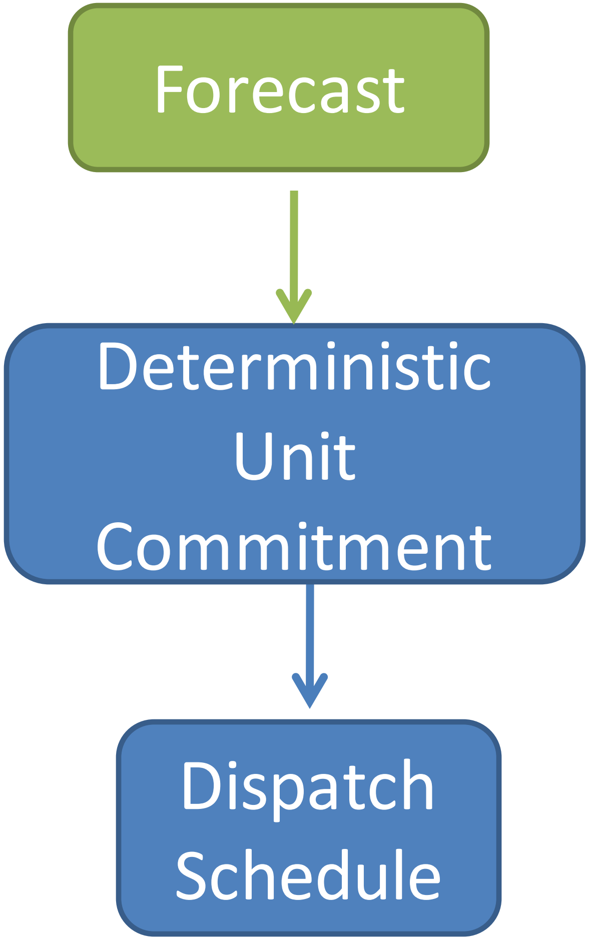
Two Stage Programs

Agenda

- What is a deterministic optimization problem? Stochastic optimization? Stochastic programming?
- Two-stage scenario-based (stochastic) programs

Deterministic Security-Constrained Unit Commitment



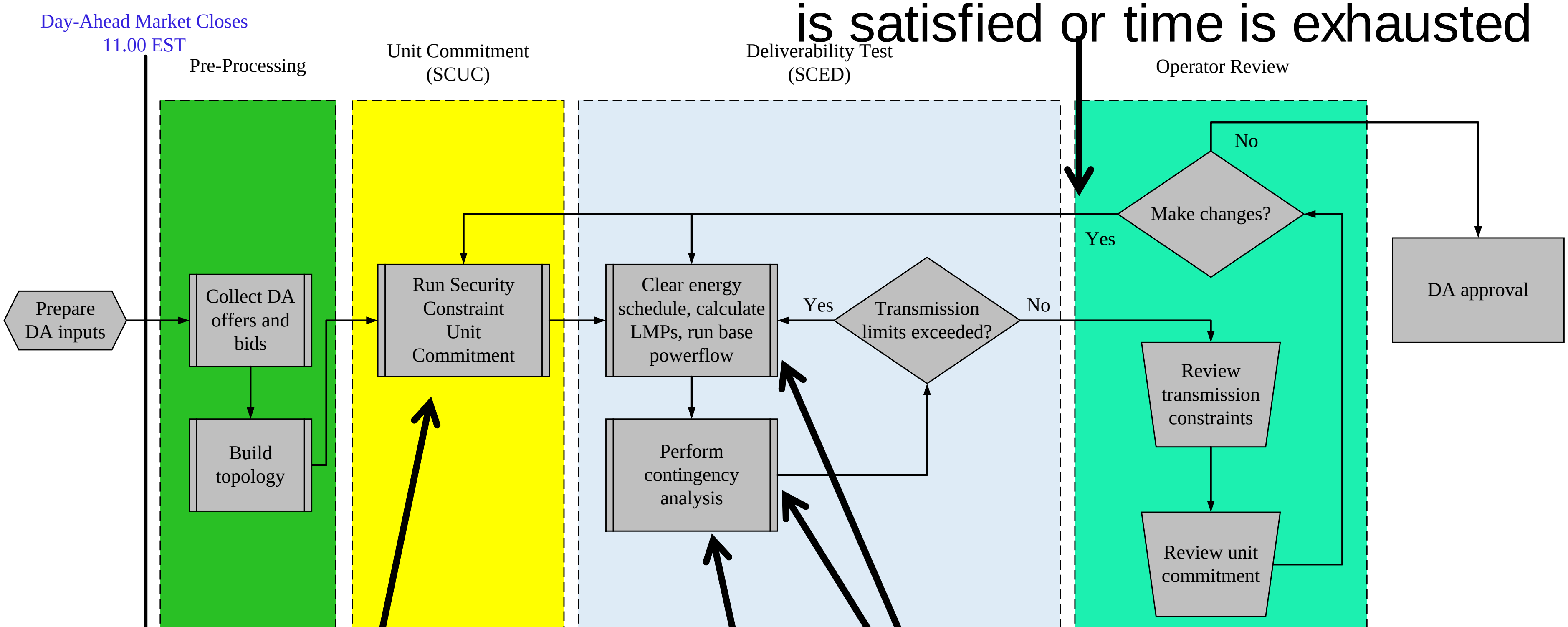
Deterministic Security-Constrained Unit Commitment/OPF

- The industry today solves **deterministic** security constrained unit commitment (SCUC) and security-constrained ED (SCED) problems
- What is a deterministic optimization problem?
- Assumes perfect forecast / no uncertainty (explicitly modeled)
- While we do not capture the true uncertainty of the problem, we model reserve requirements within SCUC and SCED, which approximate a two-stage program

Question: Is there a way to explicitly model a contingency to alleviate this problem?

Day-Ahead Scheduling in Midcontinent Independent System Operator (MISO)

Iterative process until operator is satisfied or time is exhausted



Mixed integer linear program

Reliability assessment

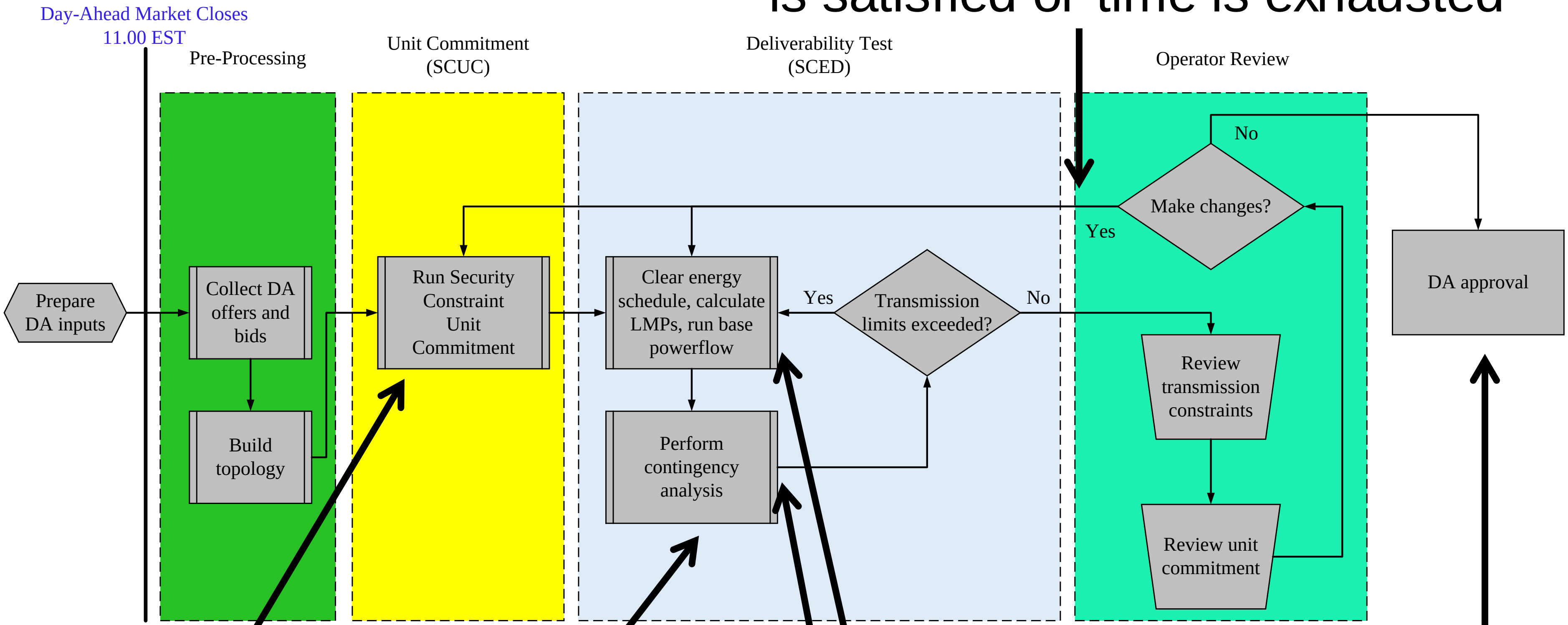
Linear program

MISO Day-Ahead Scheduling Procedure

[1] Aaron Casto, "Overview of MISO day-ahead markets," *Midwest ISO*, [Online]. Available: http://www.atcllc.com/oasis/Customer_Notices/NCM_MISO_DayAhead111507.pdf.

Day-Ahead Scheduling in Midcontinent Independent System Operator (MISO)

Iterative process until operator is satisfied or time is exhausted



Interface limits Nomograms

Subset of contingencies

DC Approximate, not AC; limited iterations

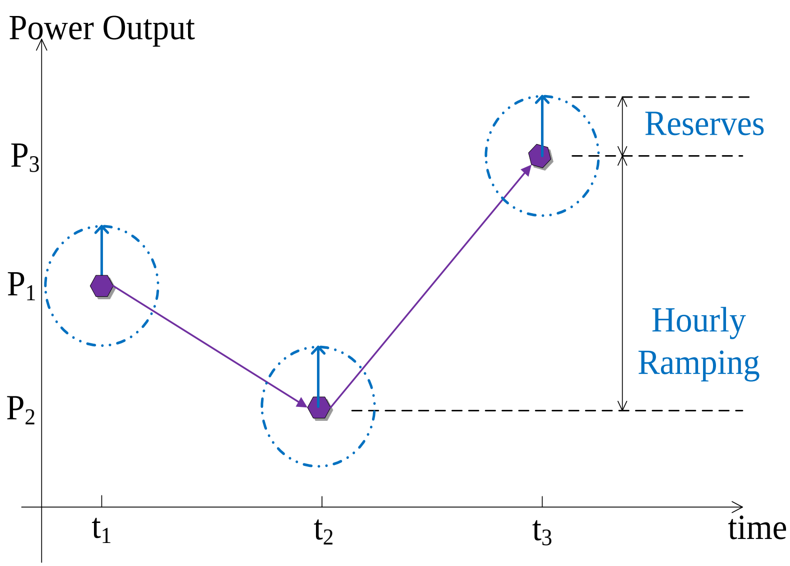
Final Day-Ahead Market Solution

Break

Two Stage Programs

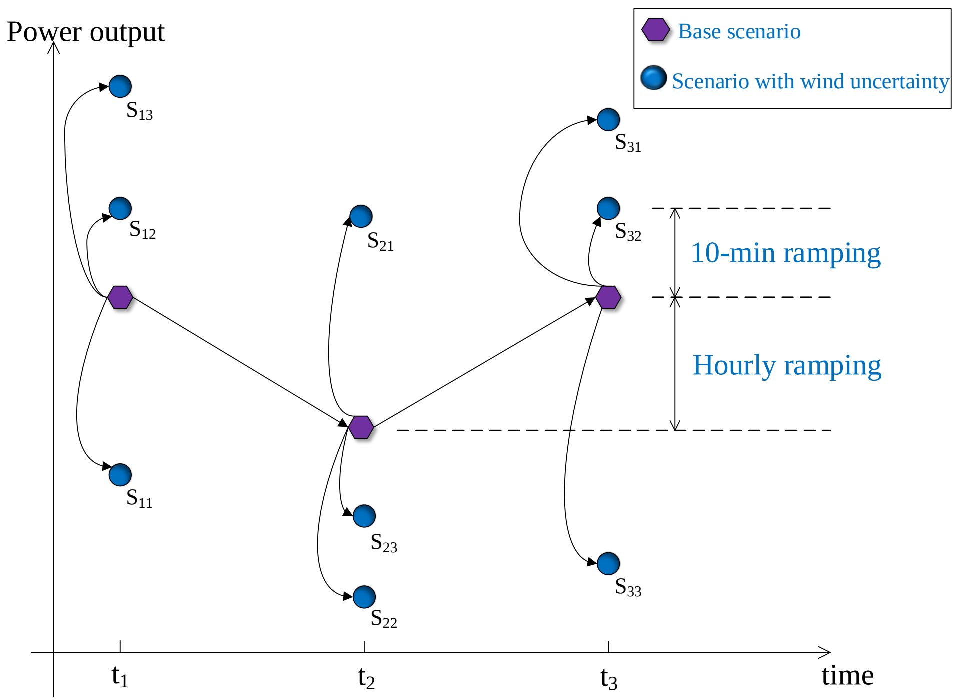
This picture shows how we generally model N-1 for stochastic unit commitment
There is a single base-case pre-contingency output
The two-stage stochastic program must ramp from the base-case to a new output for the contingency

Deterministic



Question: If you assume an infinite bus model (no OPF), how does that change the deterministic model?

