2	Case 3
Year 1	4-11, 7-8, 6-22, 9-10, 15-26, 22-24,	4-11, 7-8, 6-22, 9-10, 15-18, 15-26, 22-24	4-11, 7-8, 6-22, 9-10, 15-18, 15-24, 15-26, 22-24
Year 2-6	None	None	None
Gen. Invest. Cost	\$813.6M	\$2,812.9M	\$7,237.4M
Gen. Opera. Cost	\$5,976.81M	\$3,542.70M	\$168.93M
Line Invest. Cost	\$300M	\$350M	\$400M
Load Shed Cost	0	0	\$1,079.43M
Salvage Income	0	0	\$81.36M
Total Cost	\$7,090.41M	\$6,705.60M	\$8,754.40M
Avg. Load Shed Portion	0%	0%	0.96%
Avg. Renewable Curtailment	0%	7.75%	12.11%
Final Renewable Percentage	0%	42.86%	100%

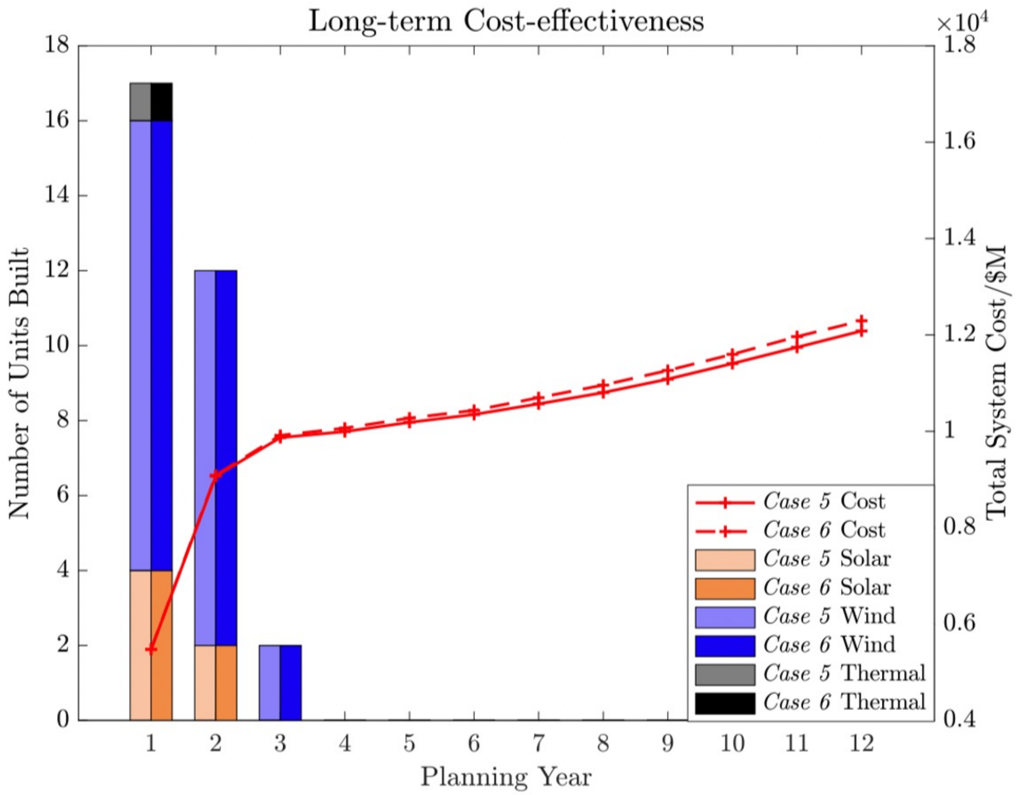
* The numbers indicate the buses built with thermal, wind and solar.

- Most of the investment happens in the first few years since the system has a complete information over the load growth and pricing.
- In Case 3, the total installed capacity of generators is 152.9% higher than the peak load due to the contingency criterion.
- Peak curtailment for Case 3 is 12.11%, which will serve as a good approach to provide ancillary services like regulation-up.

Test Case III: Long-term Cost-effectiveness

- Case 5: $12,000M generation investment budget (12yrs);
- Case 6: $12,000M generation investment budget. Thermal units can only be installed in the first year. All the thermal units phase 10% capacity out per year (12yrs).
  - We consider a 5% annual fuel price inflation rate for thermal units;
  - We consider a 5% annual capital cost deflation rate for RES units;
  - We consider a 5% system demand increase rate (same distribution);
  - We use a 40% of the investment cost as the salvage income of phase-out thermal units (Since they are used for fewer years).

Test Case III: Long-term Cost-effectiveness



- The system cost consists of investment cost and operation cost. In the longer term, the 100% renewable becomes comparatively more cost-effective.
- If taking feed-in-tariffs, energy storage, and demand response into account, 100% renewable will beat conventional resources.

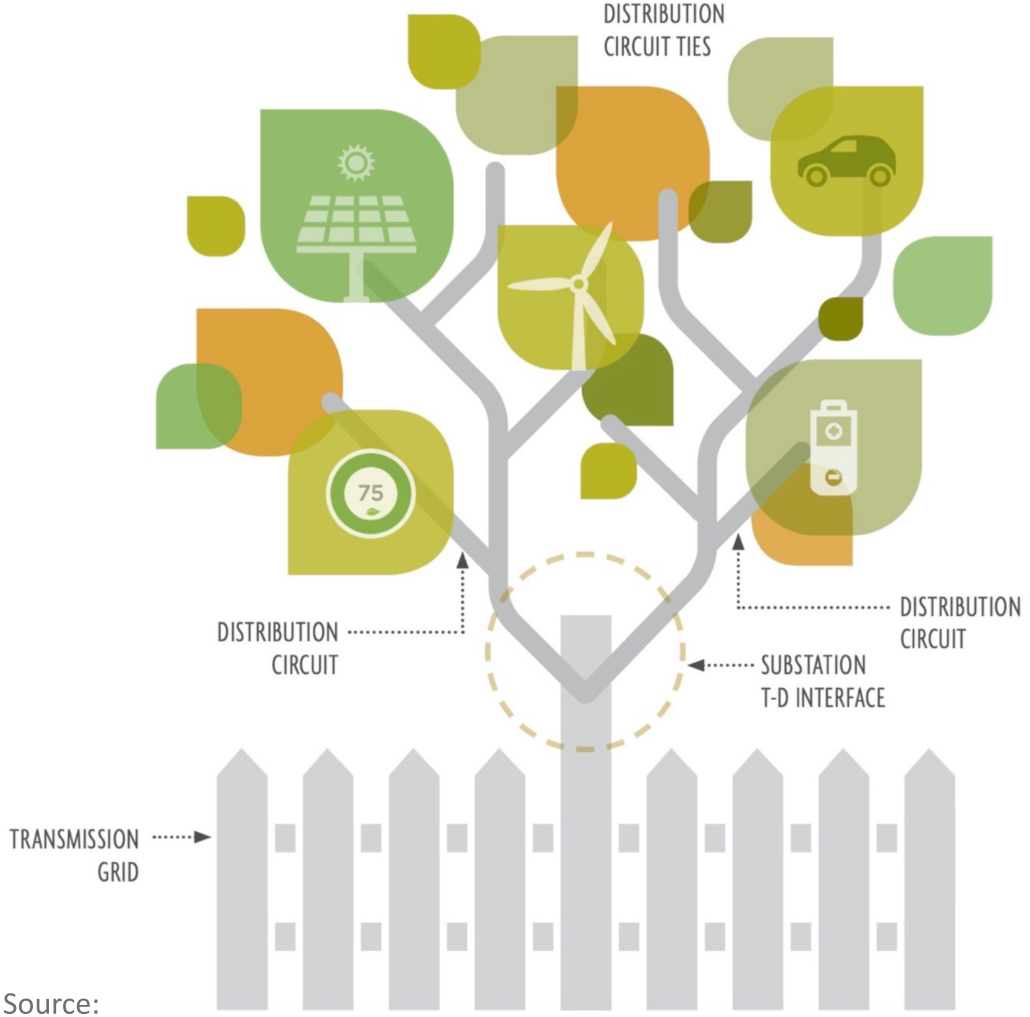
Remarks

- The hybrid stochastic and robust model can accurately capture the uncertainties in the modern power grid.
- We propose a hybrid solution strategy combining the C&CG and L-shaped algorithms that can efficiently tackle intractable uncertainty-based planning problems
- A proper portfolio of generation mix from the conventional and renewable generations is shown to be the most profitable solution in a short- or mid-term system planning problem. However, the 100% renewable penetration reveals its cost-effectiveness in a long-term window.

Outline

- Introduction and Background
- **Long-term Study**: System Planning towards 100% Renewable Penetration
- **Short-term Study**: Transmission and Distribution Coordinated Market Hierarchy
- **General Development**: Multi-timescale Market Coordination with New Designs
- Summary

Transmission-Distribution Coordination



Source:
https://www.caiso.com/Documents/MoreThanSmartReportCoordinatingTransmission_DistributionGridOperations.pdf

Industrial UC&ED in Transmission/Distribution

- Transmission Level:
  - ISO/RTO and TSO schedule the day-ahead and real-time UC and ED.
  - The demand on the distribution side is estimated and secured by corrective control and ancillary provisions.
  - Uncertainties are forecast and controlled by posterior correction.
- Distribution Level:
  - DSOs perform their own day-ahead and real-time OPF and ED.
  - The power injection from the transmission level is pre-determined.
  - Uncertainties are forecast and controlled by posterior correction.

Shortage:

High power mismatch in the boundary node.

Motivation

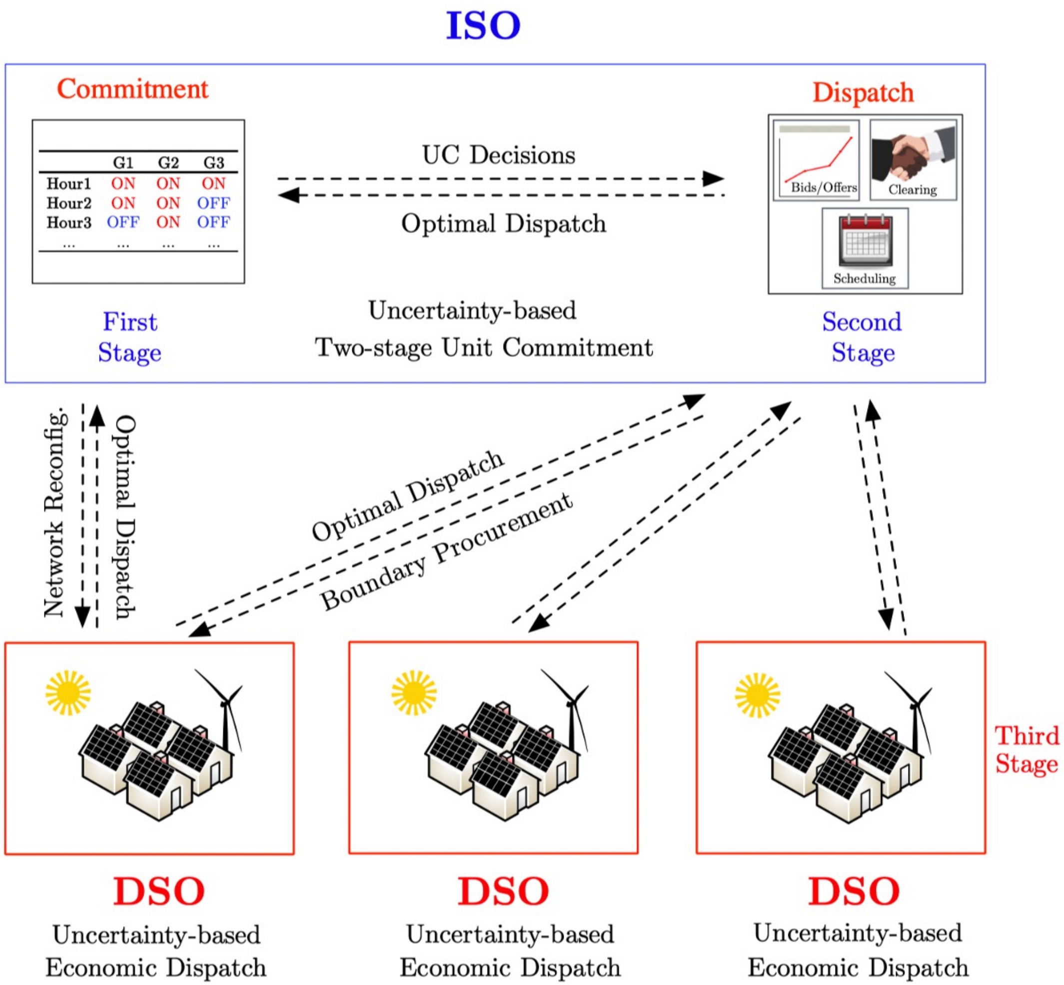
- Independent operational scheduling of TSO and DSO results in boundary power mismatch and economic suboptimality.
  - *A coordinated operation needs to be established.*
- Centralized operation becomes unacceptable since TSO and DSO have confidential information.
  - *A decentralized structure is necessary.*
- The general coordinator should monitor the competition between TSO and DSO.
  - A hierarchical master observer is in presence.

Contribution of this Work

- ***High power mismatch in the boundary node:***
  - A T-D coordinated UC&ED paradigm
- ***The consideration of uncertainties***
  - Wind/Solar renewable and elastic load uncertainties incorporated
- ***Accurate and tractable modeling***
  - SOCP-based AC power flow formulation with scenario generation/reduction from historical data
- ***Decentralizable, fast and optimality-assured algorithm***
  - A generalized nested multi-cut L-shaped method is devised.

The Proposed Paradigm

- ISOs still manage the overall operation.
- DSOs exchange boundary information including the dispatch and price values.
- The coordination indicates a natural multi-stage formulation.