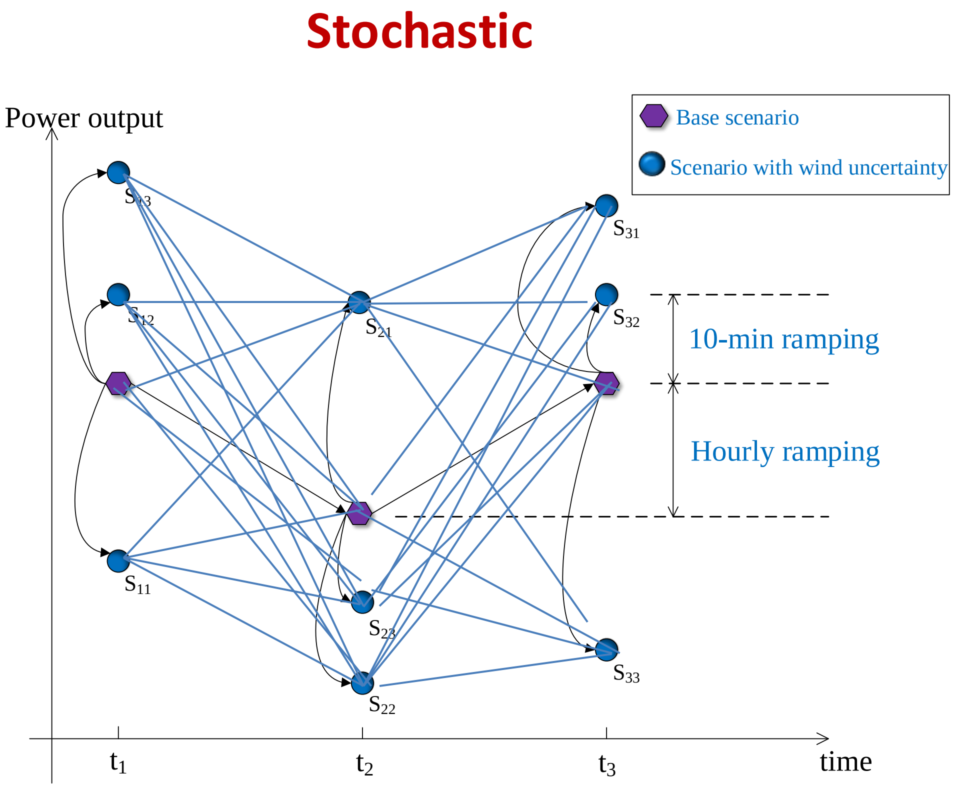
Stochastic



Two-stage stochastic program

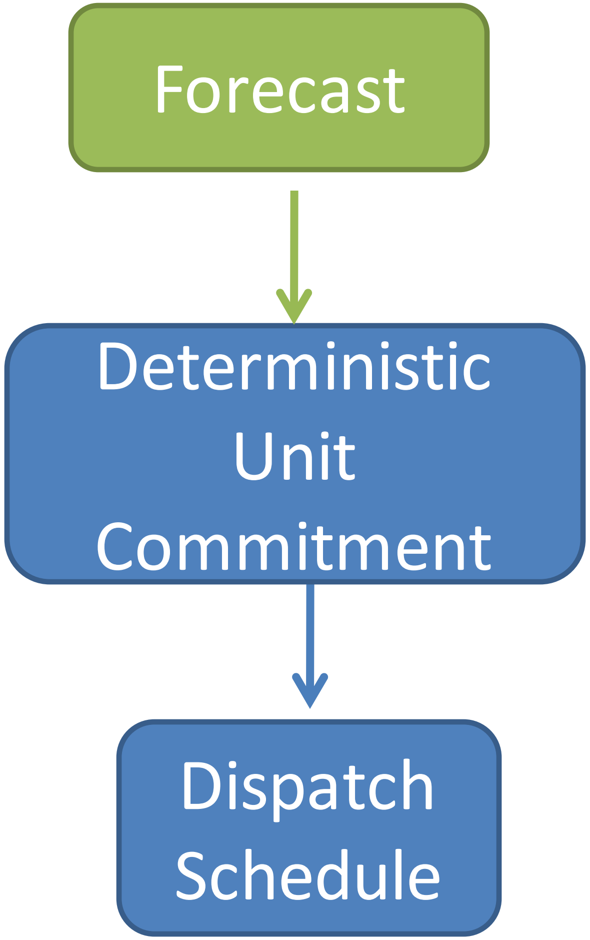
Stochastic Unit Commitment

Stochastic unit commitment (another modeling approach)



Two-stage stochastic program

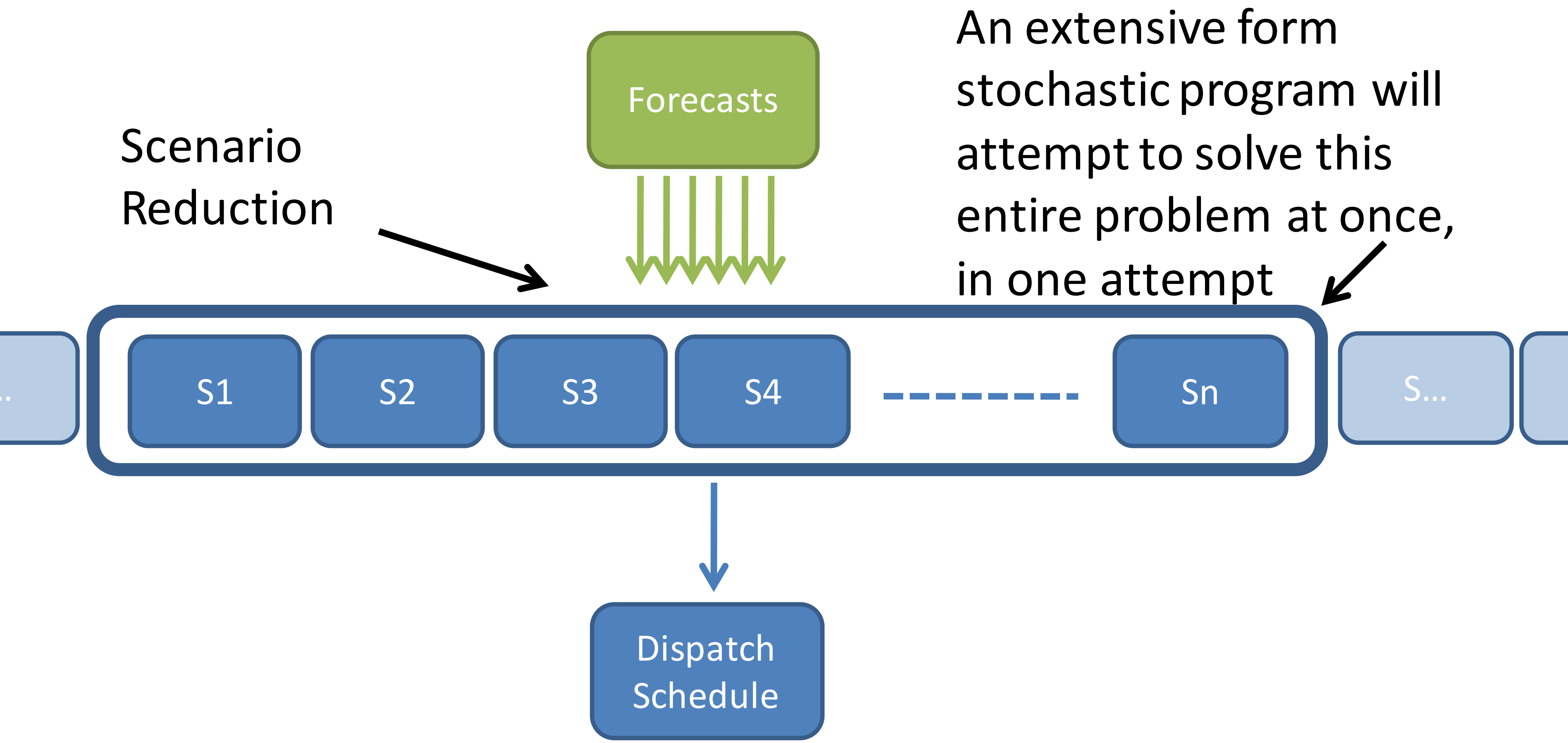
Deterministic Security-Constrained Unit Commitment



Assume the forecast is correct

Even if you procure reserves as backup capacity if your forecast is incorrect, that does not mean you are secure; you are not ensuring the reserves are deliverable since you do not model the scenarios

Extensive Form Stochastic Unit Commitment



Stochastic Unit Commitment

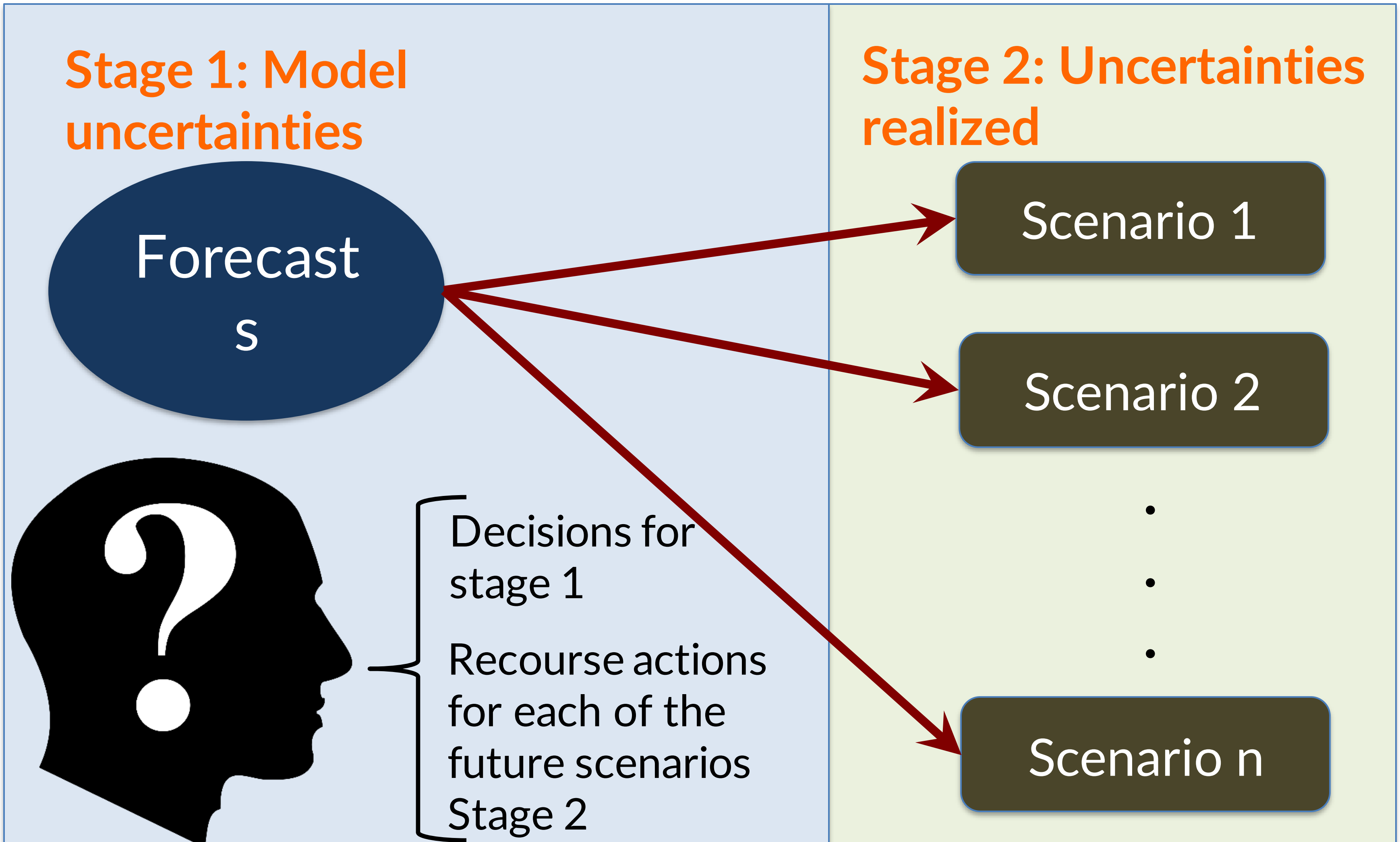
One form of stochastic unit commitment is:

- Stochastic programming
  - Captures uncertainty / multiple potential states
- Two-stage stochastic unit commitment
  - The first stage models the pre-contingency state
  - The second stage models the post-contingency state
  - The two states are linked (by constraints) that govern how the system will respond (transition from the pre-contingency to the post-contingency state) to the contingency
  - The "optimal dispatch" to this problem must not only account for the pre-contingency state but also the post-contingency state

Stochastic Unit Commitment

- Why don't we just implement stochastic programming?
- Computational complexities
  - How many contingencies does a large system have? How does the optimization problem change as a result?
- Instead, we create proxy requirements for how much reserve (and where) we need in the grid
- Note that there is a lot of research on improving the computational performance of stochastic unit commitment
  - For both N-1 reliability and the integration of renewable resources

Two-Stage Scenario-Based Stochastic Programs



Break

Two Stage Programs

Deterministic Program

- Deterministic Problem
  - Minimize total cost

$$\min C^T x$$
$$\text{st}\ Ax = b$$

- How to consider uncertainty?
  - Assumption

  : Set of realization of uncertain variables with corresponding probabilities is available

Stochastic Programming Problem

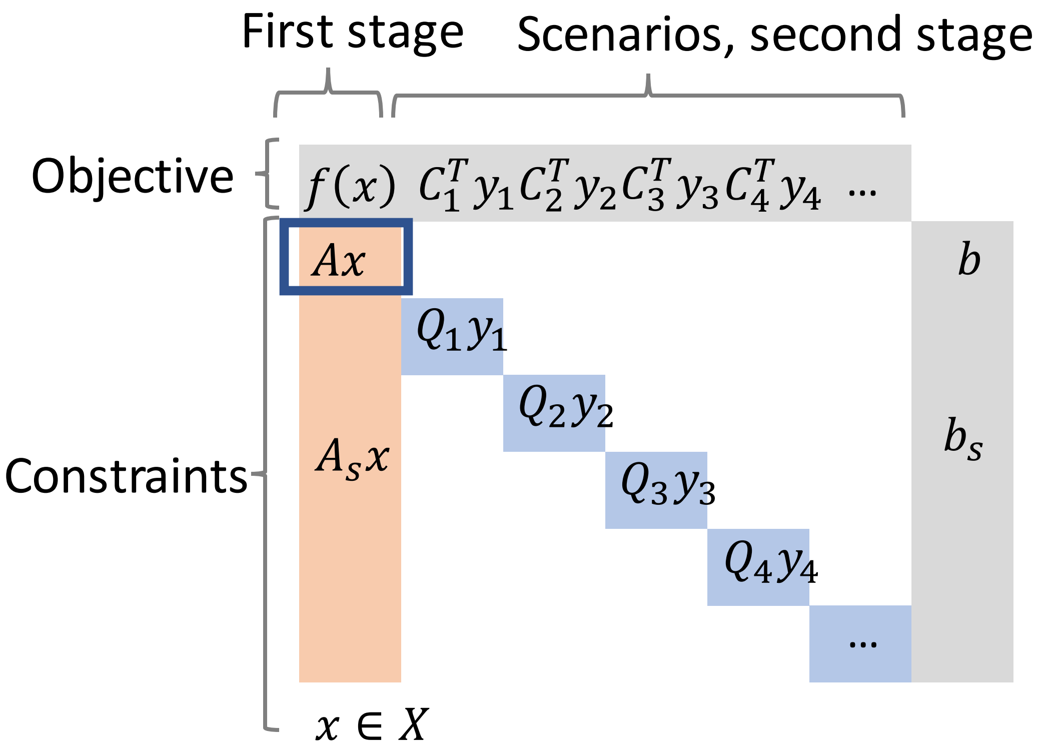
- Stochastic SCED: **Extensive Form**

$$\min \sum_{s \in S} \pi_s [C^T x + C_s y_s]$$

Subject to (s.t.):

$$Ax = b$$
$$A_s x + Q_s y_s = b_s$$

- How to solve???



First Stage Decision Variables

- First stage decision variables:
  - Decisions made prior to the uncertainty realization
  - Preventive actions
  - Base-case, pre-contingency
- First stage decisions:
  - Base-case real power generator dispatch values
  - Ancillary services procured
  - (Resulting base-case pre-contingency line flows)

Second-Stage Decision Variables

- Second stage decision variables:
  - Corrective control capability implemented only after the event/scenario/contingency occurs
- Second stage decisions:
  - Activation of reserve – how much (gen redispatch)
  - (Resulting base-case pre-contingency line flows)

Agreement Across Scenarios

- First stage decisions must agree across scenarios

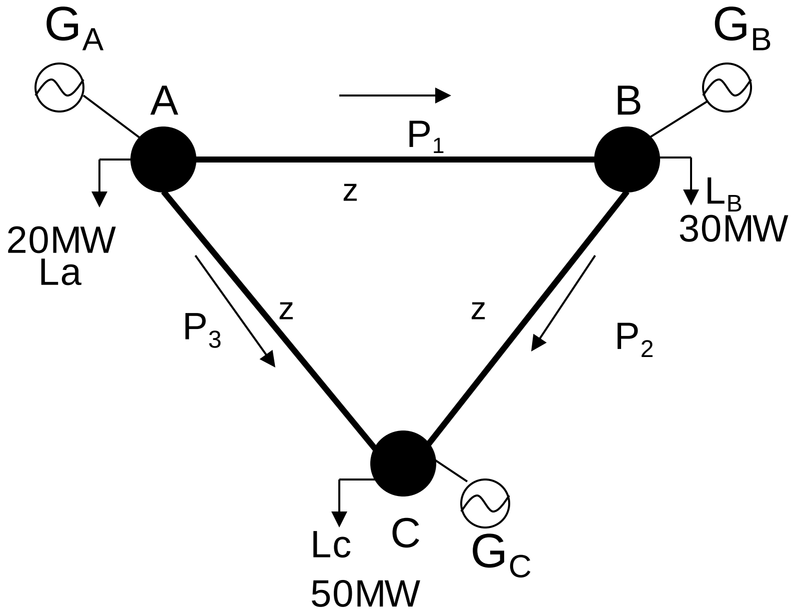
- Second stage decisions are free to vary but are linked together through the first stage decisions

Break

Two Stage Programs

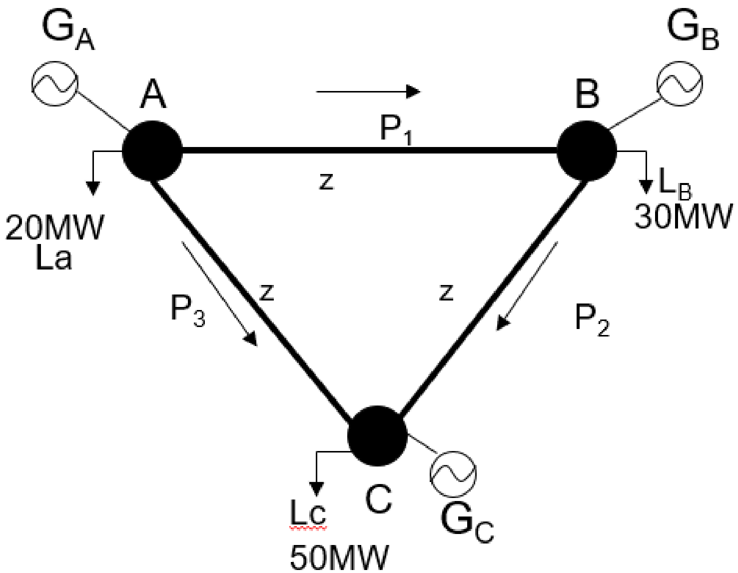
Example: SCED

SCED



The presented formulation is a SCED as it incorporates security criteria in the form of explicit representation of transmission contingencies as well as generator contingency modeling.

Example: SCED
Base-Case
Pre-contingency
First-Stage Modeling



Gen Modeling (example):

$0 \le G_A, 0 \le G_B, 0 \le G_C$

$G_A + r_A \le 80$

$G_B + r_B \le 70$

$G_C + r_C \le 60$

$0 \le r_A \le 40; 0 \le r_B \le 30; 0 \le r_C \le 20$

$r_A + r_B + r_C \ge G_A + r_A$

$r_A + r_B + r_C \ge G_B + r_B$

$r_A + r_B + r_C \ge G_C + r_C$

Gen Modeling (generic):

$P_g^{min} \le p_{gt} \quad \forall g \in G, t \in T$

$p_{gt} + r_{gt}^{spin} \le P_g^{max} \quad \forall g, t$

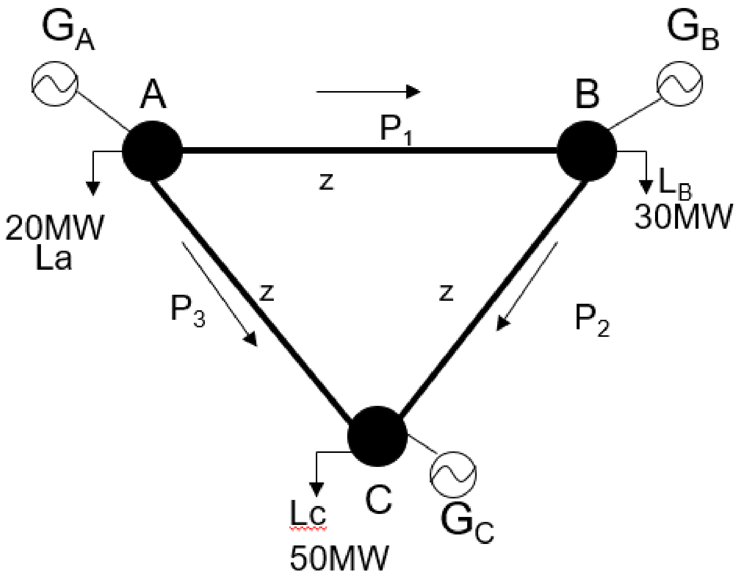
$0 \le r_{gt}^{spin} \le R_g^{10\ spin} \quad \forall g, t$

$\sum_{\forall s \in G} r_{st}^{spin} \ge p_{gt} + r_{gt}^{spin} \quad \forall g, t$ (x)

p_{gt}: First stage pre-contingency dispatch setpoint, gen g, period t

r_{gt}^{spin}: First stage pre-contingency 10-minute spin reserve from gen g; note that s references the generator set just as g does; note that you could write (x) as (xx) instead

$\sum_{\substack{\forall s \in G \\ s != g}} r_{st}^{spin} \ge p_{gt} \quad \forall g, t$ (xx)



Base Case Power Flow Modeling (example):

$$-40 \leq \frac{1}{3}(G_A - 20) - \frac{1}{3}(G_B - 30) \leq 40$$
$$-40 \leq \frac{1}{3}(G_A - 20) + \frac{2}{3}(G_B - 30) \leq 40$$
$$-40 \leq \frac{2}{3}(G_A - 20) + \frac{1}{3}(G_B - 30) \leq 40$$
$$G_A + G_B + G_C = 100$$

Bus c is the reference bus

Base Case Power Flow Modeling (generic):

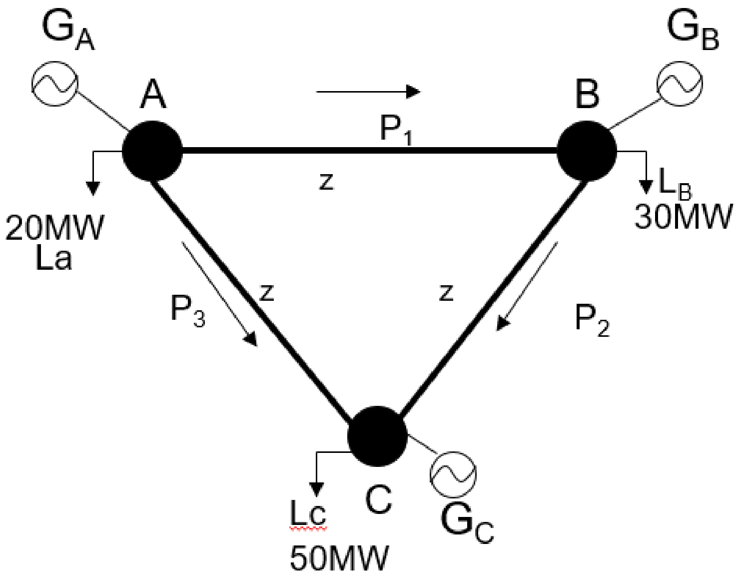
$$P_k^{min} \leq \sum_{\forall n} PTDF_{k,n}^R \left(\sum_{\forall g \in G^n}(p_{gt}) - D_{nt}\right) \leq P_k^{max} \quad \forall k, t$$
$$p_{k,t}^0 = \sum_{\forall n} PTDF_{k,n}^R \left(\sum_{\forall g \in G^n}(p_{gt}) - D_{nt}\right) \forall k, t$$
$$\sum_{\forall g}(p_{gt}) = \sum_{\forall n}(D_{nt}) \qquad \forall t$$

p_{gt}: First stage pre-contingency dispatch setpoint, gen g, period t
p_{kt}^0: First stage pre-contingency power flow on branch k, gen g, period t; this var is not needed truly but I am defining it to make a follow-on equation easier to write.