General Insights

ISO's Master Problem

UC and
Network Configuration

(*Integer Programming*)

TSO's Subproblem

Wind/demand uncertainty
-based Transmission ED

(*Convex Programming*) <u>*Linear DC OPF*</u>

DSO's Subproblem

Solar/demand uncertainty
-based Distribution ED

(*Convex Programming*) <u>*Convexified AC OPF*</u>

Compact Form for Three Problems

- ISO's Master Problem

Binary Variables: $\mathbf{x}_1, \mathbf{x}_2, \mathbf{z}$

$$\bar{M} = \min_{\mathbf{x}_1, \mathbf{x}_2} \quad \mathbf{c}_1^\top \bar{\mathbf{x}}_1 + \mathbf{0}^\top \mathbf{x}_2 + S_t^*, \tag{4a}$$

$$\mathbf{A}_1\mathbf{x}_1 + \mathbf{B}_1\mathbf{x}_2 \leq \mathbf{b}_1, \tag{4b}$$

$$\mathbf{A}_2\mathbf{x}_1 + \mathbf{B}_2\mathbf{x}_2 = \mathbf{b}_2, \tag{4c}$$

$$S_t^* = \max_{o \in O} \left\{ \alpha_t^o + (\boldsymbol{\beta}_{t1}^o)^\top \mathbf{x}_1 + (\boldsymbol{\beta}_{t2}^o)^\top \mathbf{x}_2 \right\}, \tag{4d}$$

Cut

- TSO's Subproblem

Continuous Variables: $\mathbf{y}$

$$\forall \omega^T : \quad S_t(\omega^T) = \min_{\mathbf{y}} \quad \mathbf{c}_2^\top \mathbf{y} + S_d^*, \tag{5a}$$

$$\mathbf{K}_1\mathbf{y} = \mathbf{r}_1(\omega^T) : \qquad \gamma, \tag{5b}$$

$$\mathbf{H}_1\mathbf{x}_1^* + \mathbf{A}_3\mathbf{y} \leq \mathbf{b}_3 : \qquad \boldsymbol{\phi}, \tag{5c}$$

$$S_d^* = \max_{o \in O, c} \left\{ w_c \cdot \left[\alpha_d^o + (\boldsymbol{\beta}_{d1}^o)^\top \mathbf{y} + (\boldsymbol{\beta}_{d2}^o)^\top \mathbf{x}_2^* \right] \right\} : \boldsymbol{\mu}, \tag{5d}$$

Cut

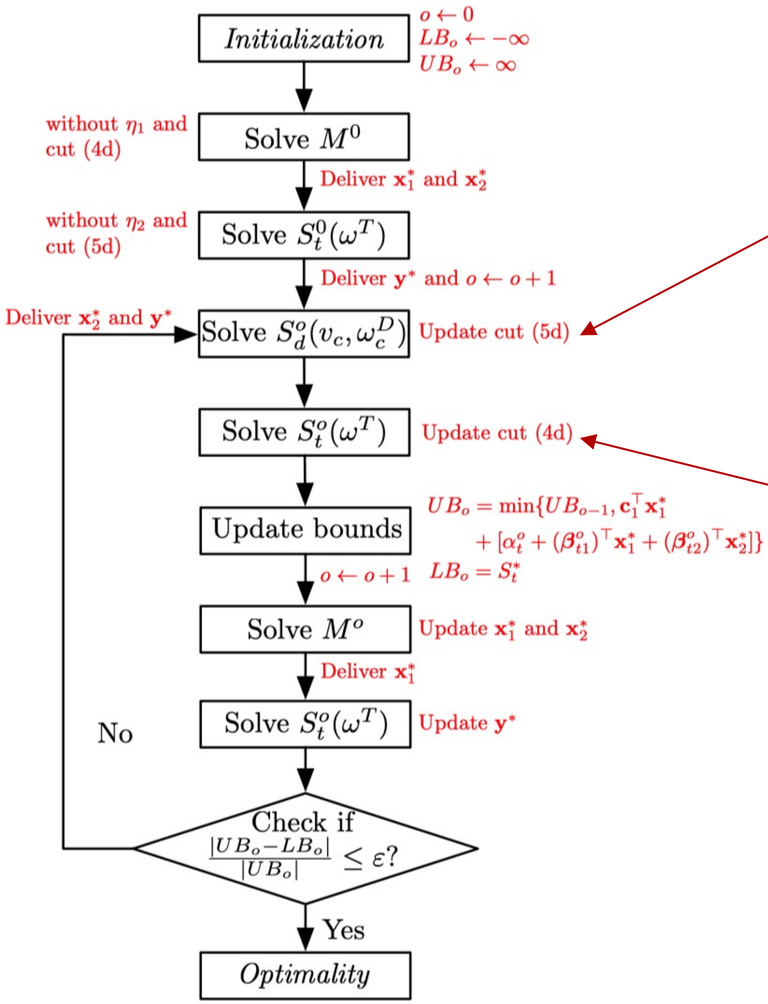
- DSO's Subproblem

$$S_d^{\text{dual}}(w_c, \omega_c^D) = \max_{\mathbf{u}, \mathbf{v}} \quad \Big[\mathbf{u}^\top (\mathbf{H}_2\mathbf{y}^* + \mathbf{e}) - \mathbf{v}(\mathbf{q}^\top \mathbf{y}^* + \mathbf{H}_3^\top \mathbf{x}_2^* + \mathbf{r}_2(\omega_c^D)) \Big], \tag{7a}$$

$$\mathbf{K}_2^\top \mathbf{u} + \mathbf{v}^\top \mathbf{p} = \mathbf{c}_3, \tag{7b}$$

$$\|\mathbf{u}\|_2 \leq \mathbf{v}, \tag{7c}$$

Generalized Nested Multi-cut L-shaped (NMLS)



For cut (5d):

$$S_d^* = \max_{o \in O, c} \left\{ w_c \cdot [\alpha_d^o + (\boldsymbol{\beta}_{d1}^o)^\top \mathbf{y} + (\boldsymbol{\beta}_{d2}^o)^\top \mathbf{x}_2^*] \right\}$$

Compute the subgradient coefficients:

$$\alpha_d^o = \sum_{\omega_c^D} \Pr_{\omega_c^D} [\mathbf{u}^\top \mathbf{e} - \mathbf{v} \cdot \mathbf{r}_2(\omega_c^D)];$$

$$\boldsymbol{\beta}_{d1}^o = \sum_{\omega_c^D} \Pr_{\omega_c^D} [\mathbf{u}^\top \mathbf{H}_2 - \mathbf{v} \cdot \mathbf{q}]; \;\; \boldsymbol{\beta}_{d2}^o = -\sum_{\omega_c^D} \Pr_{\omega_c^D} \mathbf{v} \cdot \mathbf{H}_3^\top$$

For cut (4d):

$$S_t^* = \max_{o \in O} \left\{ \alpha_t^o + (\boldsymbol{\beta}_{t1}^o)^\top \mathbf{x}_1 + (\boldsymbol{\beta}_{t2}^o)^\top \mathbf{x}_2 \right\}$$

Compute the subgradient coefficients:

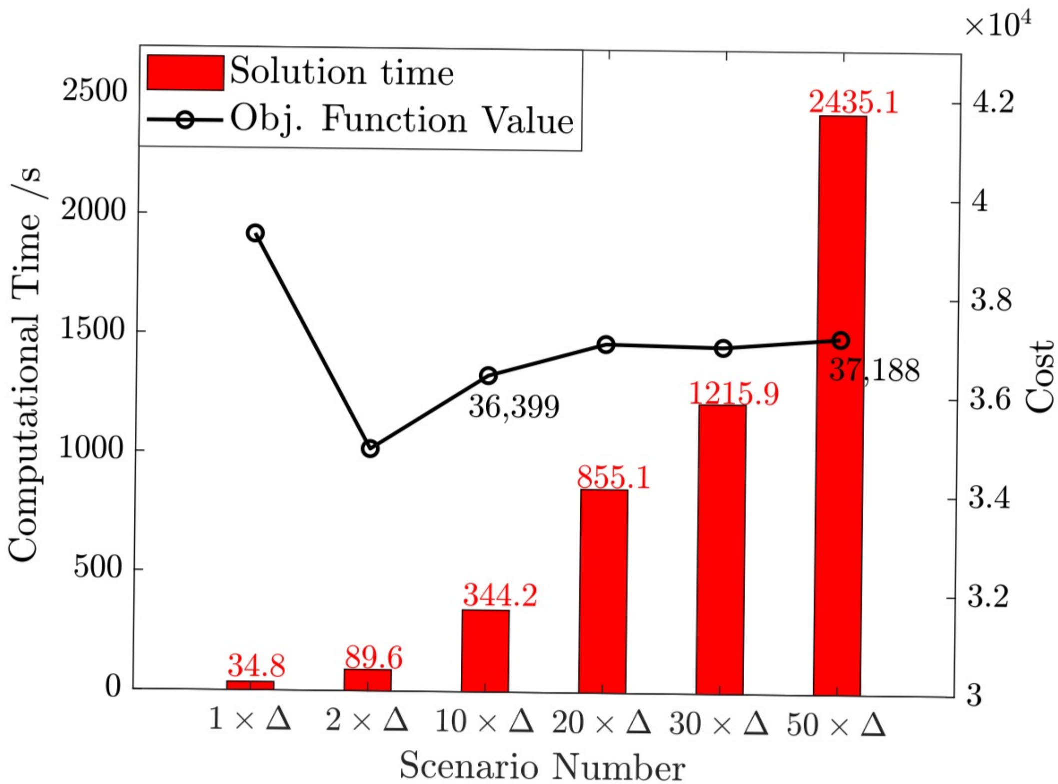
$$\alpha_t = \sum_{\omega_t} \Pr_{\omega_t} [\boldsymbol{\gamma}_1(\omega_d)^\top \mathbf{r}_1 - \boldsymbol{\mu}^\top \alpha_d + \boldsymbol{\phi}_1^\top \mathbf{b}_3];$$

$$\boldsymbol{\beta}_{t1} = -\sum_{\omega_t} \Pr_{\omega_t} \mathbf{H}_1^\top \boldsymbol{\gamma}_1(\omega_t); \;\; \boldsymbol{\beta}_{t2} = -\sum_{\omega_t} \Pr_{\omega_t} \boldsymbol{\beta}_{d2}^\top \boldsymbol{\mu}.$$

Convergence Analysis

- A Sketch for Convergence Proof:
  - Based on that the original nested L-shaped Method converges to optimality.
  - All scenarios render no infeasibility due to the penalty allowance.
  - Two subproblems are strictly convex, which holds the strong duality, and thus the hyperplane support created by cuts gives accurate approximations.
  - Finite number of integer variables and scenarios.

Sensitivity in Scenario Reduction

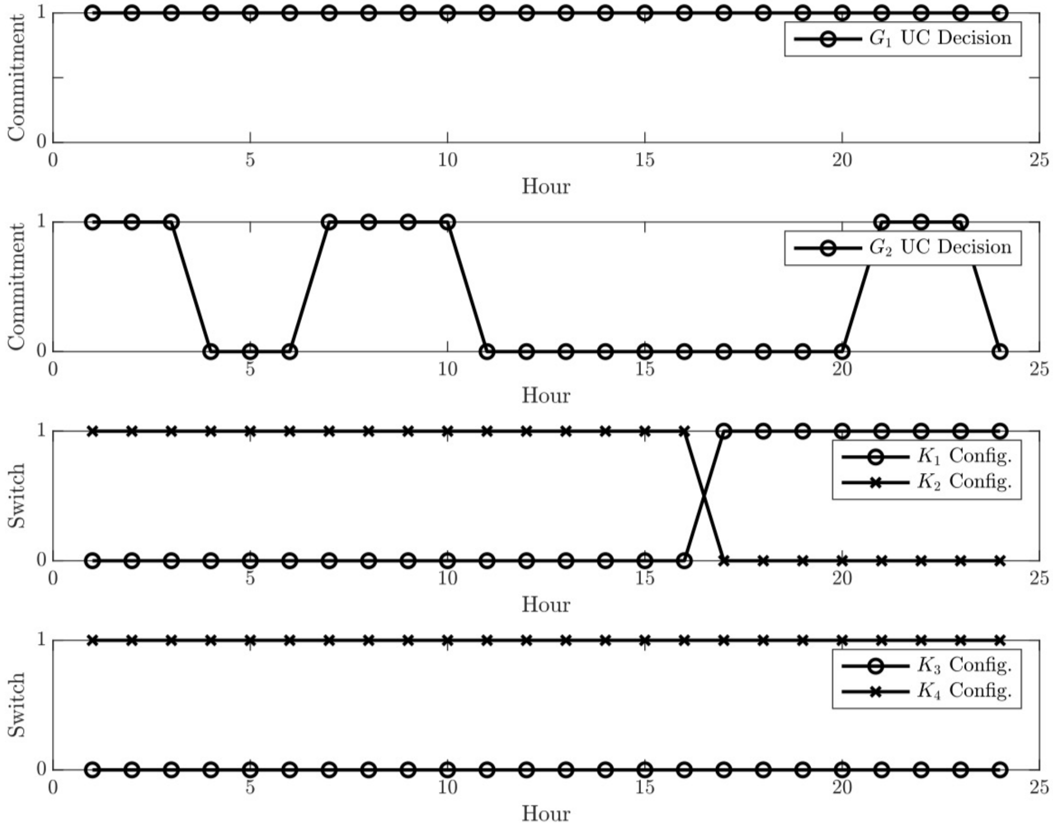


Δ : 5 scenarios for transmission network
10 & 12 scenarios for distribution networks

We perform a sensitivity analysis for testing different scenario number, and we found that the scenario set $10 \times \Delta$ can achieve good solution quality and balance the tradeoff between the computational complexity and the accuracy.

Test Case I: Tran6Dist7+9 (Cont'd)

- UC and Network Configuration Decisions



Several Observations:

- G1 opens all day due to its low generation cost and high capacity
- G2 opens mainly at night because there is few PV output at night.
- Switches change in hour 16 due to the peak load occurrence.

Test Case I: Tran6Dist7+9 (Cont'd)

- Comparison between coordination and independence.

$IUCED_1$	TS	Total Costs:	\$38,943.87
		ADN_1	ADN_2
	Power Mismatch	31.1%	37.8%
	Total Costs	\$4,324.82	\$5,609.71
	Received LMP	\$16.83/MWh	\$16.83/MWh
$IUCED_2$	TS	Total Costs:	\$27,835.94
		ADN_1	ADN_2
	Power Mismatch	5.8%	8.4%
	Total Costs	\$3,658.62	\$5,119.84
	Received LMP	\$15.47/MWh	\$15.47/MWh
$TDC-UCED$	TS	Total Costs:	\$28,294.12
		ADN_1	ADN_2
	Power Mismatch	0%	0%
	Total Costs	\$3,316.20	\$4,789.09
	Received LMP	\$14.73/MWh	\$14.73/MWh

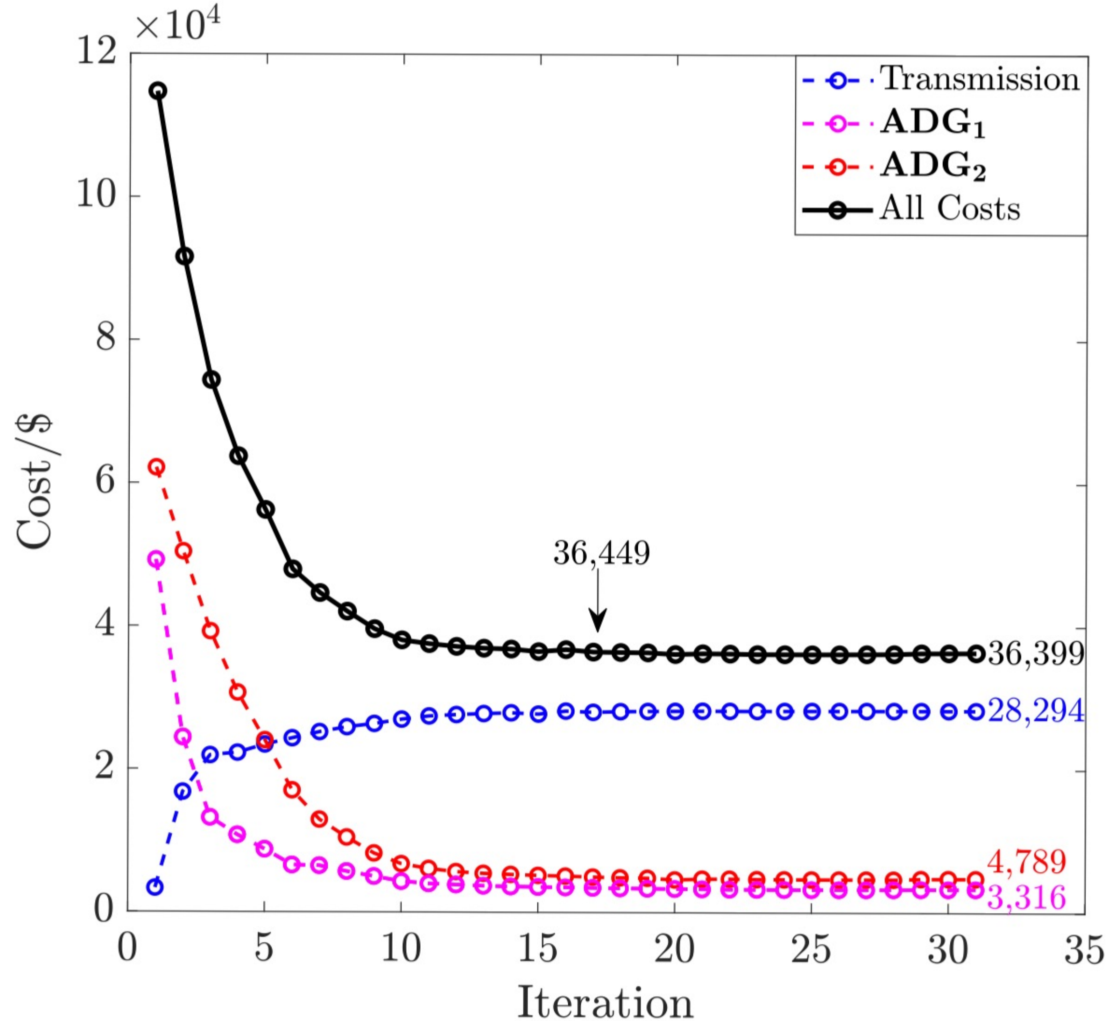
- $TDC-UCED$ means T-D coordinated UC&ED

Explanation:

- $IUCED_1$ means isolated UC&ED when transmission use the mean value of the overall distribution demand as boundary demand.
- $IUCED_2$ means isolated UC&ED when transmission use the total generation minus total demand of the distribution system as boundary demand.