Break

Two Stage Programs

Example: SCED Post-contingency Transmission Contingency Second-Stage Modeling



Post Contingency (Trans) Power Flow Modeling (generic):

$$P_k^{min,rate\ c} \leq p_{kt}^0 + LODF_{k,\ell} p_{\ell t}^0 \leq P_k^{min,rate\ c} \quad \forall k \in K, k! = \ell, \ell \in K, t \in T$$

$$p_{k\ell t} = p_{kt}^0 + LODF_{k,\ell} p_{\ell t}^0 \quad \forall k \in K, k! = \ell, \ell \in K, t \in T$$

p_{kt}^0: First stage pre-contingency power flow on branch k, period t

$p_{k\ell t}$: Second stage post-contingency power flow on branch k, period t, for the loss of line ℓ

$$P_k^{min,rate\ c} \leq \sum_{\forall n} PTDF_{k,n}^{R\ loss\ of\ \ell} \left(\sum_{\forall g \in G^n} (p_{g\ell t}) - D_{nt} \right) \leq P_k^{max,rate\ c} \quad \forall k, \ell, t$$

$p_{g\ell t}^{loss\ of \ell} = p_{gt}$: non-anticipativity constraint

Another way to formulate (above)

Note that there are limitations when LODFs can be used; refer to Power Generation, Operation, and Control textbook

Very important: most security criteria modeling for transmission contingencies assume no movement away from the pre-contingency dispatch setpoints. Power system engineers often impose that the pre-contingency setpoints satisfy post-contingency limits for a single transmission contingency. If you go back to the prior slide, p_{kt}^{0} (and $p_{\ell t}^{0}$ as well) are defined based only on first-stage pre-contingency dispatch setpoint injections. There is no need to declare a variable $p_{k\ell t}$, which can be seen to have a new index. Many people see the first equation and since it is based on the pre-contingency flows only (determined then by the pre-contingency dispatch setpoints again), they don't declare this to be a two-stage program. But it is. Look to the right. The sets defining how this equation is declared specify that you have K*K equations being included – you are directly representing an unknown event, a loss of a line, and then determining the impact on all lines.

Post Contingency (Trans) Power Flow Modeling (generic):

$$P_k^{min,rate\ c} \leq p_{kt}^0 + LODF_{k,\ell} p_{\ell t}^0 \leq P_k^{min,rate\ c} \quad \forall k \in K, k! = \ell, \ell \in K, t \in T$$

$$p_{k\ell t} = p_{kt}^0 + LODF_{k,\ell} p_{\ell t}^0 \quad \forall k \in K, k! = \ell, \ell \in K, t \in T$$

p_{kt}^0: First stage pre-contingency power flow on branch k, period t

$p_{k\ell t}$: Second stage post-contingency power flow on branch k, period t, for the loss of line ℓ

$$P_k^{min,rate\ c} \leq \sum_{\forall n} PTDF_{k,n}^{R\ loss\ of\ \ell} \left(\sum_{\forall g \in G^n} (p_{g\ell t}) - D_{nt}\right) \leq P_k^{max,rate\ c} \quad \forall k, \ell, t$$

$p_{g\ell t}^{loss\ of \ell} = p_{gt}$: non-anticipativity constraint

Another way to formulate (above)

Note that there are limitations when LODFs can be used; refer to the 577 textbook (available online via ASU Library

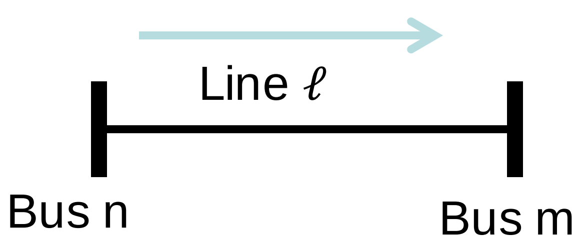
Line Outage Distribution Factors

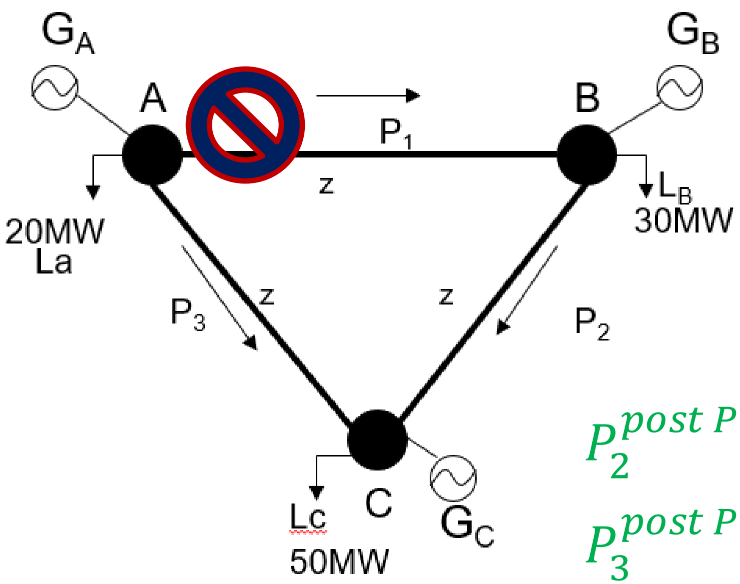
- An LODF allows you to determine the resulting flow on a particular line due to the loss of a different line
- When monitoring line *k*, what is the new flow on line *k* after you lose line ℓ

0 represents state 0, the base case, the pre-contingency state

$$P_k^{new} = P_k^0 + LODF_{k,\ell} {P^0}_{\ell}$$

$$LODF_{k,\ell} = PTDF_{n,k}^m \left(\frac{1}{1 - PTDF_{n,\ell}^m} \right)$$





Post Cont (Trans) Power Flow Modeling: (example loss of line 1):

$$P_1^{pre} = \frac{1}{3}(G_A - 20) - \frac{1}{3}(G_B - 30)$$
$$P_2^{pre} = \frac{1}{3}(G_A - 20) + \frac{2}{3}(G_B - 30)$$
$$P_3^{pre} = \frac{2}{3}(G_A - 20) + \frac{1}{3}(G_B - 30)$$

$$P_2^{post\,P1} = P_2^{pre} + (-\tfrac{1}{3})\left(\frac{1}{1-2/3}\right)P_1^{pre}$$
$$P_3^{post\,P1} = P_3^{pre} + (\tfrac{1}{3})\left(\frac{1}{1-2/3}\right)P_1^{pre}$$

$-60 \le P_2^{post\,P1}$

$P_2^{post\,P1} \le 60$

$-60 \le P_3^{post\,P1}$

$P_3^{post\,P1} \le 60$

LODFs are in purple

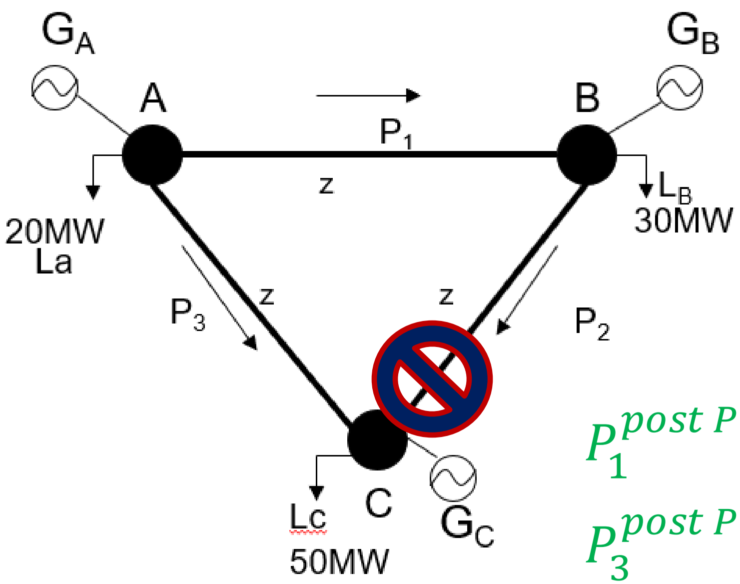
Post Contingency (Trans) Power Flow Modeling (generic):

$$P_k^{min,rate\,c} \le p_{kt}^0 + LODF_{k,\ell}\,p_{\ell t}^0 \le P_k^{min,rate\,c} \quad \forall k \in K, k! = \ell, \ell \in K, t \in T$$
$$p_{k\ell t} = p_{kt}^0 + LODF_{k,\ell}\,p_{\ell t}^0 \quad \forall k \in K, k! = \ell, \ell \in K, t \in T$$

p_{kt}^0: First stage pre-contingency power flow on branch k, period t

$p_{k\ell t}$: Second stage post-contingency power flow on branch k, period t, for the loss of line ℓ

$$P_2^{post\,P1} = \frac{1}{3}(G_A - 20) + \frac{2}{3}(G_B - 30) + (-1)\left(\frac{1}{3}(G_A - 20) - \frac{1}{3}(G_B - 30)\right) = (G_B - 30)$$
$$P_3^{post\,P1} = \frac{2}{3}(G_A - 20) + \frac{1}{3}(G_B - 30) + (1)\left(\frac{1}{3}(G_A - 20) - \frac{1}{3}(G_B - 30)\right) = (G_A - 20)$$



Post Cont (Trans) Power Flow Modeling: (example loss of line 2):

$$P_1^{pre} = \frac{1}{3}(G_A - 20) - \frac{1}{3}(G_B - 30)$$
$$P_2^{pre} = \frac{1}{3}(G_A - 20) + \frac{2}{3}(G_B - 30)$$
$$P_3^{pre} = \frac{2}{3}(G_A - 20) + \frac{1}{3}(G_B - 30)$$

$$P_1^{post\ P2} = P_1^{pre} + (-\frac{1}{3})\left(\frac{1}{1-2/3}\right)P_2^{pre}$$
$$P_3^{post\ P2} = P_3^{pre} + (\frac{1}{3})\left(\frac{1}{1-2/3}\right)P_2^{pre}$$

$$-60 \le P_1^{post\ P2}$$
$$P_1^{post\ P2} \le 60$$
$$-60 \le P_3^{post\ P2}$$
$$P_3^{post\ P2} \le 60$$

LODFs are in purple

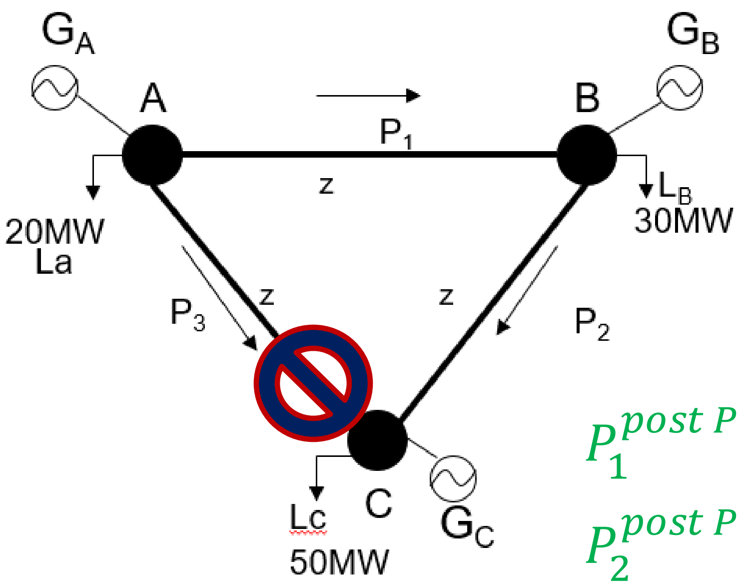
Post Contingency (Trans) Power Flow Modeling (generic):

$$P_k^{min,rate\ c} \le p_{kt}^0 + LODF_{k,\ell} p_{\ell t}^0 \le P_k^{min,rate\ c} \quad \forall k \in K, k! = \ell, \ell \in K, t \in T$$
$$p_{k\ell t} = p_{kt}^0 + LODF_{k,\ell} p_{\ell t}^0 \quad \forall k \in K, k! = \ell, \ell \in K, t \in T$$

p_{kt}^0: First stage pre-contingency power flow on branch k, period t

$p_{k\ell t}$: Second stage post-contingency power flow on branch k, period t, for the loss of line ℓ

$$P_1^{post\ P2} = \frac{1}{3}(G_A - 20) - \frac{1}{3}(G_B - 30) + (-1)\left(\frac{1}{3}(G_A - 20) + \frac{2}{3}(G_B - 30)\right) = -(G_B - 30)$$
$$P_3^{post\ P2} = \frac{2}{3}(G_A - 20) + \frac{1}{3}(G_B - 30) + (1)\left(\frac{1}{3}(G_A - 20) + \frac{2}{3}(G_B - 30)\right)$$
$$= (G_A - 20) + (G_B - 30)$$