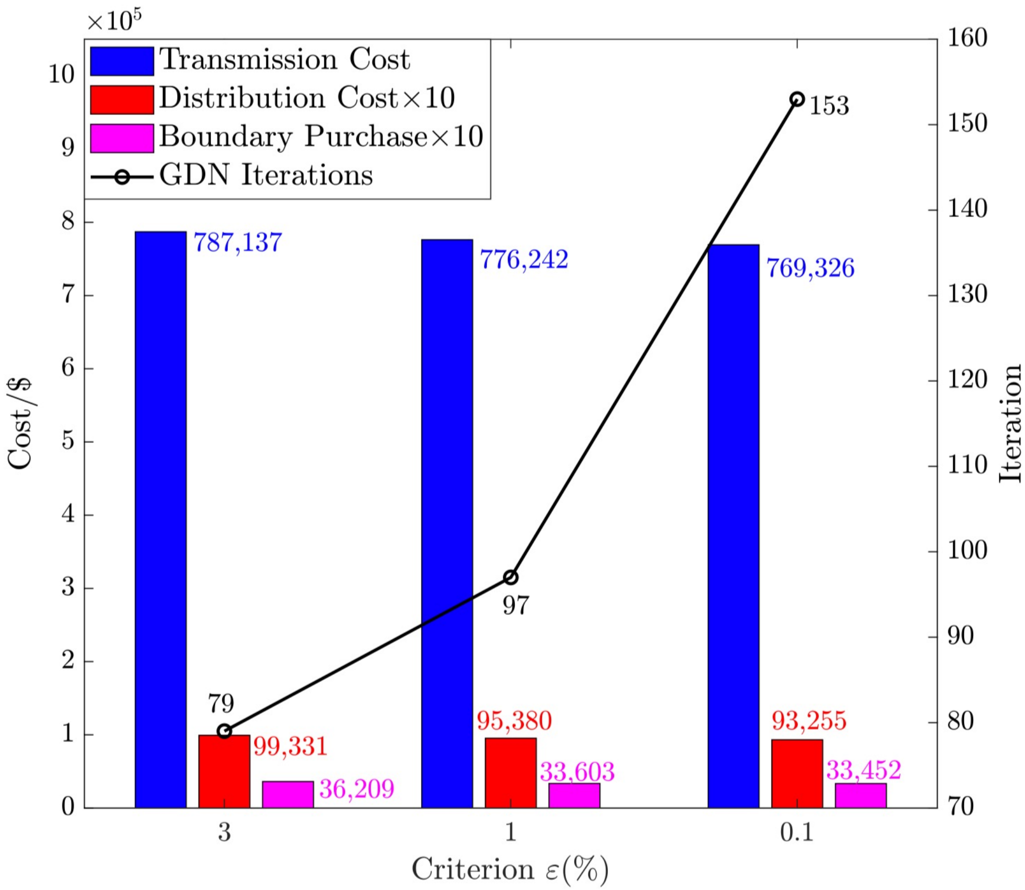
Test Case I: Tran6Dist7+9 (Cont'd)

- Since it is an optimality-conditioned algorithm, the convergence is fast at the beginning.
- We could conveniently select the convergence criterion to balance the tradeoff between the accuracy and computational efforts.



Test Case II: Tran30Dist34 (Cont'd)

- Algorithmic Performance under different stopping criteria



Explanation:

- Boundary purchase is calculated from multiplying the boundary LMP with the boundary power exchange.

Observation:

- Minor convergence improvement when iteration number goes high. Choice of stopping criterion is sensitive to the solving time.

Remarks

- A decentralized paradigm for the coordinated economic dispatch between transmission and distribution networks is proposed to increase the visibility of the distribution side for ISO and reduce boundary power mismatch.
- The enhancement of a nested L-shaped method efficiently decomposes and facilitates the distributed computation.

Outline

- Introduction and Background
- **Long-term Study**: System Planning towards 100% Renewable Penetration
- **Short-term Study**: Transmission and Distribution Coordinated Market Hierarchy
- **General Development**: Multi-timescale Market Coordination with New Designs
- Summary

Market Rule New Designs

- Ancillary service market
  - Ancillary services help maintaining the system reliability.
  - We focus on the frequency-related responses:
    - Primary frequency response
    - Regulation service
    - Spinning/non-spinning reserve
- New designs
  - Ancillary services provided by variable resources:
    - Renewable energy (PV-focused)
    - Energy storage

Frequency Responses

- Different system operators have different taxonomy of the frequency responses:

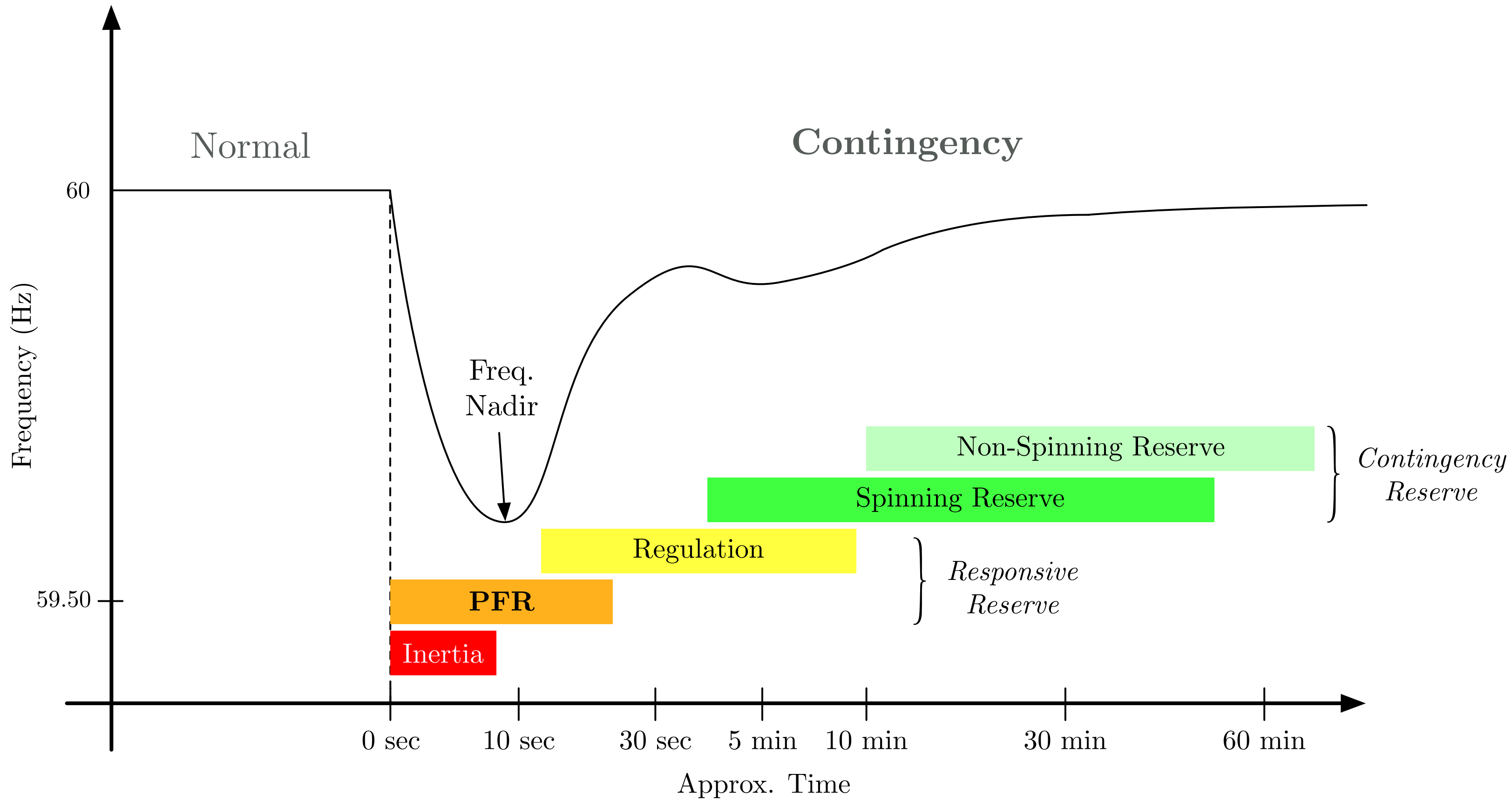
<table>
<tr><th>Electric System</th><th>Primary Regulation</th><th>Secondary Regulation</th><th colspan="3">Tertiary Regulation</th></tr>
<tr><td rowspan="3">PJM</td><td rowspan="3">Frequency Response</td><td rowspan="3">Frequency Regulation</td><td colspan="3">Operating Reserve</td></tr>
<tr><td colspan="2">Primary/Contingency Reserve</td><td rowspan="2">Secondary Reserve</td></tr>
<tr><td>Spinning Reserve</td><td>Quick Start Reserve</td></tr>
<tr><td rowspan="2">New-England</td><td rowspan="2">Frequency Response</td><td rowspan="2">Frequency Regulation</td><td colspan="3">Operating Reserve</td></tr>
<tr><td>Ten Minute Spinning Reserve TMSR</td><td>Ten Minute Non Spinning Reserve TMNSR</td><td>Thirty Minute Operating Reserve TMOR</td></tr>
<tr><td rowspan="3">Great Britain</td><td>Primary Response</td><td rowspan="3">Fast Reserve</td><td colspan="2">Operating Reserve</td><td rowspan="3">BM Start-Up</td></tr>
<tr><td>Secondary Response</td><td rowspan="2">Fast Start</td><td rowspan="2">Short Time Operating Reserve</td></tr>
<tr><td>High Frequency Response</td></tr>
<tr><td>Germany</td><td>Primary Reserve</td><td>Secondary Reserve</td><td colspan="3">Minutes Reserve</td></tr>
</table>

- The hierarchy of the frequency response is based on the responsive time.
- Frequency response has up service and down service.
- The fast responsive reserve is now provided and controlled by embedded electronic devices.

Source: V. Pandurangan et. al, "Frequency regulation services: A comparative study of select North American and European reserve markets", 2012 NAPS Proceeding, 2012.

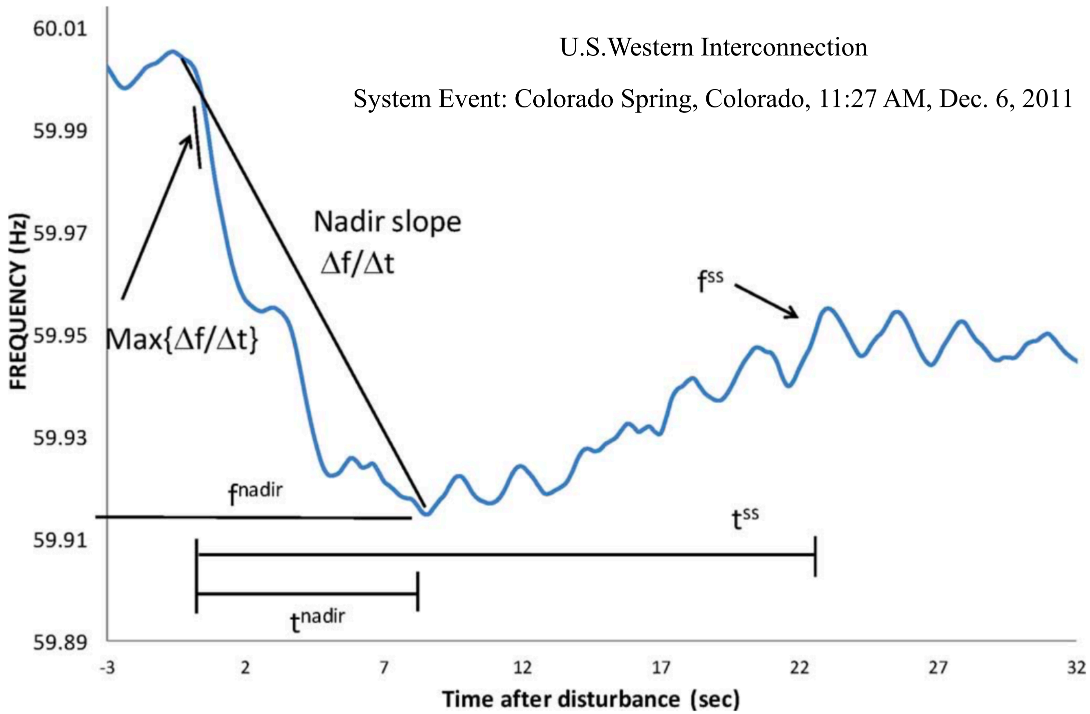
Frequency Responses (Cont'd)

- Responsive Time:



Primary Frequency Response (PFR)

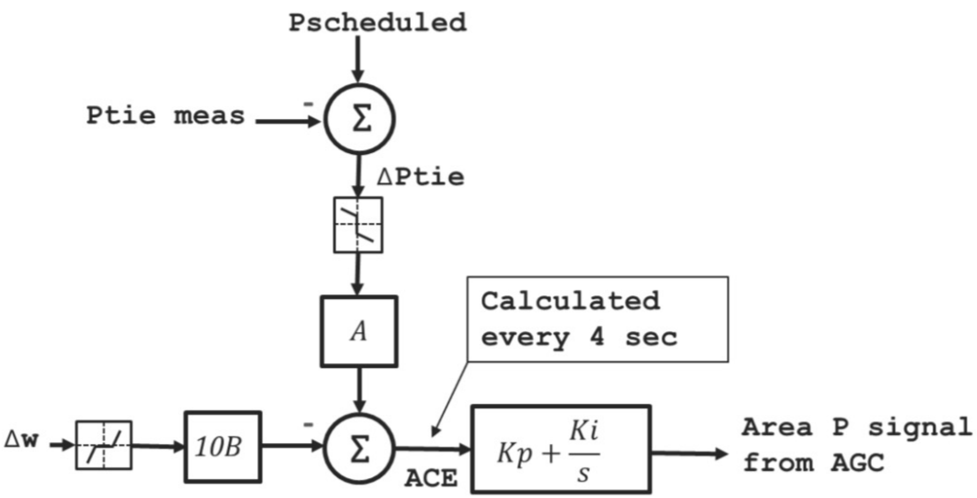
- A response from a resource that is automatically self-deployed and provides a full response within 30 cycles after frequency meets or drops below a preset threshold (from ERCOT).
- PFR threshold:
  - FFR1: 59.9Hz
  - FFR2: 59.8Hz
- PFR helps to stabilize the frequency in a second-level time interval when events occur.



*Source: E. Ela, et al, "*Market Designs for the Primary Frequency Response Ancillary Service—Part I: Motivation and Design", IEEE Trans. on Power Systems, 2014.

Automatic Generation Control (AGC)

- The purpose of AGC is to ensure that the actual MW output of an area is equal to the scheduled MW output of the area.
- AGC service is generally based on Area Control Error (ACE) and integrated into the energy market, called Regulation Market.
- AGC can help the frequency recover to the nominal frequency if possible. Area control error needs to be maintained in certain levels.



Spinning/Non-Spinning Reserves and Model

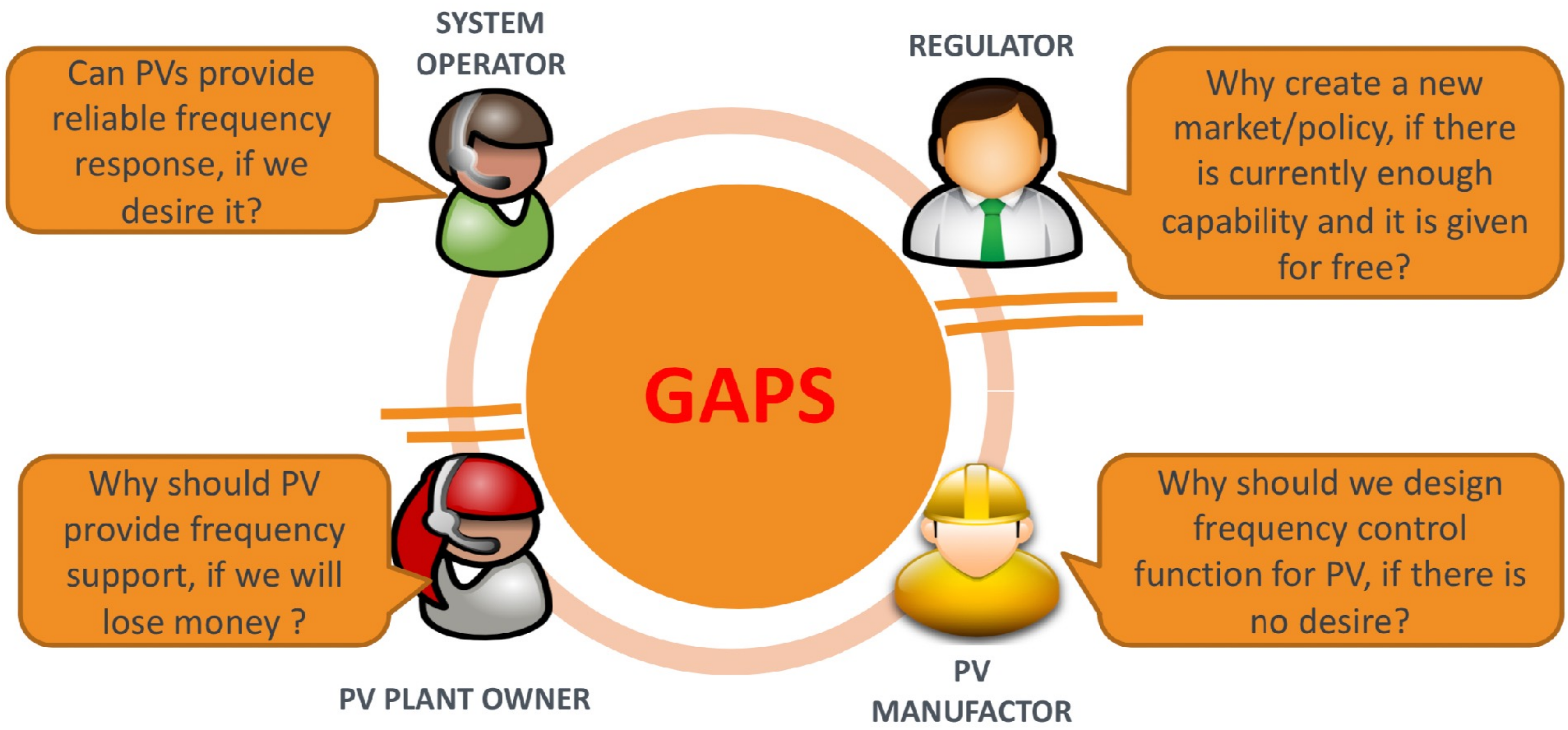
- Spinning/Non-spinning reserves are categorized into the contingency reserve.
- When a big system event occurs, PFR and AGC are not sufficient to pull the frequency back to the nominal, then the spinning reserve will be operated for it.
  - Spinning reserve: provided by online generators
  - Non-spinning reserve: prepared by offline generators
- Flexibility requirement:

$$\sum_i u_{i,t} * P_i^{\max} \geq \sum_d P_{d,t}^{load} + P_t^{spin}$$

New Sources of Frequency Responses?

- Currently, most of the frequency responses are covered by the synchronous generators.
- Can **renewables** and **storage** provide frequency response?
  - Yes, and with the similar strategy. However, since the wind, PV and energy storage do not have inherent inertia, virtual synchronous machine technology may need to be employed.
  - For modeling in the steady-state, as the droop curve can be virtualized, the system constraints for ancillary service provision remain the same.
  - Ancillary service can be covered by the inherent headroom of the renewables and energy storage. Hence the price of ancillary services can be highly decreased.

Motivation for AS provided by Renewables



Mathematical Model for Online Services

- PFR and AGC Model

$\Delta f^{\max}$	Max. freq. deviation
DB_g^{PV}	Gen. deadband
Ri_g^{PV}	Virtual droop eq.
RR_g^{PV}	Ramp rate
t_g^{rec}	Reaction time

$$0 \le PFR_{g,h}^{+,PV} \le \frac{\Delta f^{\max} - DB_g^{PV}}{Ri_g^{PV}},$$ physical limit

$$\underline{P}_g^{PV} \le P_{g,h}^{PV} + PFR_{g,h}^{+,PV} \le \overline{P}_g^{PV},$$ headroom

$$0 \le AGC_{g,h}^{+,PV} \le t_g^{\text{rec}} \cdot RR_g^{PV},$$ ramp limit

$$\underline{P}_g^{PV} \le P_{g,h}^{PV} + PFR_{g,h}^{+,PV} + AGC_{g,h}^{+,PV} \le \overline{P}_g^{PV},$$ headroom

$$0 \le AGC_{g,h}^{-,PV} \le t_g^{\text{rec}} \cdot RR_g^{PV},$$ ramp limit

$$\underline{P}_g^{PV} \le P_{g,h}^{PV} - AGC_{g,h}^{-,PV} \le \overline{P}_g^{PV},$$ downroom

- Spinning Reserve Model

$$0 \le Spin_{g,h}^{+,PV} \le t_g^{\text{rec}} \cdot RR_g^{PV},$$

$$\underline{P}_g^{PV} \le P_{g,h}^{PV} + PFR_{g,h}^{+,PV} + AGC_{g,h}^{+,PV} + Spin_{g,h}^{+,PV} \le \overline{P}_g^{PV}$$

All upward reserves share the same headroom.

All downward reserves share the same downroom.

Mathematical Model for Offline Services

- Non-spinning Reserve Model
  - Operation constraint

$$NonSpin^{+}_{g,h} \leq RR_g \cdot u_{g,h} + (1 - u_{g,h}) \cdot \left[\underline{P}_g + RR_g \cdot \max(0, t^{rec}_{g,NS} - SUtime_g)\right]$$

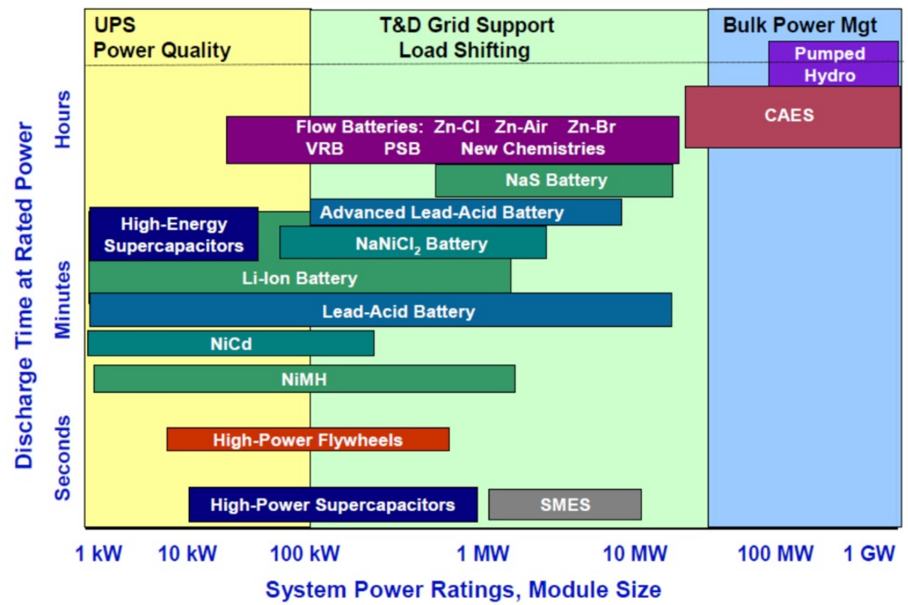
  - An hourly constraint regulates that during the startup/shutdown process the unit cannot provide non-spinning reserves.

$$NonSpin^{+}_{g,h} \leq (1 - SU_{g,h+1}) \cdot RR_g \cdot t^{rec}_{g,NS}$$
$$NonSpin^{+}_{g,h} \leq (1 - SD_{g,h+1}) \cdot RR_g \cdot t^{rec}_{g,NS}$$

  - Idea: Units with startup time larger than the non-spinning reserve reaction time cannot provide the non-spinning reserve.

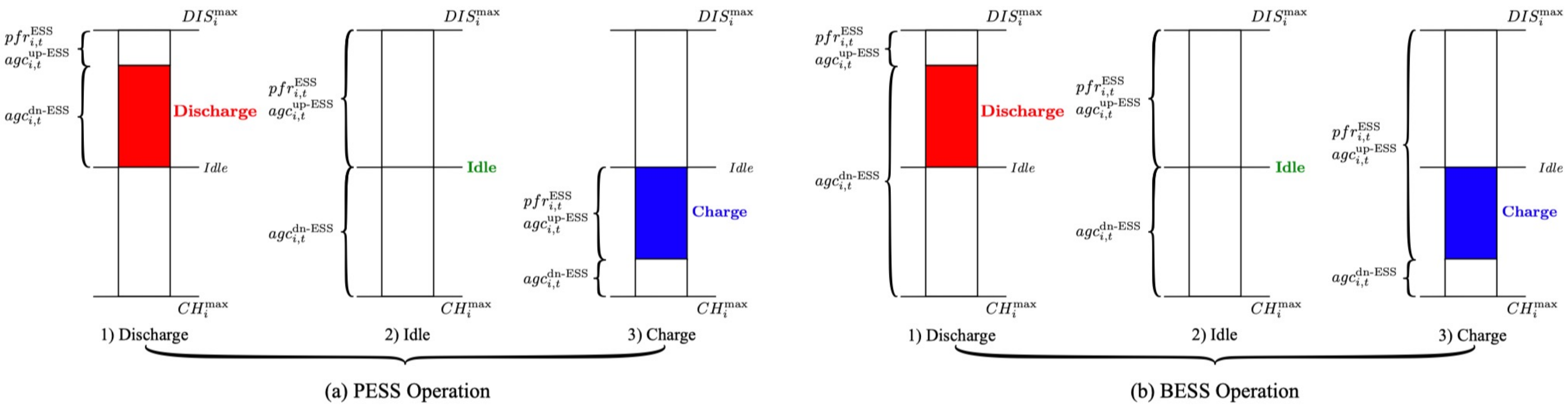
AS provided by Energy Storage

- The flexibility type of energy storage needs to be differentiated when designing the operation schemes of ESSs. Low-flexibility type ESSs such as the pumped hydro energy storage (PESS) take hours to change from charging to discharging while high-flexibility type ESSs such as the battery energy storage (BESS) may only need seconds or minutes.



ESS technology comparison*

AS provided by Energy Storage (Cont'd)



- Based on ESS flexibilities, the headroom for upward reserves and dispatch for downward reserves would be different.
- For PESS units, it takes extra time to pump. The headroom is limited in the same direction of the current status.
- For BESS units, it is more flexible to change status. The headroom could exceed the current direction.

Mathematical Model for ESS

- PESS Model

$$pfr_{i,t}^{\text{ESS}} + agc_{i,t}^{\text{up-ESS}} \leq (1 - c_{i,t}) \cdot DIS_i^{\max} + ch_{i,t} - dis_{i,t}, \tag{2a}$$

$$agc_{i,t}^{\text{dn-ESS}} \leq (1 - d_{i,t}) \cdot CH_i^{\max} + dis_{i,t} - ch_{i,t}. \tag{2b}$$

- BESS Model

$$pfr_{i,t}^{\text{ESS}} + agc_{i,t}^{\text{up-ESS}} \leq DIS_i^{\max} + ch_{i,t} - dis_{i,t}, \tag{3a}$$

$$agc_{i,t}^{\text{dn-ESS}} \leq CH_i^{\max} + dis_{i,t} - ch_{i,t}. \tag{3b}$$

- Notations

$c_{i,t}$ / $d_{i,t}$	Charging/discharging status of ESS i at t
$ch_{i,t}$ / $dis_{i,t}$	Charging/discharging power of ESS i at t
$CH_i^{\max}$	Maximum charging limit for ESS i
$DIS_i^{\max}$	Maximum discharging limit for ESS i

- General Formulations

$$c_{i,t} + d_{i,t} \leq 1,$$
$$ch_{i,t} \leq c_{i,t} \cdot CH_i^{\max},$$
$$dis_{i,t} \leq d_{i,t} \cdot DIS_i^{\max},$$
$$\ldots\ldots$$

We consider charge/discharge/ idle statuses for ESS

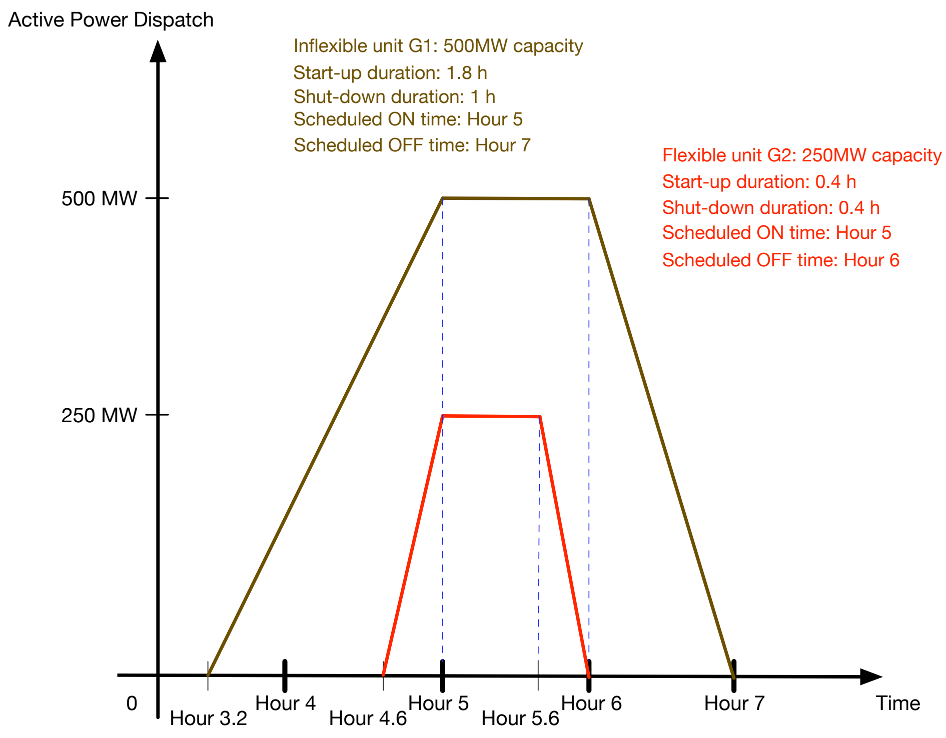
General Model: Generation Formulation

Objective: To Min. unit. costs + ancillary service costs
The generation cost function is modeled as a piece-wise function of power.
Constraint Description:
[P1] Every generator should follow **logic constraints** on ON/OFF status and STARTUP/SHUTDOWN actions.
[P2] Every generator should follow **MINON/MINOFF time** constraints.
[P3] Every generator should follow **capacity** constraints for every period.
[P4] Every generator should follow **ramp rate** constraints.
[P5] Every generator should follow PFR, AGC and spinning reserve constraints.
[P6] System PFR, AGC and spinning reserve requirement.
[P7] Every line should follow the Power Flow Equations.

constraints only apply in UC program.