Post Cont (Trans) Power Flow Modeling: (example loss of line 3):

$$P_1^{pre} = \frac{1}{3}(G_A - 20) - \frac{1}{3}(G_B - 30)$$
$$P_2^{pre} = \frac{1}{3}(G_A - 20) + \frac{2}{3}(G_B - 30)$$
$$P_3^{pre} = \frac{2}{3}(G_A - 20) + \frac{1}{3}(G_B - 30)$$

$$P_1^{post\ P3} = P_1^{pre} + \left(\frac{1}{3}\right)\left(\frac{1}{1-2/3}\right) P_3^{pre}$$
$$P_2^{post\ P3} = P_2^{pre} + \left(\frac{1}{3}\right)\left(\frac{1}{1-2/3}\right) P_3^{pre}$$

$$-60 \le P_1^{post\ P3}$$
$$P_1^{post\ P3} \le 60$$
$$-60 \le P_2^{post\ P3}$$
$$P_2^{post\ P3} \le 60$$

LODFs are in purple

Post Contingency (Trans) Power Flow Modeling (generic):

$$P_k^{min,rate\ c} \le p_{kt}^0 + LODF_{k,\ell} p_{\ell t}^0 \le P_k^{min,rate\ c} \quad \forall k \in K, k! = \ell, \ell \in K, t \in T$$
$$p_{k\ell t} = p_{kt}^0 + LODF_{k,\ell} p_{\ell t}^0 \quad \forall k \in K, k! = \ell, \ell \in K, t \in T$$

p_{kt}^0: First stage pre-contingency power flow on branch k, period t

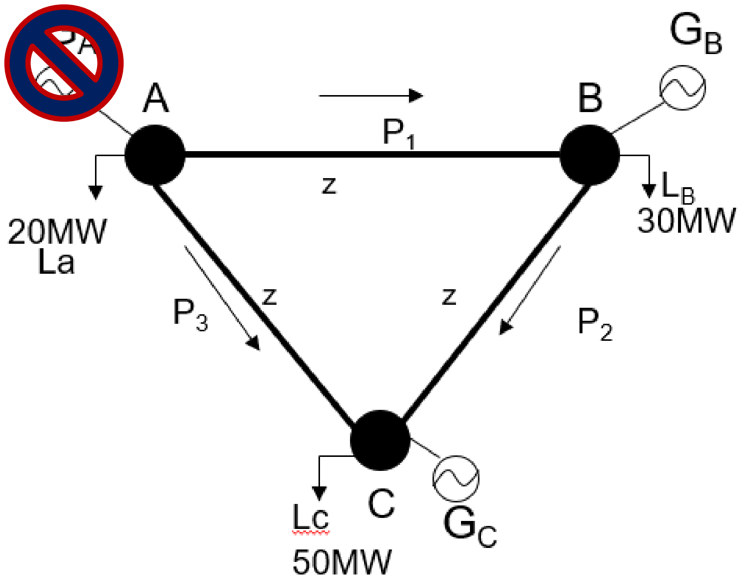
$p_{k\ell t}$: Second stage post-contingency power flow on branch k, period t, for the loss of line ℓ

$$P_1^{post\ P3} = \frac{1}{3}(G_A - 20) - \frac{1}{3}(G_B - 30) + (1)\left(\frac{2}{3}(G_A - 20) + \frac{1}{3}(G_B - 30)\right) = (G_A - 20)$$
$$P_2^{post\ P3} = \frac{1}{3}(G_A - 20) + \frac{2}{3}(G_B - 30) + (1)\left(\frac{2}{3}(G_A - 20) + \frac{1}{3}(G_B - 30)\right)$$
$$= (G_A - 20) + (G_B - 30)$$

Break

Two Stage Programs

Example: SCED Post-contingency Generator Contingency Second-Stage Modeling



Post Cont (gen) Modeling (example loss of gen A):

$$r_B^{loss\ A} + r_C^{loss\ A} = G_A$$
$$-30 \le r_B^{loss\ A} \le r_B; -20 \le r_C^{loss\ A} \le r_C$$
$$0 \le r_B^{loss\ A} + G_B; 0 \le r_C^{loss\ A} + G_C$$
$$-60 \le \frac{1}{3}(-20) - \frac{1}{3}\left(G_B + r_B^{loss\ A} - 30\right) \le 60$$
$$-60 \le \frac{1}{3}(-20) + \frac{2}{3}\left(G_B + r_B^{loss\ A} - 30\right) \le 60$$
$$-60 \le \frac{2}{3}(-20) + \frac{1}{3}\left(G_B + r_B^{loss\ A} - 30\right) \le 60$$

Post Contingency (Gen) Power Flow Modeling (generic):

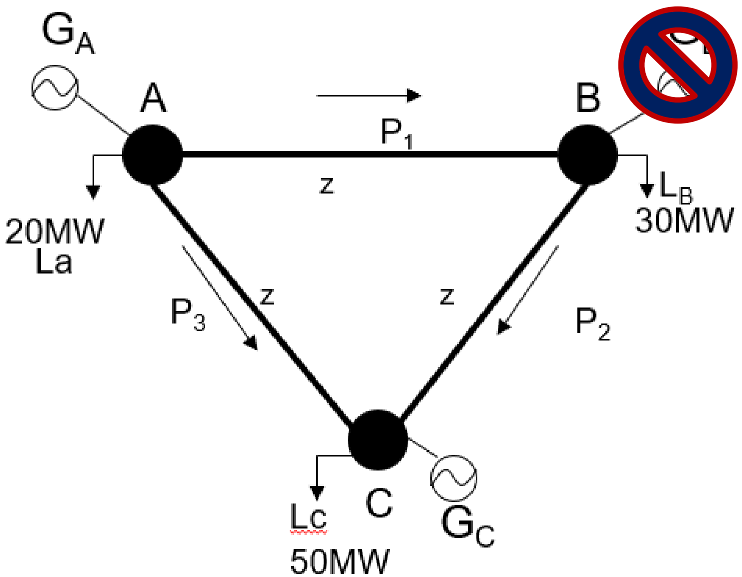
$$P_k^{min,rate\ c} \le p_{kht} \le P_k^{min,rate\ c} \quad \forall k \in K, h \in G, t \in T$$
$$p_{kht} = \sum_{\forall n}\left[PTDF_{k,n}^{R}\left(\sum_{\forall g \in G^n}\left(p_{gt} + r_{ght}^{spin}\right) - D_{nt}\right)\right] - PTDF_{k,h@n}^{R} p_{g=h,t}$$
$$\sum_{\forall g} r_{ght}^{spin} = p_{g=h,t} \quad \forall g \in G, h \in G, t \in T \qquad P_g^{min} \le p_{gt} + r_{ght}^{spin} \ \forall g \in G, h \in G, t \in T$$
$$r_{g=h,h,t}^{spin} = 0 \quad \forall h \in G, t \in T \qquad -R_g^{10\ spin} \le r_{ght}^{spin} \le r_{gt}^{spin} \ \forall g \in G, h \in G, t \in T$$

p_{gt}: First stage pre-contingency gen dispatch setpoint for gen g, period t

r_{gt}^{spin}: First stage pre-contingency gen 10-min spin reserve for gen g, period t

r_{ght}^{spin}: Second stage post-contingency spin reserve *activated* from gen g in response to loss of gen h, in period t

p_{kht}: Second stage post-contingency power flow on line k, outage of gen h, period t



Post Cont (gen) Modeling (example loss of gen B):

$$r_A^{loss\ B} + r_C^{loss\ B} = G_B$$

$$-40 \le r_A^{loss\ B} \le r_A; -20 \le r_C^{loss\ B} \le r_C$$

$$0 \le r_A^{loss\ B} + G_A; 0 \le r_C^{loss\ B} + G_C$$

$$-60 \le \frac{1}{3}\left(G_A + r_A^{loss\ B} - 20\right) - \frac{1}{3}(-30) \le 60$$

$$-60 \le \frac{1}{3}\left(G_A + r_A^{loss\ B} - 20\right) + \frac{2}{3}(-30) \le 60$$

$$-60 \le \frac{2}{3}\left(G_A + r_A^{loss\ B} - 20\right) + \frac{1}{3}(-30) \le 60$$

Post Contingency (Gen) Power Flow Modeling (generic):

$$P_k^{min,rate\ c} \le p_{kht} \le P_k^{min,rate\ c} \quad \forall k \in K, h \in G, t \in T$$

$$p_{kht} = \sum_{\forall n}\left[PTDF_{k,n}^R\left(\sum_{\forall g \in G^n}\left(p_{gt} + r_{ght}^{spin}\right) - D_{nt}\right)\right] - PTDF_{k,h@n}^R p_{g=h,t}$$

$$\sum_{\forall g} r_{ght}^{spin} = p_{g=h,t} \quad \forall g \in G, h \in G, t \in T \qquad P_g^{min} \le p_{gt} + r_{ght}^{spin} \ \forall g \in G, h \in G, t \in T$$

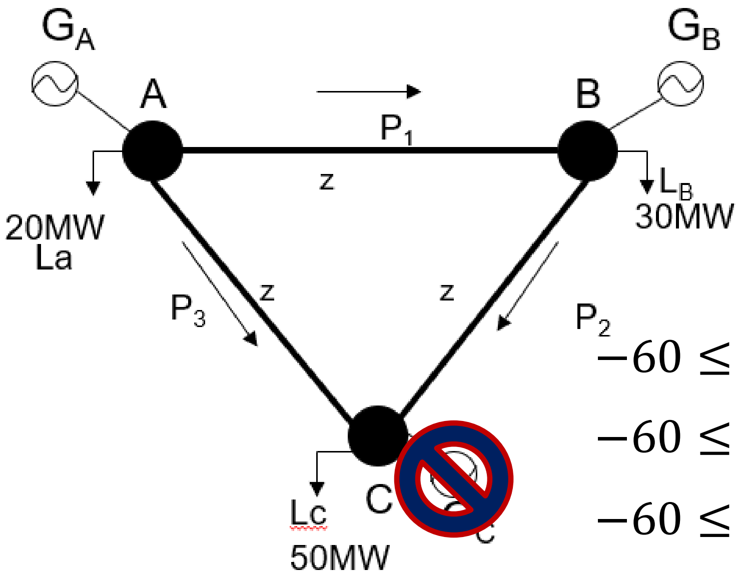
$$r_{g=h,h,t}^{spin} = 0 \quad \forall h \in G, t \in T \qquad -R_g^{10\ spin} \le r_{ght}^{spin} \le r_{gt}^{spin} \ \forall g \in G, h \in G, t \in T$$

p_{gt}: First stage pre-contingency gen dispatch setpoint for gen g, period t

r_{gt}^{spin}: First stage pre-contingency gen 10-min spin reserve for gen g, period t

r_{ght}^{spin}: Second stage post-contingency spin reserve *activated* from gen g in response to loss of gen h, in period t

p_{kht}: Second stage post-contingency power flow on line k, outage of gen h, period t



Post Cont (gen) Modeling (example loss of gen C):

$$r_A^{loss\ C} + r_B^{loss\ C} = G_C$$

$$-40 \le r_A^{loss\ C} \le r_A; -30 \le r_B^{loss\ C} \le r_B$$

$$0 \le r_A^{loss\ C} + G_A; 0 \le r_B^{loss\ C} + G_B$$

$$-60 \le \frac{1}{3}\left(G_A + r_A^{loss\ C} - 20\right) - \frac{1}{3}\left(G_B + r_B^{loss\ C} - 30\right) \le 60$$