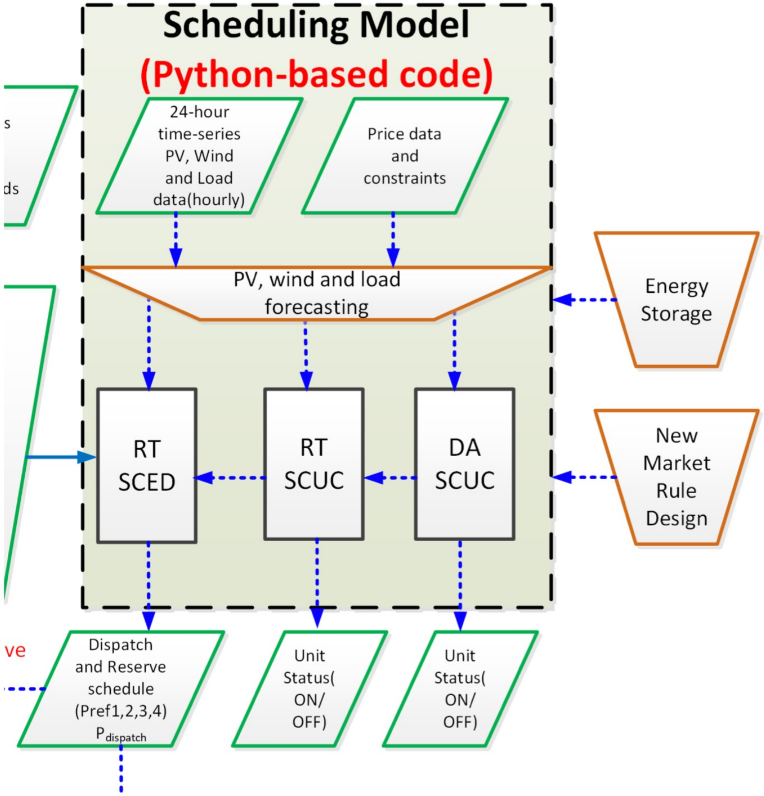
Build Generator Trajectories

- In real world, synchronous generators require start-up time and shut-down time to perform turn-on and turn-off.
- We differentiate generators by their trajectory time to ***flexible units***, ***inflexible units*** and ***renewable units***.
- The inflexible units' trajectories are modeled in the DAUC, and the flexible units' trajectories are modeled in the RTUC.
- During trajectory, the generator **cannot** provide any frequency response.

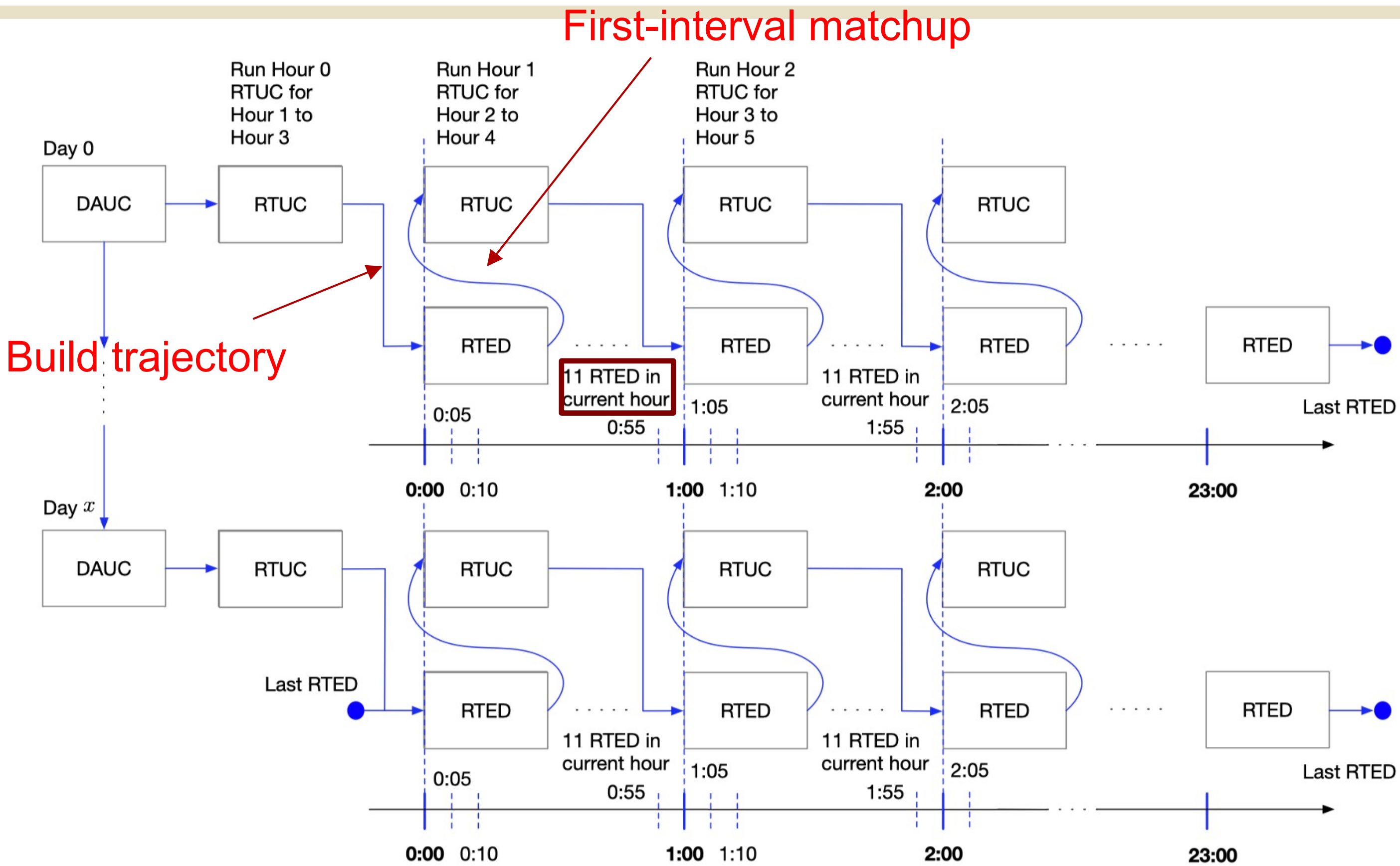


Framework Overview

- The multi-timescale framework includes:
  - Day-ahead unit commitment (DAUC)
  - Real-time unit commitment (RTUC)
  - Real-time economic dispatch (RTED)
- The steady state should prepare:
  - Generator and ESS setpoints
  - Dynamic PFR, AGC and spinning reserve schedules
  - Transmission line loss



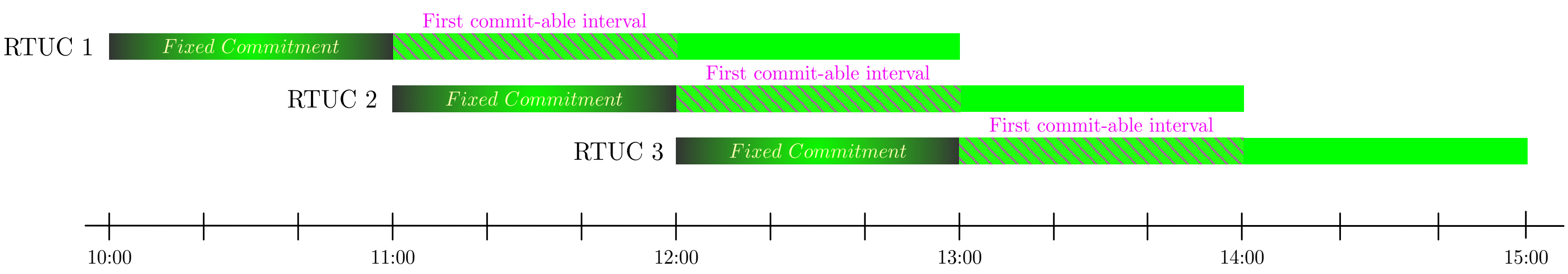
Multi-timescale Coupling



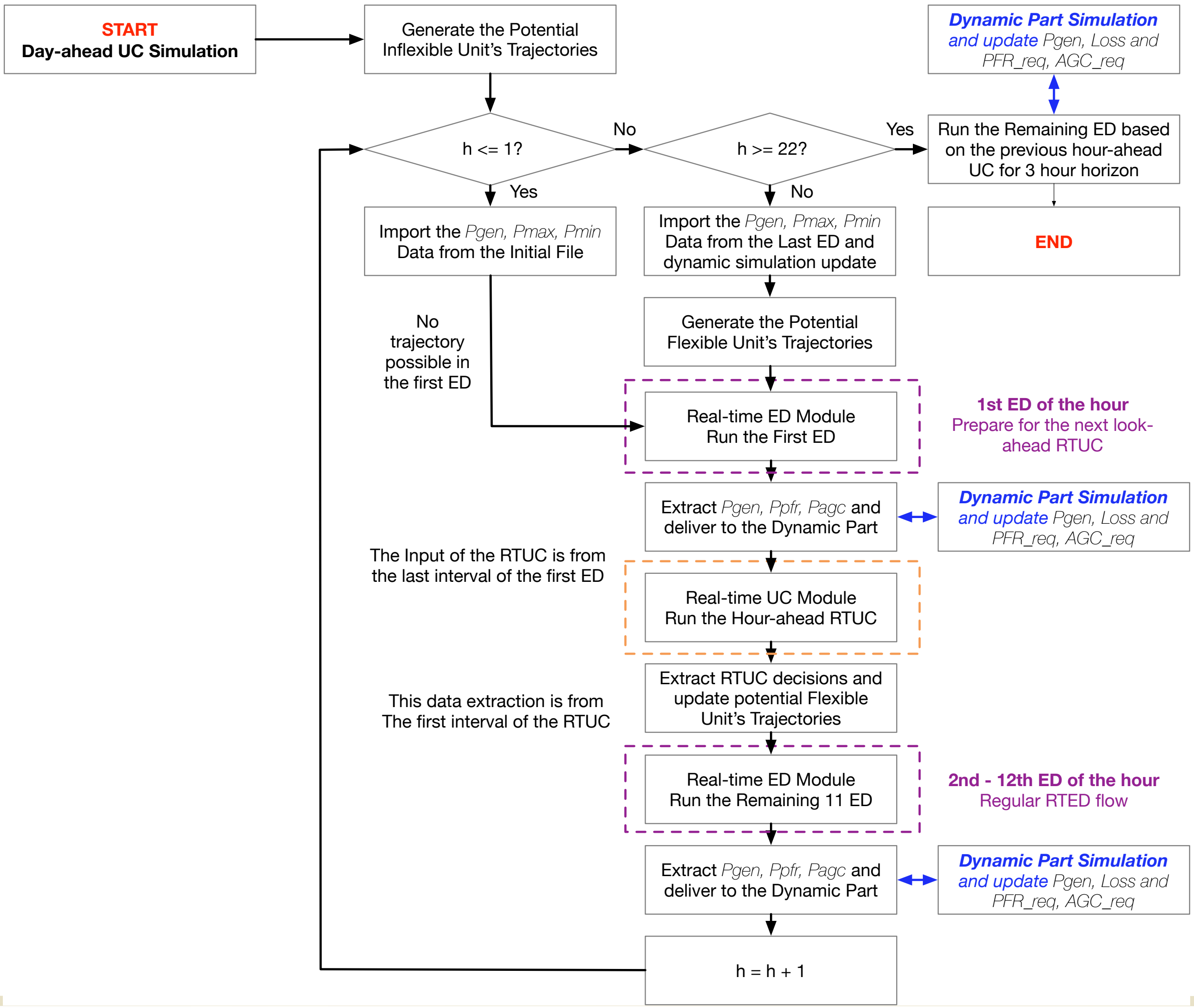
At the beginning of every hour, run a look-ahead RTED with 12 intervals (every 5 minutes).
After the DAUC is executed, the whole-day RTUC + RTED will be executed before the next-day DAUC.
The last interval results of the last interval RTED in one hour will be sent to the RTUC for the initial status of the hour-ahead RTUC.
The RTUC commitment results will be used for the next-hour RTED.
Next-day DAUC uses current DAUC results as inputs.
The first-interval RTED in the next day uses the last-interval RTED result in the current day as inputs.
The first interval (current interval) results of the RTED will be sent to dynamic simulations.

New Logic: Fixed-interval RTUC

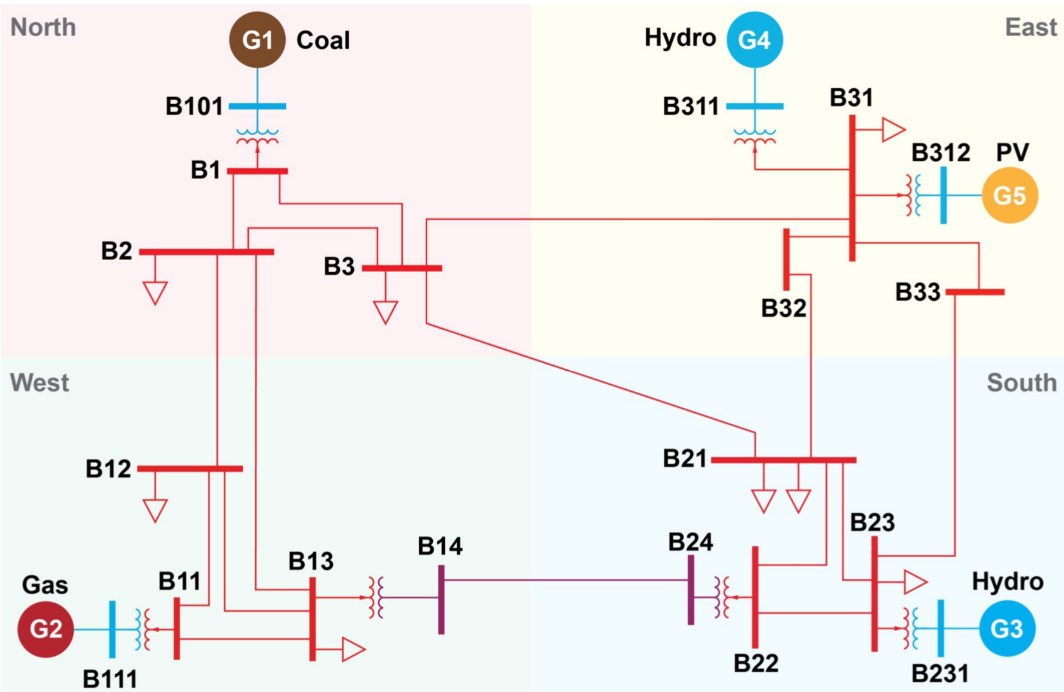
- Since RTUC is also a rolling-horizon operation, the operator will update the startup/shutdown statuses in the most recent RTUC. Hence, if the current RTUC changes the startup decision determined in the last RTUC, the non-spinning reserve scheduled in the last RTUC will violate the startup logic.
- the first interval's commitment is fixed by the second interval's commitment in the last RTUC. The first interval's commitment of each RTUC is consistent in any connecting period and hence will not violate the last RTUC's startup decisions.