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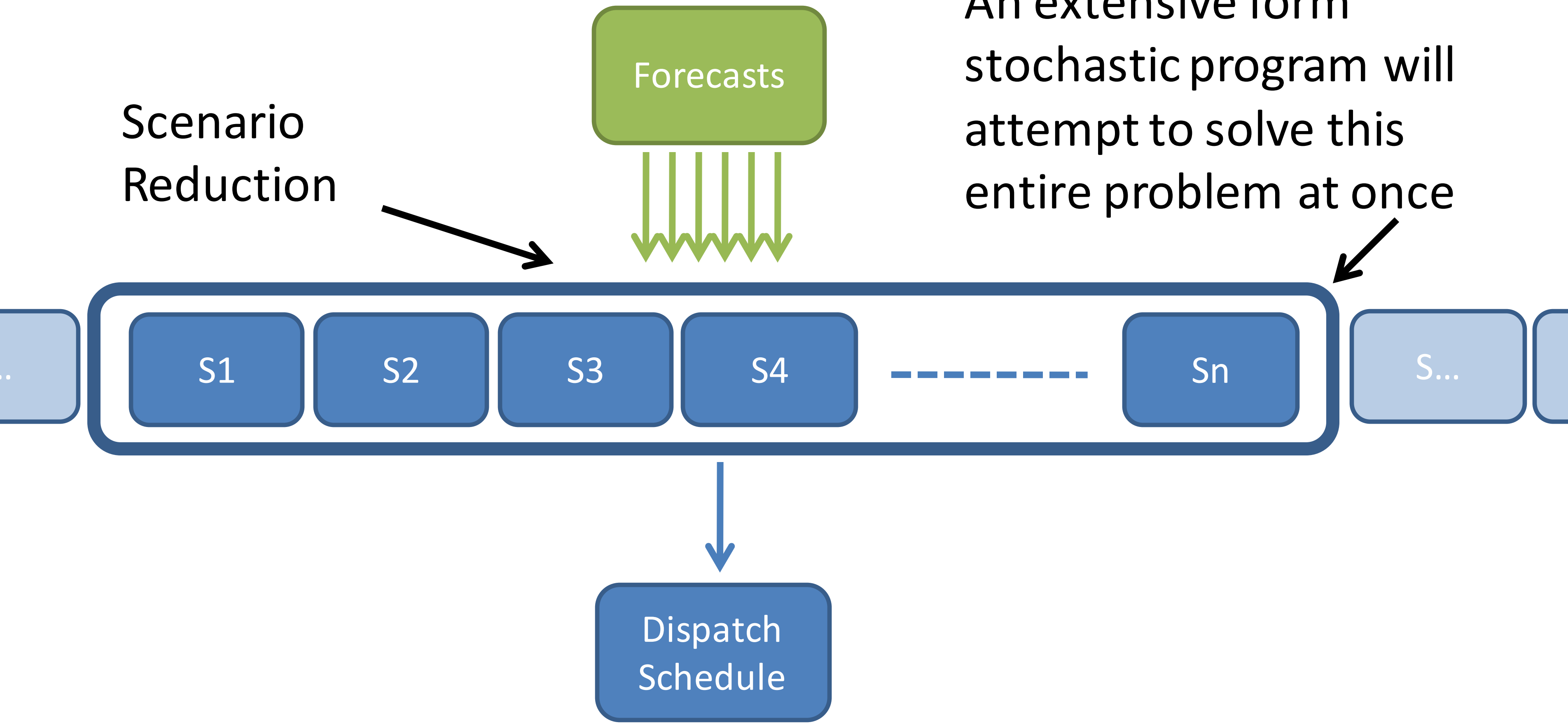
Break

Two Stage Programs

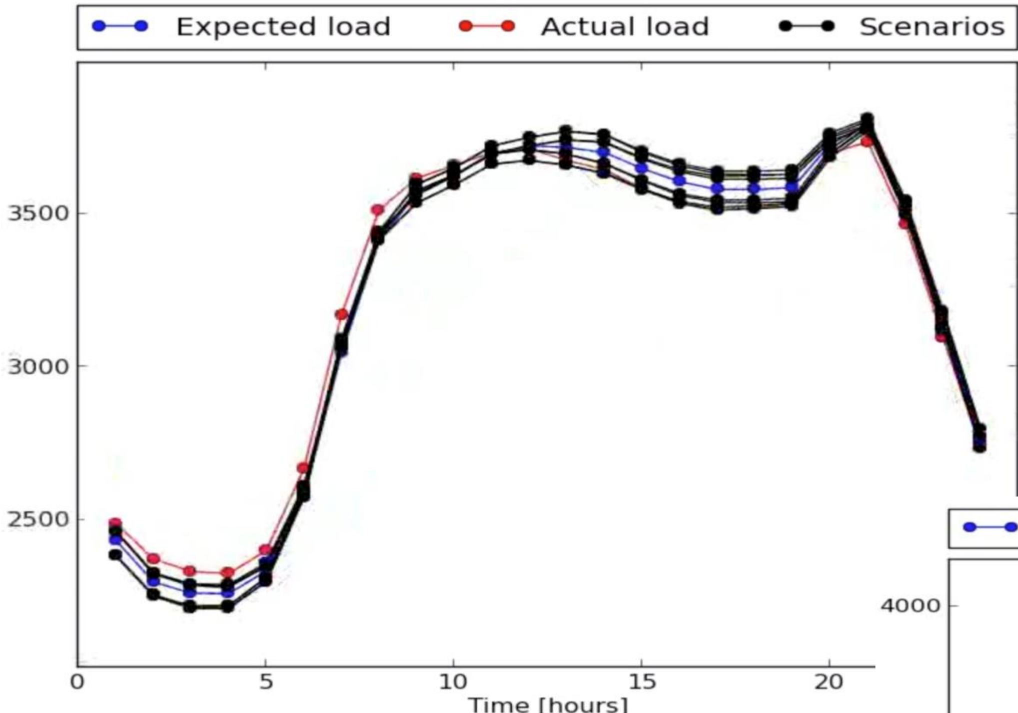
Extensive Form Stochastic Unit Commitment

An extensive form stochastic program will attempt to solve this entire problem at once

Scenario Reduction

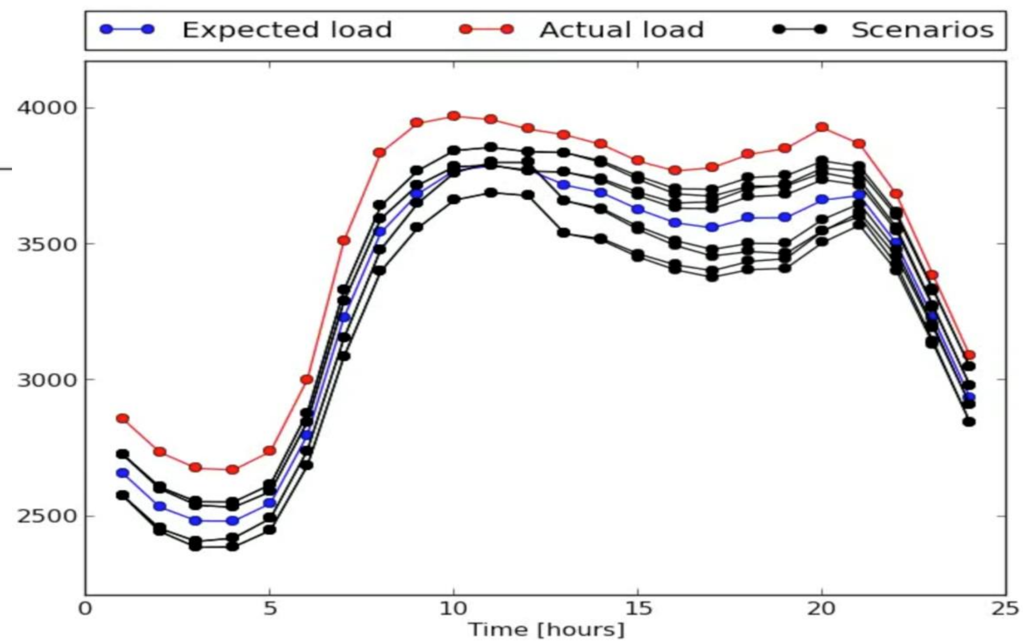


Illustrative Load Scenarios: ISO-NE



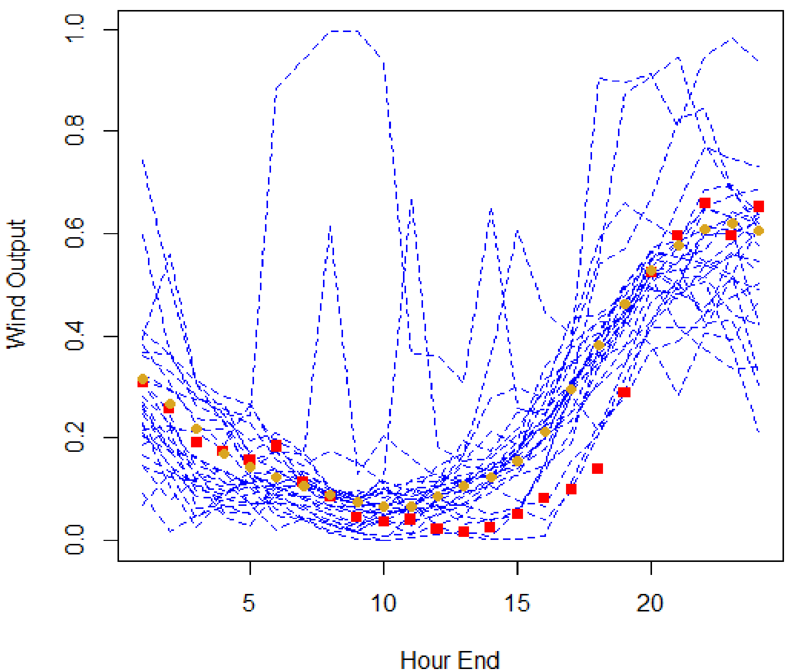
If the historical data indicates no variability, then the scenarios will reflect that consistency

Captures variability in load when present – but predictions are not perfect!