Dynamic Coordination Flowchart



Case Studies I: Only PV in the System



Energy price of generators:

G5(PV) < G3(Hydro)

< G4 (Hydro) < G3 (Gas)

< G1 (Coal)

	PV provide frequency response	PV provide no frequency response
Low Solar (10% Pen)	Case 1	Case 4
Med Solar (50% Pen)	Case 2	Case 5
High Solar (80% Pen)	Case 3	Case 6

PFR Requirement Quantification

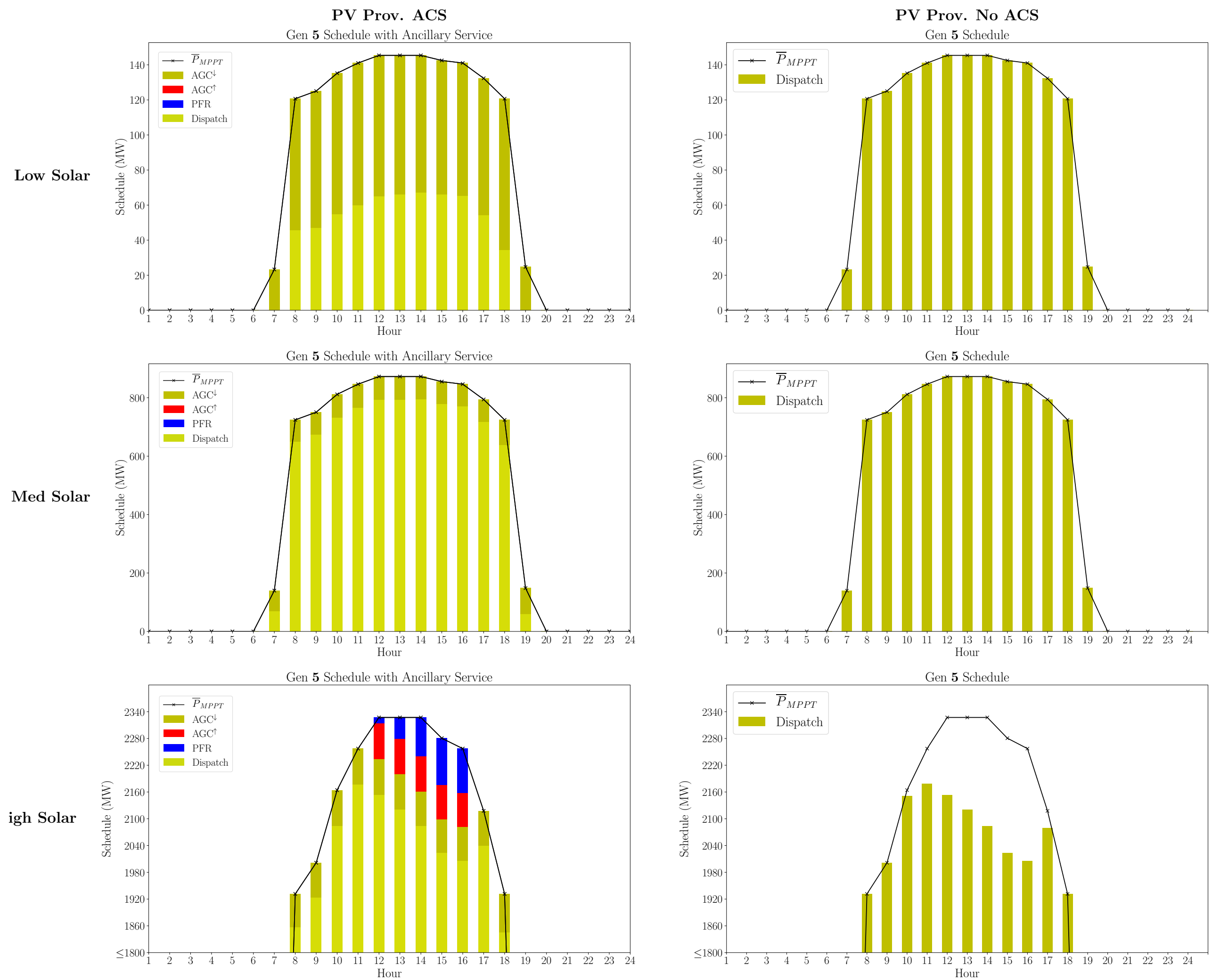
- Assumption: **Linear relationship between the PFR and the system inertia.**
- If we are given a 1% PFR requirement under 5% PV penetration, we can approximate the system PFR requirement based on the linear increase of the PV penetration as follows.

Since PV cannot contribute to the system inertia, increasing PV penetration will reduce the system inertia. Using 5% PV penetration as a baseline, the system currently has 95% inertia. If we increase the PV penetration to 60%, for example, the system has 40% inertia. Then, based on the baseline 1% PFR requirement and the linear relationship between PFR and inertia, we can calculate the PFR requirement under 60% penetration as:

$$PFR_{\mathrm{req}}^{60\%} = \frac{100\% - 5\%}{100\% - 60\%} \cdot 1\% = 2.375\%$$

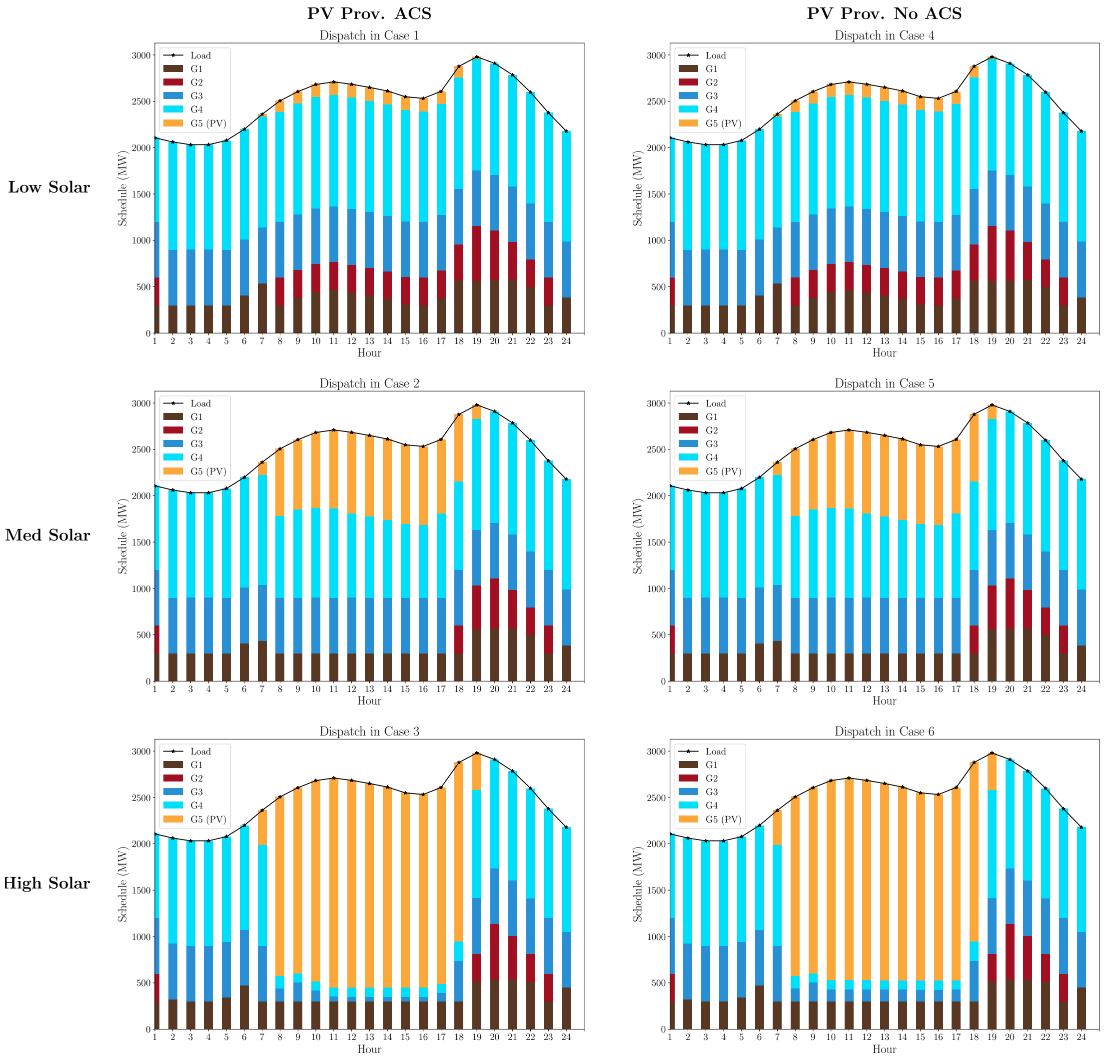
Case Studies: Day-ahead Operation

- PV's Dispatch
- PV is always ON due to the zero marginal cost, and in high solar cases (Case 3 and Case 6), PV can have headroom to provide regulation up and PFR up services.



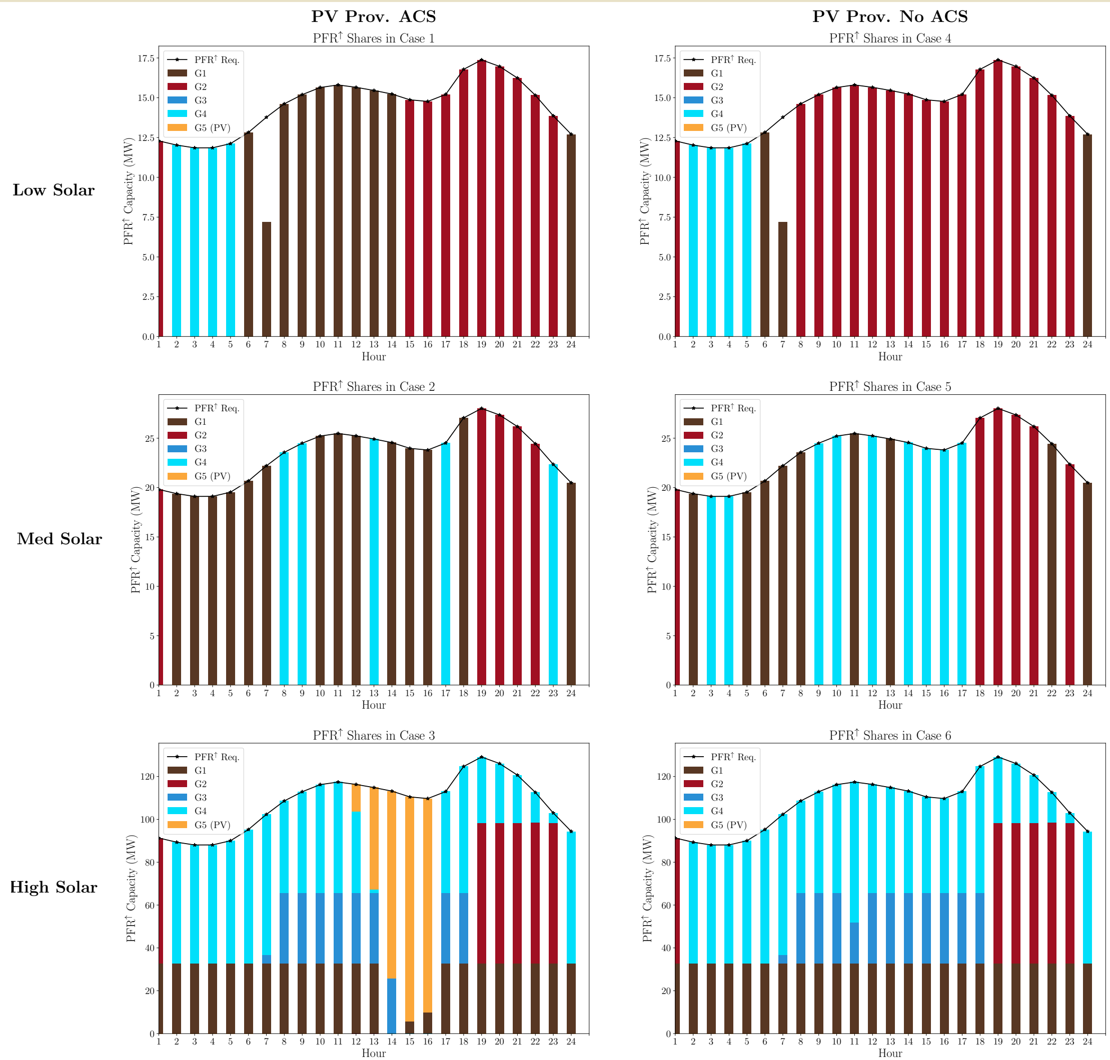
Case Studies I: Day-ahead Operation (Cont’d)

- Dispatch Share between generators
- PV pushes down the cheapest units G3 and G4 to their minimum generation levels.
- During peak load time, the gas unit and coal unit schedule more energy



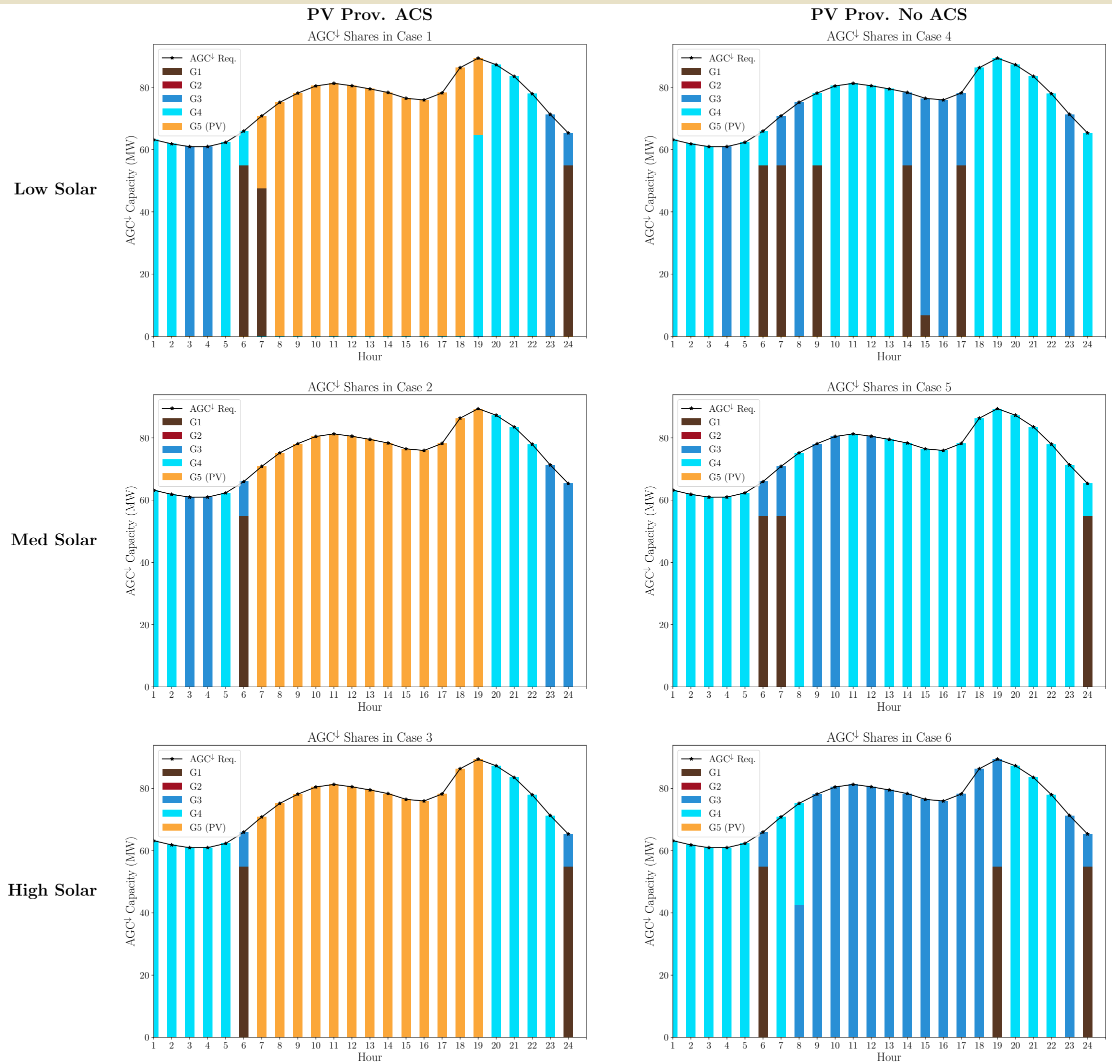
Case Studies I: Day-ahead Operation (Cont'd)

- PFR provided by generators
- PV can only provide PFR in the high solar case (Case 3), since other cases give PV no headroom.