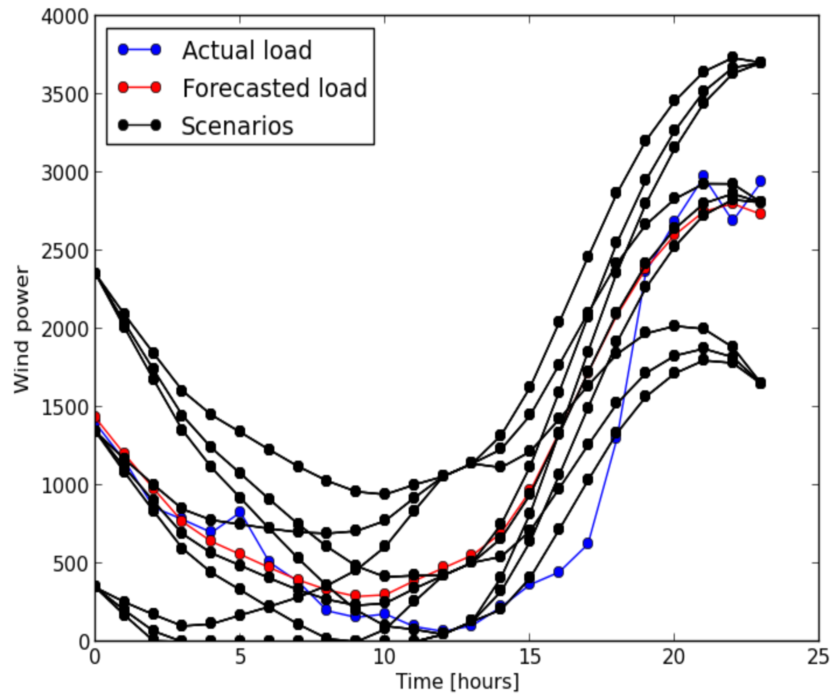


Wind Scenario Generation Examples

Scenarios generated using Pinson et al. method



Scenarios generated using epi-spline approach

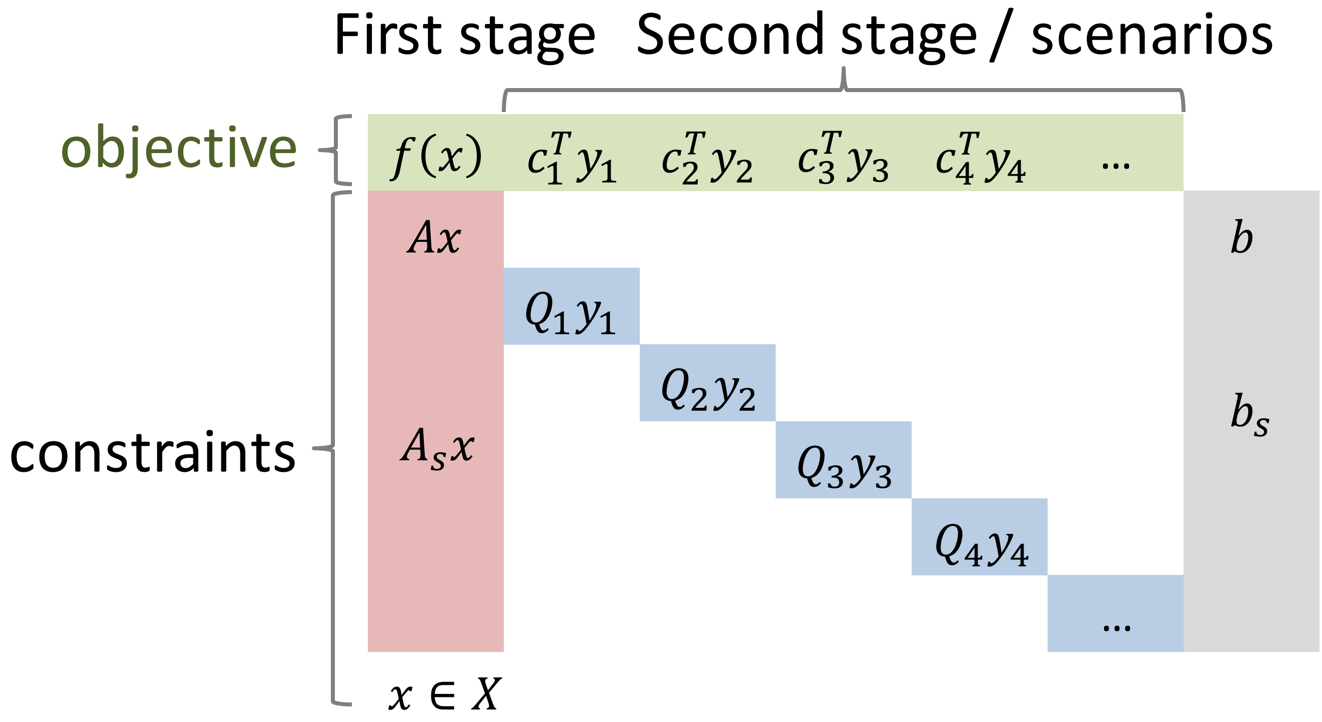


Note: Real wind profiles show significant ramps, but not as extreme as those obtained using (e.g.,) the Pinson et al. method

Block Diagonal Structure

Two stage-stochastic programs

- **Stage one** (x): base-case decisions made here and now
- **Stage two** (y): recourse decisions that can be deferred



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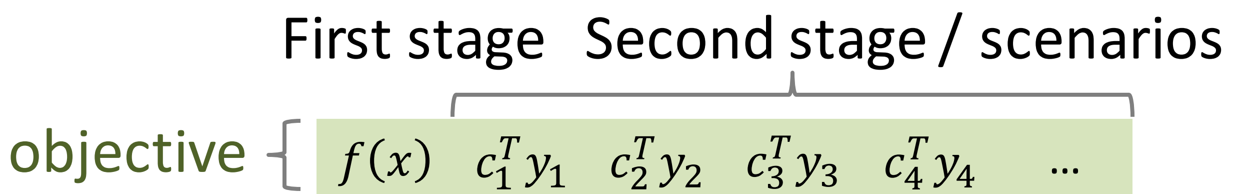


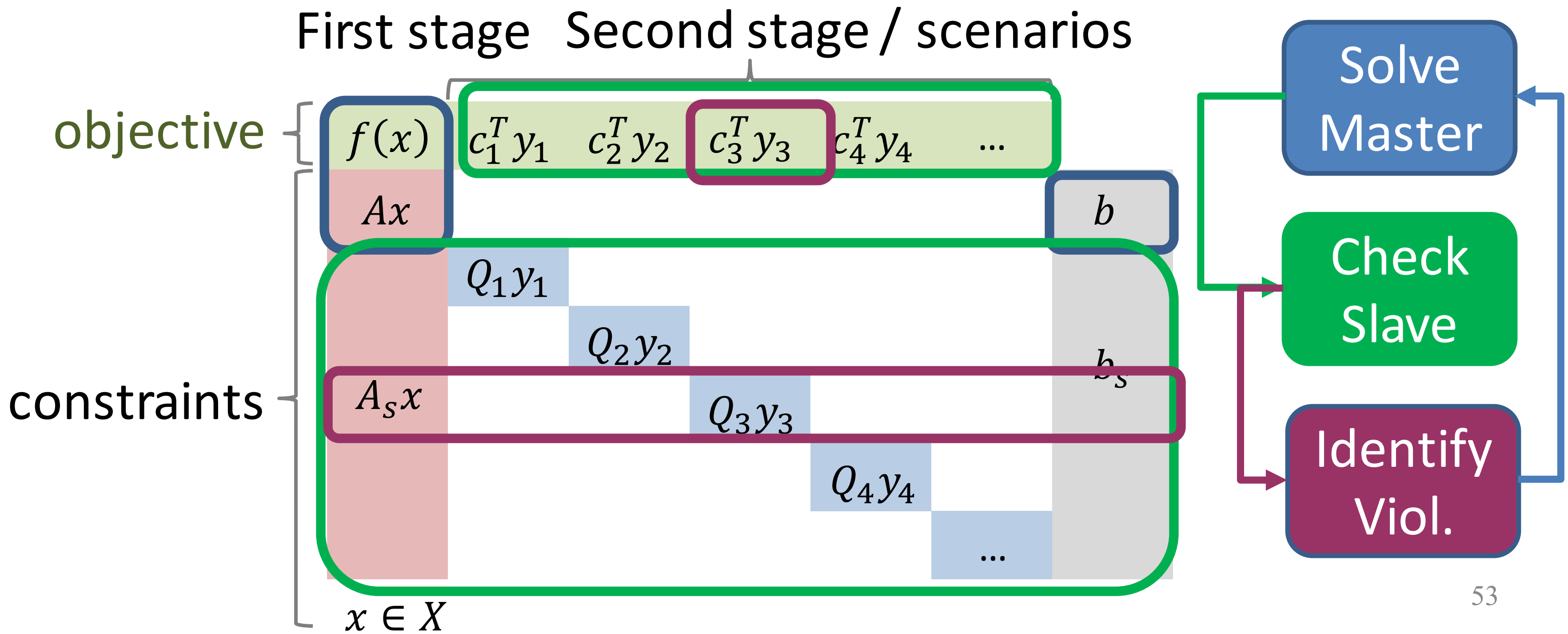
Non-anticipativity constraints:

- Link first stage decisions with second stage decisions
- For unit commitment: commitment status of non fast-start generators (generator *g*, period *t*, scenario *s*):

$$u_{gt} = u_{gts}$$

Block Diagonal Decomposition

- Two-stage stochastic programs
  - **Stage one** (x): base-case decisions made here and now
  - **Stage two** (y): recourse decisions that can be deferred
- **Obstacle I – Computational Complexity**
  - Size of the problem: OPF × Scenarios



Block Diagonal Decomposition

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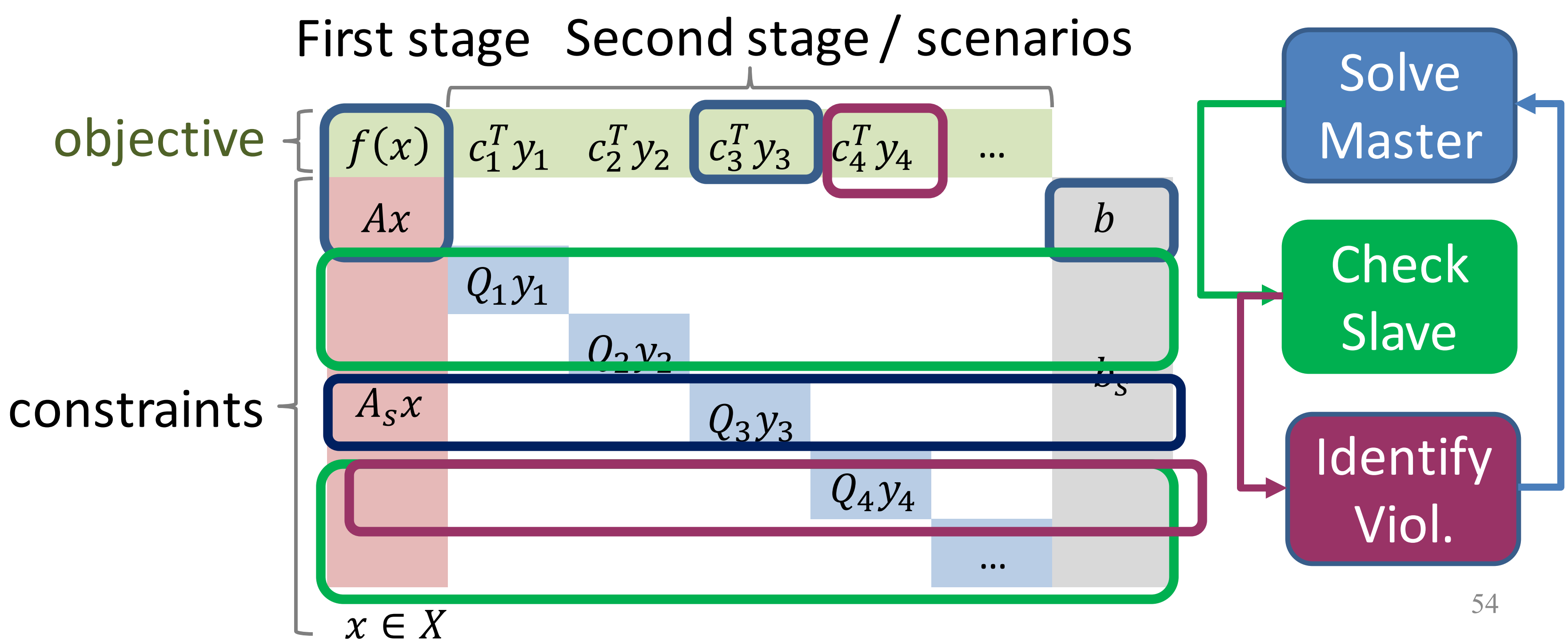

Block Diagonal Decomposition

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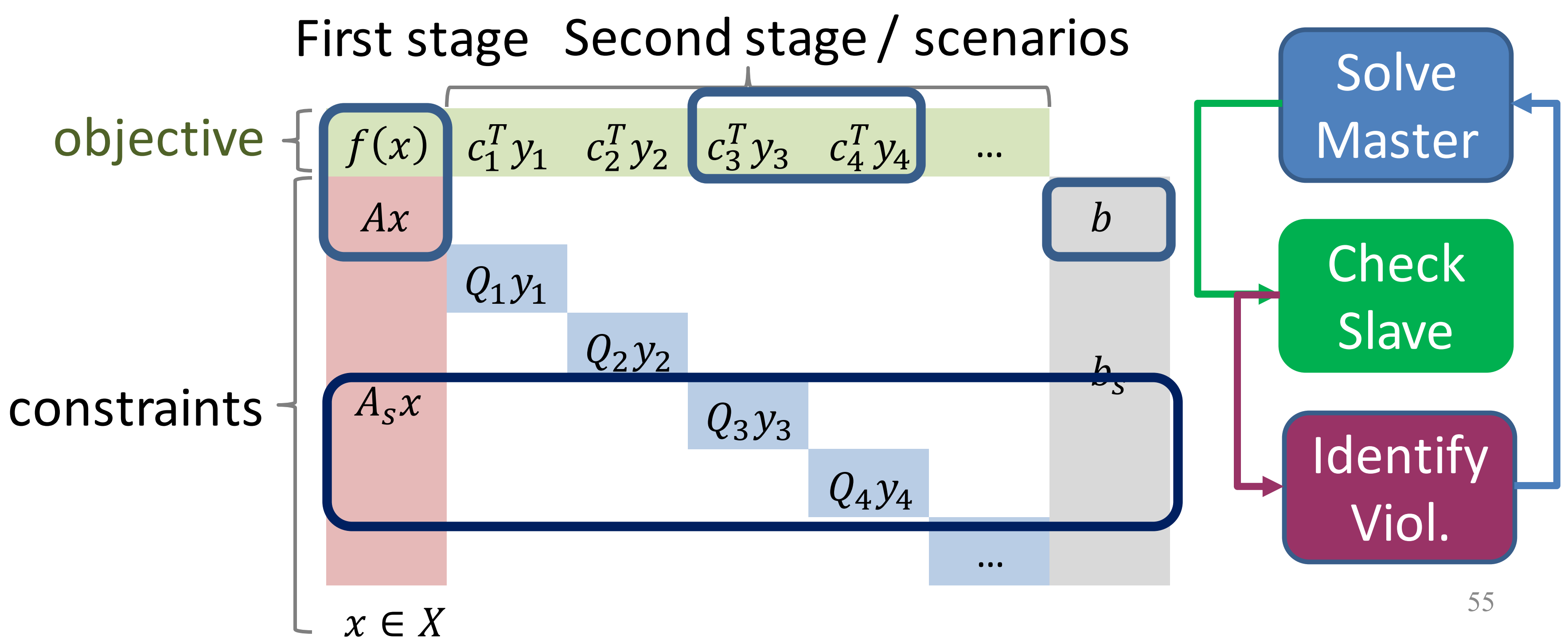