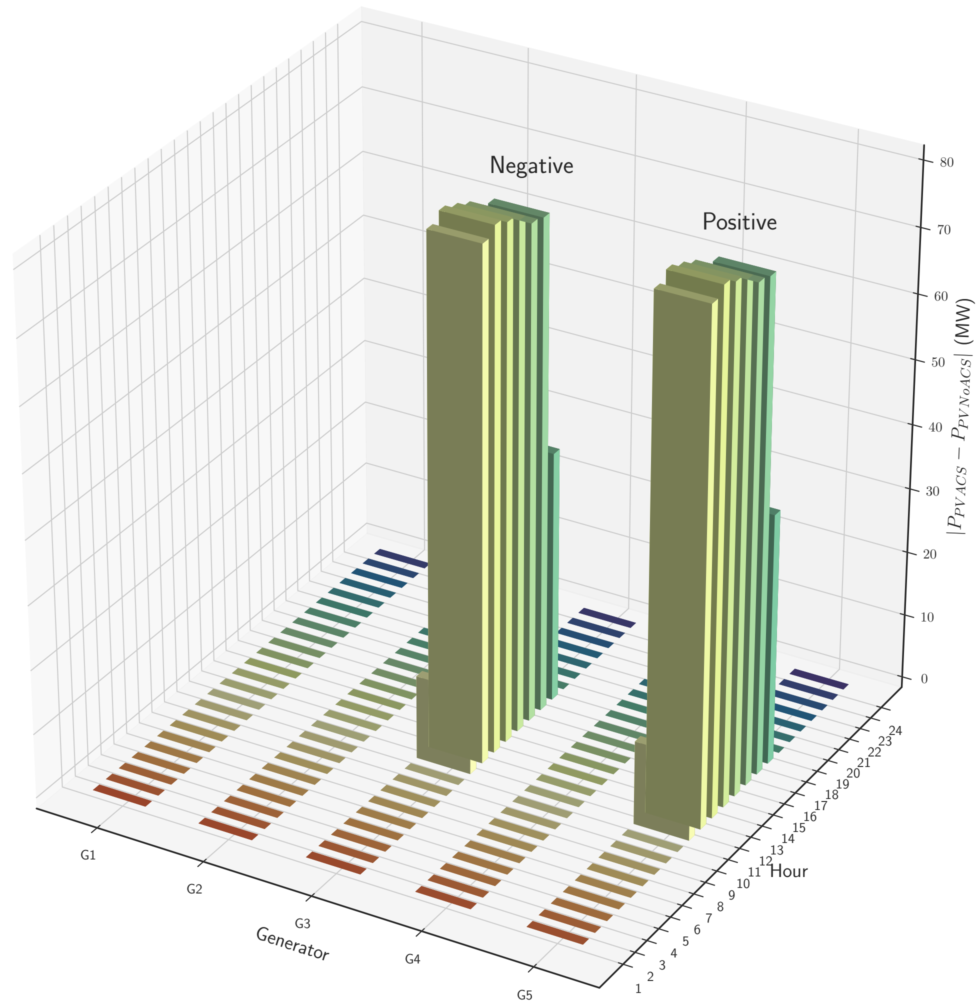
Case Studies I: Day-ahead Operation (Cont'd)

- Regulation-down provided by generators
- The regulation-down services are the most redundant service since every generator can schedule down the output to meet the requirement.



Case Studies I: Day-ahead Operation (Cont'd)

- Dispatch difference between Case 3 and Case 6 (High Solar)
- Since G3 is the second cheapest unit, so the discrepancy caused by PV is matched up by it.



Case Studies I: Day-ahead Operation (Cont'd)

- Cost comparison between Case 3 and Case 6 (High Solar)

	Case 3: PV provides AS	Case 6: PV provides no AS
Total Energy Cost	$309104.53 ↓	$313351.97
Ancillary Service Cost	$61.98	$61.98
PV Revenue	$19062.04 ↑	$12354.97

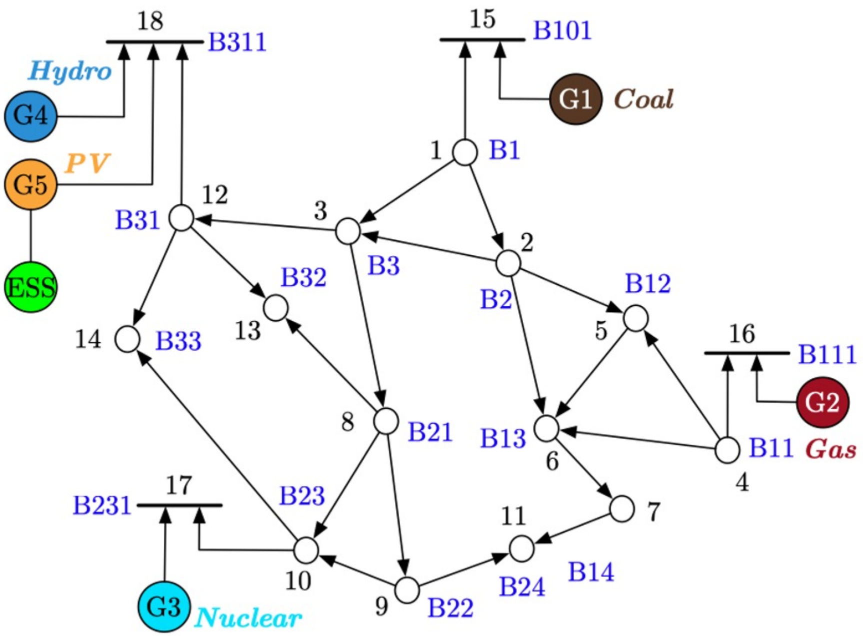
- PV's participation in the AS market still slightly reduces **the total energy cost** of the system.
- The PFR and regulation-up services are potential to be provided by PVs when PV is curtailed.
- PV can make additional revenue by providing ancillary services. When the PV penetration grows, PV's capability of providing AS also increases, as well as the revenue.

Sensitivity Analysis on PV Penetration Levels

- Total system cost under different PV penetration levels

PV penetration	PV can provide AS	PV cannot provide AS
5%	$ 289044.55	$ 295636.87
12.5%	$ 265543.79	$ 312568.23
20%	$ 248766.93	$ 345543.78
27.5%	$ 236978.76	$ 358732.89
35%	$ 233218.65	$ 377289.67
42.5%	$ 230123.86	$ 401765.84
50%	$ 227013.04	$ 427036.65

Case Studies II: PV+ESS in the System



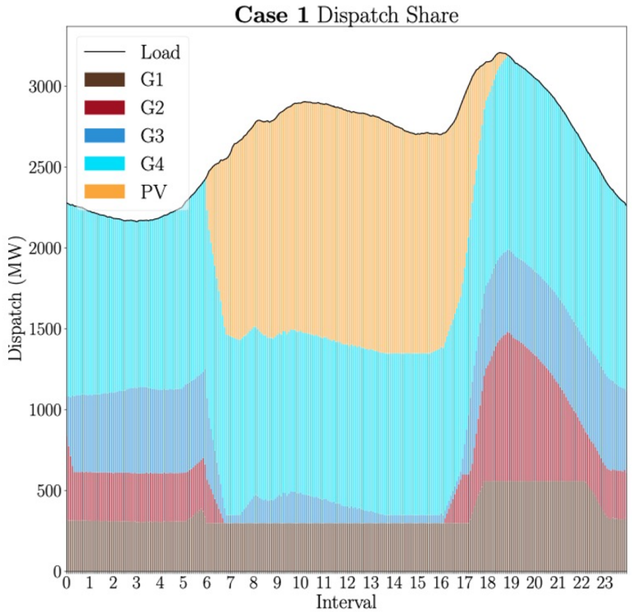
	ESS Capacity	Maximum SOC	Minimum SOC	Ch./Dis. Efficiency	Maximum Charge
ESS	1500 MWh	100%	6.6%	98%	300 MW
	Maximum Disharge	Initial Discharge	Initial SOC	Ramp rate	SOC loss rate
ESS	300 MW	150 MW	80%	50 MW/min	0

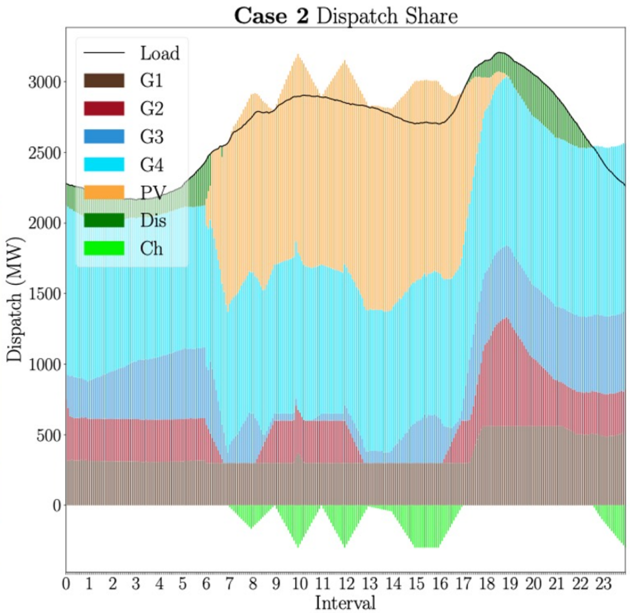
- Case 1: No ESS is installed.
- Case 2: The ESS is installed but cannot provide ancillary service.
- Case 3: The ESS is installed and can provide ancillary services with the low flexibility as PESS.
- Case 4: The ESS is installed and can provide ancillary services with the high flexibility as BESS.

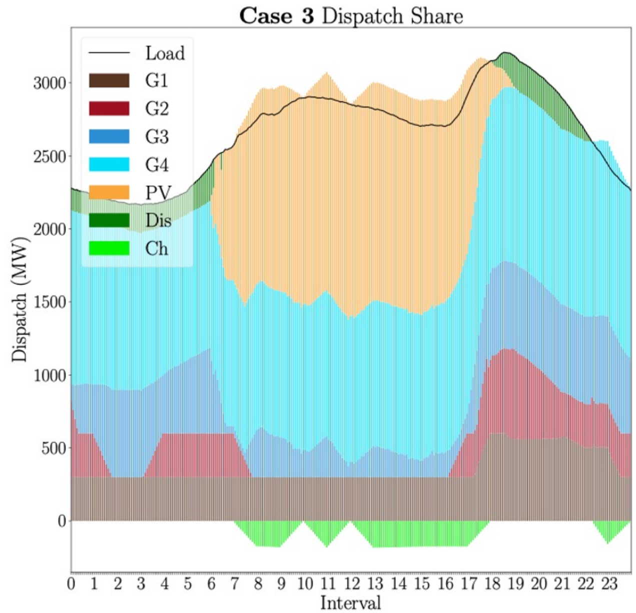
Case Studies II: Dispatch Results

- The optimized schedule of the RTED tells that the ESS gets charged in the daytime because the PV is abundant, and it is discharged in the peak load time when the PV power falls off.

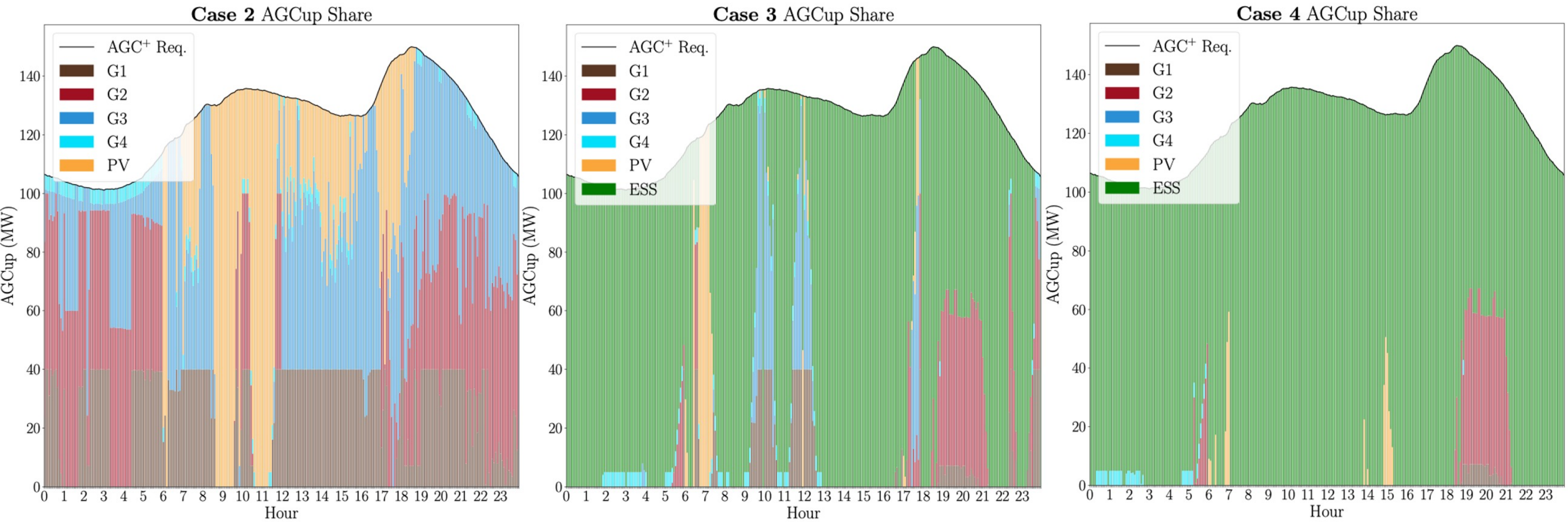
	Case 1	*Case 2*	*Case 3*	*Case 4*
Total Cost ($)	293,473	269,008	256,407	255,399
PV Curtailment (MWh)	215.20	9.74	0	0
Highest LMP ($)	13.74	13.74	13.82	13.82







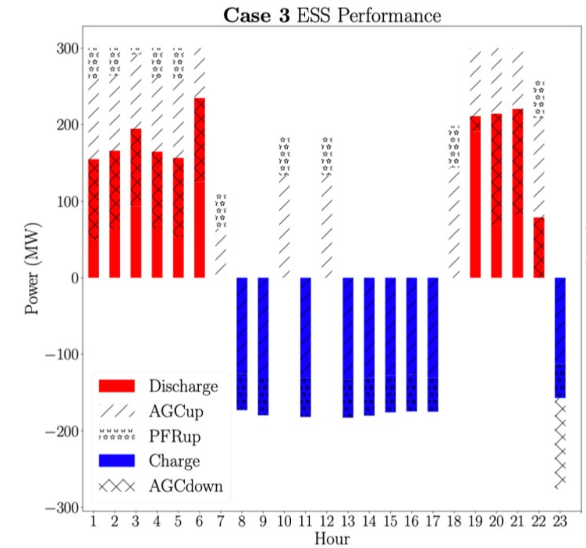
Case Studies II: Upward Reserve Results

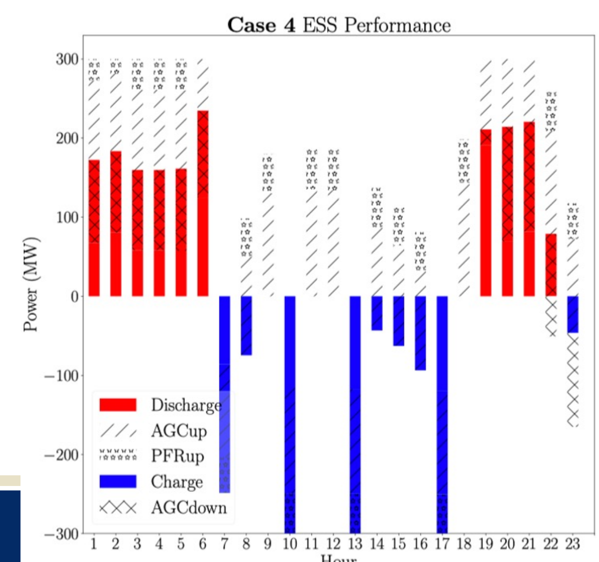


- When ESSs cannot provide ASs, generators reserve the headroom especially the marginal unit G2. Because the PV unit can use its curtailed power to provide AGC-up, PV and G2 are two main providers of AGC-up in Case 2.
- the ESSs gain a huge advantage of providing AGC-up in that their high flexibilities render a much lower opportunity cost of providing such services. When the ESS becomes more flexible, it can cover even most of the AS provision.

Case Studies II: Upward Reserve Results

- The ESS in Case 4 can cover more ASs than the ESS in Case 3 as it can provide ASs by exceeding its opposite limits, because of its higher flexibility of switching conditions.
- The exactness of the proposed ESS operating schemes is validated, which gives a reason for the lower cost of Case 4 in the cost table. Hence, system operators should consider the difference in ESS flexibilities during market operations.





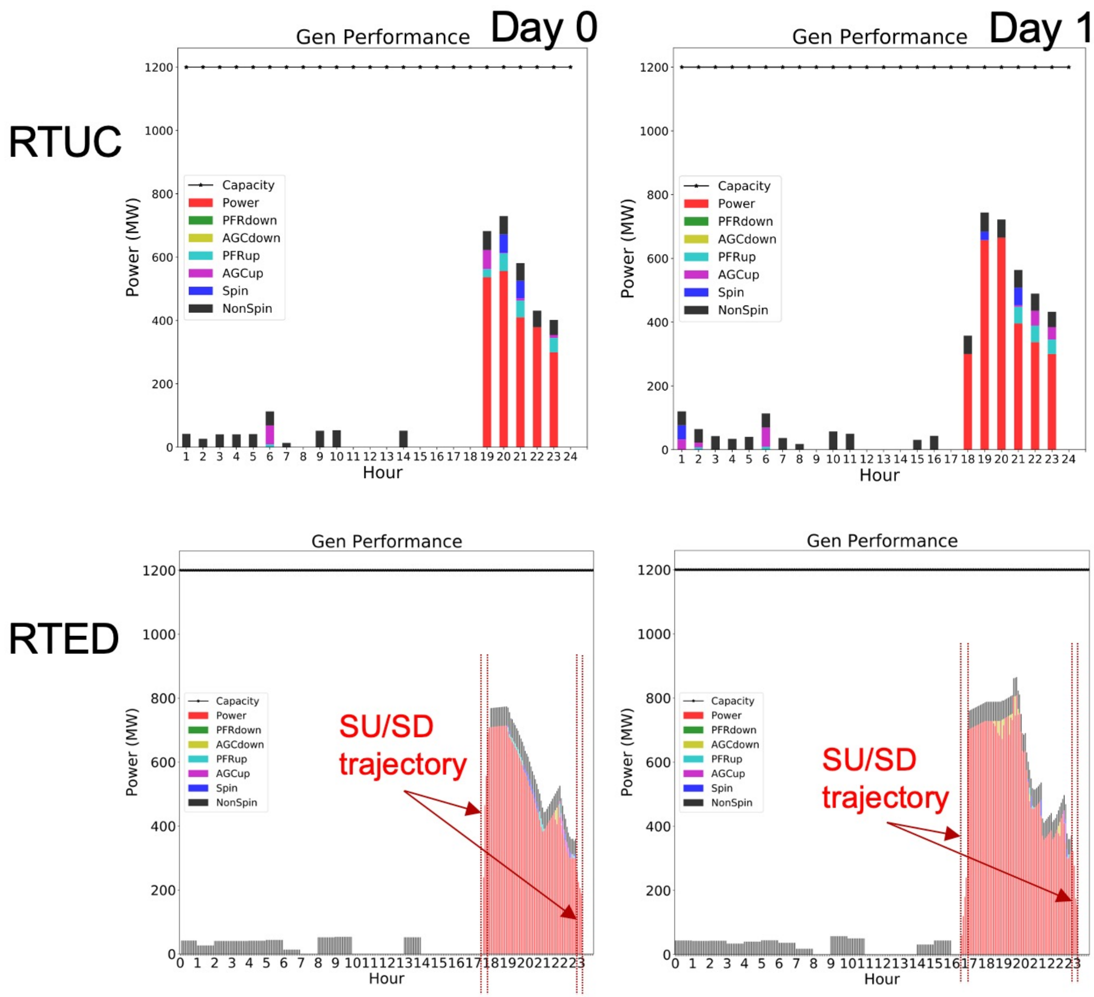
Sensitivity Study: Costs and Remarks

- Increasing ESS's size can reduce the system cost nearly in a linear manner, since the larger ESS is used, more generators can be shut down.
- Using larger ESS can help the system accommodate more PV generation as the PV curtailment is reduced.

SOC_Max (MWh)	Ch_Max/ Dis_Max (MW)	Total Cost ($)	Total PV Curtailment (MW)
0	0	274,100	265.804
400	50	268,286	100.884
600	100	261,948	8.095
800	150	243,571	0
1000	200	240,315	0
1200	250	237,121	0
1500	300	233,947	0
1600	350	211,832	0
1800	400	208,477	0

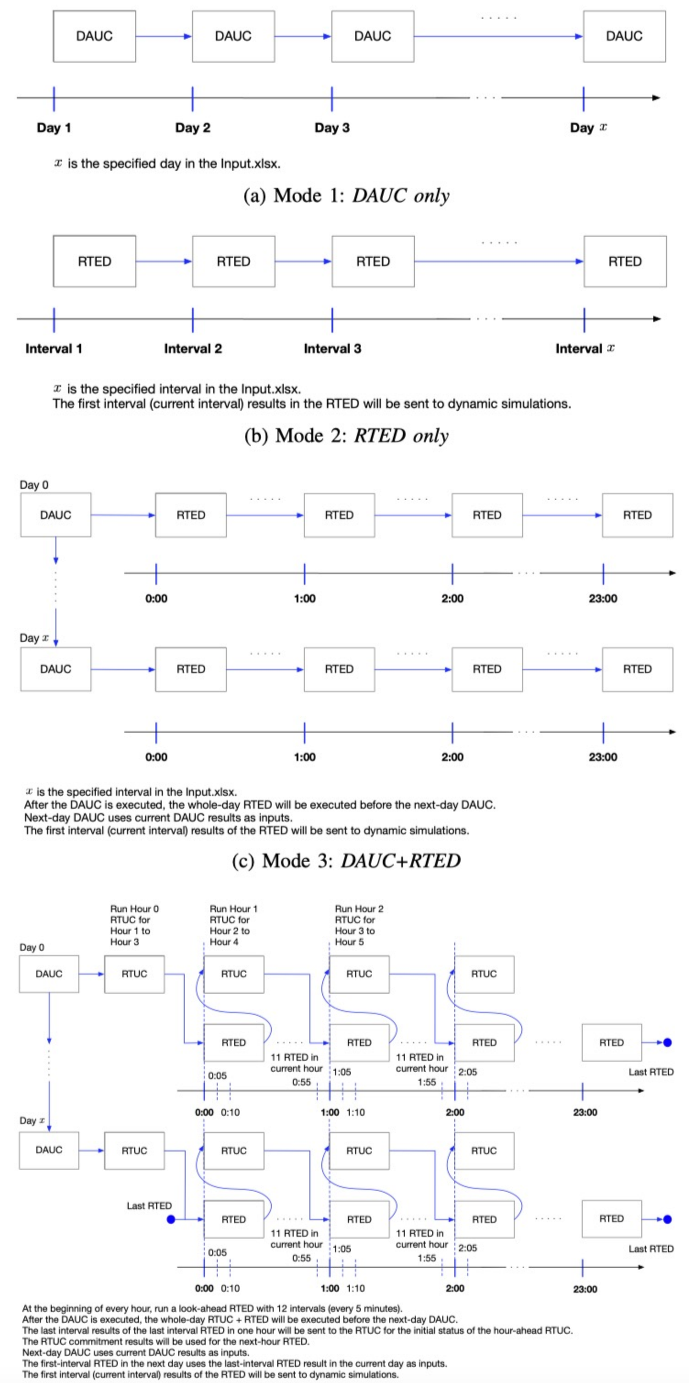
Case Studies II: G2's Performance

- G2 is most likely to provide the non-spinning reserve among all generators due to its flexibility and higher cost, creating more potential headroom for this unit.
- Since G2 has startup time < non-spinning reserve reaction time, it can provide it when offline. When online, it can also provide the non-spinning reserve. In RTED, during the startup/ shutdown trajectory, no unit can provide any type of reserve product, which is also evident in this figure.



The Development on Simulation Platform

- To better let industry and academic partners use our designs or perform market simulations, we develop a simulation platform including four modes:
  - Mode 1: DAUC only
  - Mode 2: RTED only
  - Mode 3: DAUC+RTED
  - Mode 4: DAUC+RTUC+RTED



(a) Mode 1: *DAUC only*

(b) Mode 2: *RTED only*

(c) Mode 3: *DAUC+RTED*

(d) Mode 4: *DAUC+RTUC+RTED*

User-friendly Code Execution and Output

- It is convenient to import the MIDAS-Scheduling package and execute the four modes.
- We provide detailed utility functions for the data preprocessing, postprocessing, result summary, result plotting.
- Users can also conveniently customize the operation models, revise constraints, and change attributes.

```
In [1]: from midass.operation.mode1 import run_mode1
        from midass.operation.mode2 import run_mode2
        from midass.operation.mode3 import run_mode3
        from midass.operation.mode4 import run_mode4
```

```
In [2]: results_mode1 = run_mode1(solver_name = "gurobi",
                                  prefix_dir = r"midass/operation/data/18_bus/",
                                  verbose = True)
```

```
In [2]: results_mode1 = run_mode1(solver_name = "gurobi",
                                  prefix_dir = r"data/18_bus/",
                                  verbose = False)

        ----------------- Start MIDAS Scheduling ---------------------

        -------------- Mode 1 --------------------
        -------------- Preprocessing...
```

```
In [4]: results_mode2 = run_mode2(solver_name = "gurobi",
                                  prefix_dir = r"data/18_bus/",
                                  psse_folder = r"18_bus_PSSE/",
                                  case_name = r"Case1",
                                  run_name = r"Case1_24hr_run_1_CL",
                                  close_loop_flag = False,
                                  ess_dispatchable = False,
                                  verbose = True)
```

```
------- Congrats! No penalty exists.
  RTED --------------------- Day 0 Interval 21 Objective value: 13962.219125928328
Energy cost: 13962.219125928328
Reserve cost: 0.0
------- Congrats! No penalty exists.
  RTED --------------------- Day 0 Interval 22 Objective value: 13959.56985733833
Energy cost: 13959.56985733833
Reserve cost: 0.0
------- Congrats! No penalty exists.
  RTED --------------------- Day 0 Interval 23 Objective value: 13958.206863349995
Energy cost: 13958.206863349995
Reserve cost: 0.0
------- Congrats! No penalty exists.
  RTED --------------------- Day 0 Interval 24 Objective value: 13956.408393510832
Energy cost: 13956.408393510832
Reserve cost: 0.0
------- Congrats! No penalty exists.

----------------- End MIDAS Scheduling -----------------
```

Remarks

- We propose new designs for the short-term electricity market operation, especially on the ancillary service market. Renewable energy and energy storage possess a huge potential to participate in the market.
- Both the renewable and energy storage should consider their physical limits when providing frequency response. The energy storage needs to take the flexibility type into account.
- We develop a simulation platform, which can be flexibly configured to various practical simulation scenarios. It can be employed by both industry partners and academic researchers to conduct further research on the market design and development.

Outline

- Introduction and Background
- **Long-term Study**: System Planning towards 100% Renewable Penetration
- **Short-term Study**: Transmission and Distribution Coordinated Market Hierarchy
- **General Development**: Multi-timescale Market Coordination with New Designs
- Summary

Summary

- This work conducts comprehensive research on the electricity market designs and operations, spanning from the long-term planning to the short-term operation, considering impacts of the growing renewable penetration.
- For the <u>long-term planning</u>, we discuss cases up to 100% renewable penetration with practical considerations on the economic assessment.
- For the <u>short-term operation</u>, we propose a new model for the transmission-distribution coordination with an accelerated solution algorithm on the hierarchical unit commitment problem.
- For <u>general development</u>, we design new models and policies for variable resources on the energy and reserve co-optimization. We also develop a general simulation platform for peer researchers to apply our designs.

Publications

[1] **S. Yin** and J. Wang, "Generation and Transmission Expansion Planning Towards a 100% Renewable Future," *IEEE Transactions on Power Systems*, pp. 1–1, 2020.

[2] **S. Yin**, J. Wang, Z. Li, and X. Fang, "State-of-the-art short-term electricity market operation with solar generation: A review," *Renewable and Sustainable Energy Reviews*, vol. 138, p. 110647, 2021.

[3] **S. Yin**, J. Wang, and H. Gangammanavar, "Stochastic market operation for coordinated transmission and distribution systems," *IEEE Transactions on Sustainable Energy*, pp. 1–1, 2021.

[4] **S. Yin**, J. Wang, X. Fang, and J. Tan, "A Generalized Multi-timescale Market Operation Framework Interfaced with Dynamic Simulation," *IEEE Transactions on Power Systems*, 2021. In Preparation.

[5] **S. Yin**, J. Wang, and F. Qiu, "Decentralized electricity market with transactive energy – A path forward," *The Electricity Journal*, vol. 32, no. 4, pp. 7–13, 2019. Special Issue on Strategies for a sustainable, reliable and resilient grid.

[6] **S. Yin**, J. Wang, and Z. Li, "Decomposable Solution Paradigm for Uncertainty-based Transmission and Distribution Coordinated Economic Dispatch," in *2019 IEEE Power Energy Society General Meeting (PESGM)*, pp. 1–5, 2019.

[7] **S. Yin**, J. Wang, Y. Lin, X. Fang, J. Tan, and H. Yuan, "Practical Operations of Energy Storage Providing Ancillary Services: From Day-Ahead to Real-Time," in *2021 North America Power Symposium (NAPS)*, pp. 1–6, 2021.

[8] Y. Lin, X. Zhang, **S. Yin**, J. Wang, and D. Shi, "Real-Time Economic Dispatch for Integrated Energy Microgrid Considering Ancillary Services," in *2020 IEEE Power Energy Society General Meeting (PESGM)*, pp. 1–5, 2020.


Thank you!
Questions?