Block Diagonal Decomposition

Of course the hope is that you terminate before full expansion

- Two-stage stochastic programs
  - **Stage one** (x): base-case decisions made here and now
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- **Obstacle I – Computational Complexity**
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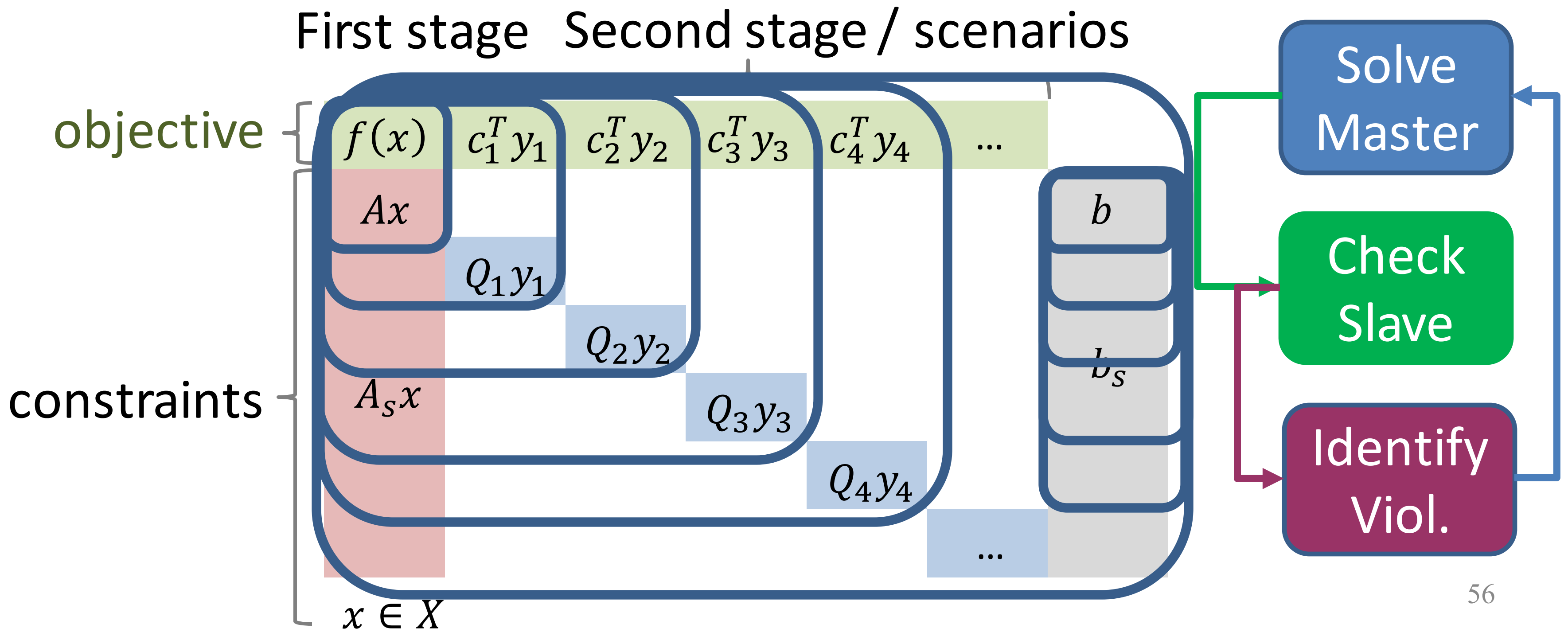


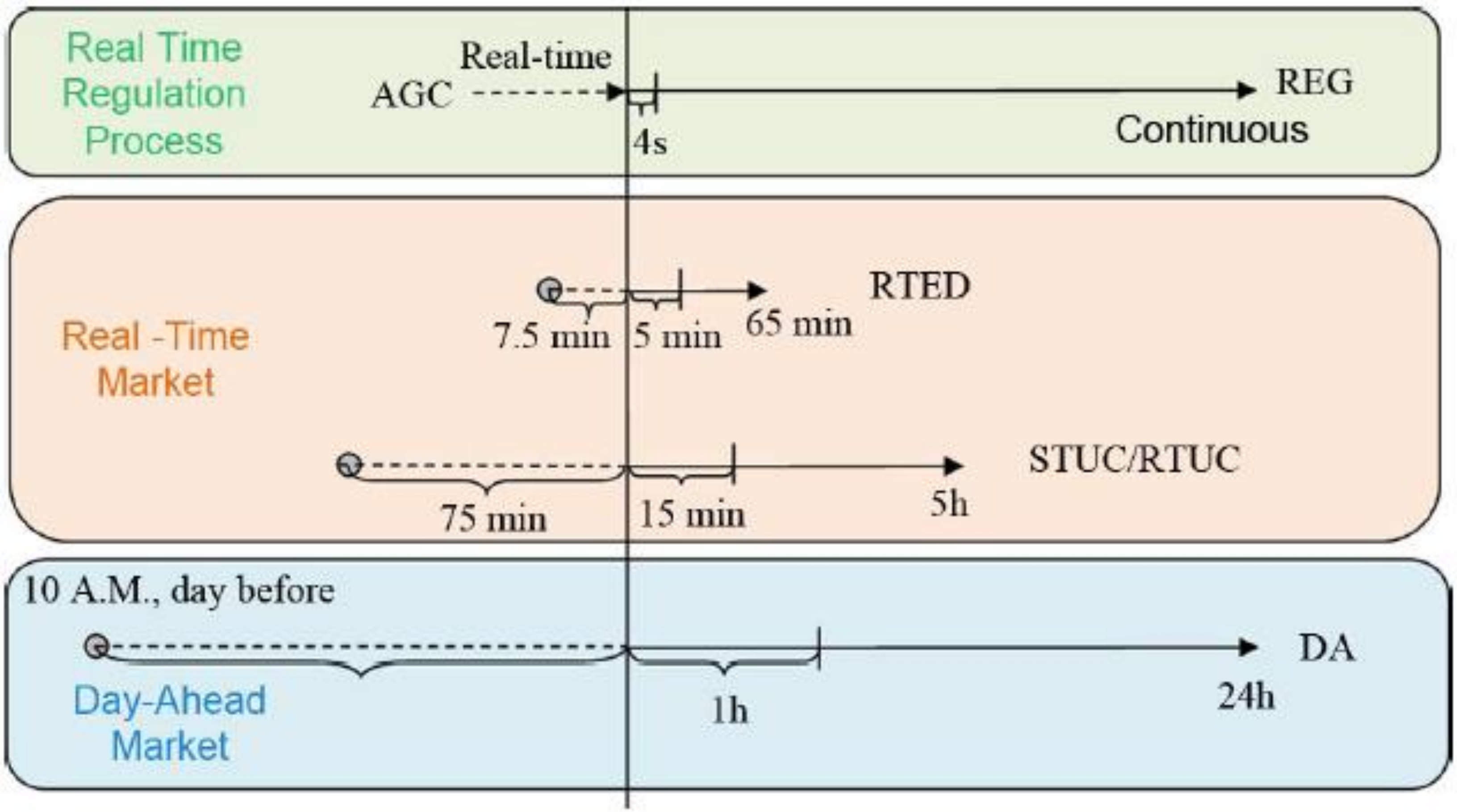
Break

Two Stage Programs

Challenges for Day-Ahead Scheduling & Markets

Operational Timeline

Source: Y. Makarov, et al., "Incorporating uncertainty of wind power generation forecast into power system operation, dispatch, and unit commitment procedures," *IEEE Trans. Sust. Energy,* 2011.



Preferred Day-Ahead Scheduling Problem for Energy Markets

Potential system size:

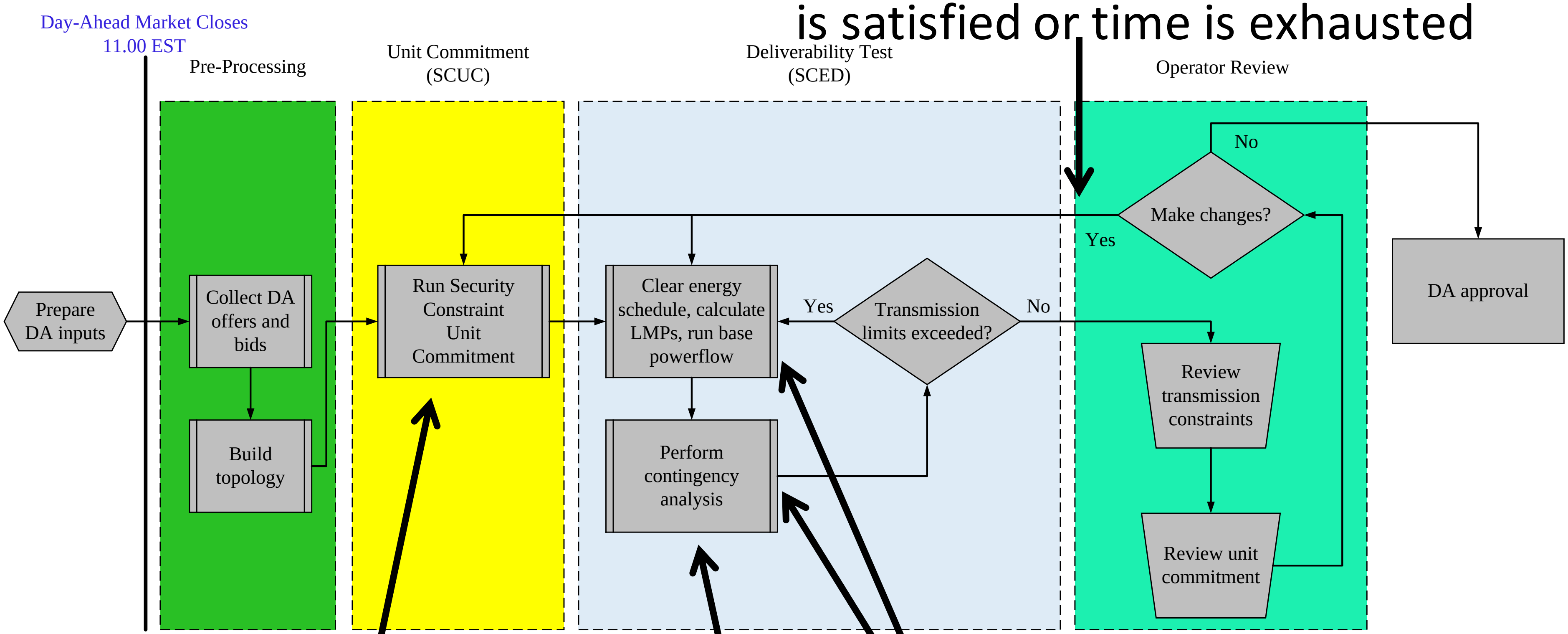
- 10,000 – 20,000 buses (nodes)
- >20,000 transmission lines (branches), transformer tap settings, flexible ac transmission systems devices, etc.
- Generators: 500-2000; flexible loads; virtual bidders (banks, financial institutions): thousands of bids
- Multiple day time horizon

Optimization problem: Stochastic mixed integer non-linear program (non-convex constraints)

Uncertainties: contingencies: >20,000; renewable (wind/solar) scenarios: >500; uncertain demand response: >?

Day-Ahead Scheduling in Midcontinent Independent System Operator (MISO)

Iterative process until operator is satisfied or time is exhausted



Mixed integer linear program

Reliability assessment

Linear program

MISO Day-Ahead Scheduling Procedure

[1] Aaron Casto, “Overview of MISO day-ahead markets,” *Midwest ISO*, [Online]. Available: http://www.atcllc.com/oasis/Customer_Notices/NCM_MISO_DayAhead111507.pdf.

Final Day-Ahead Market Solution

What is guaranteed within the market SCUC solution?

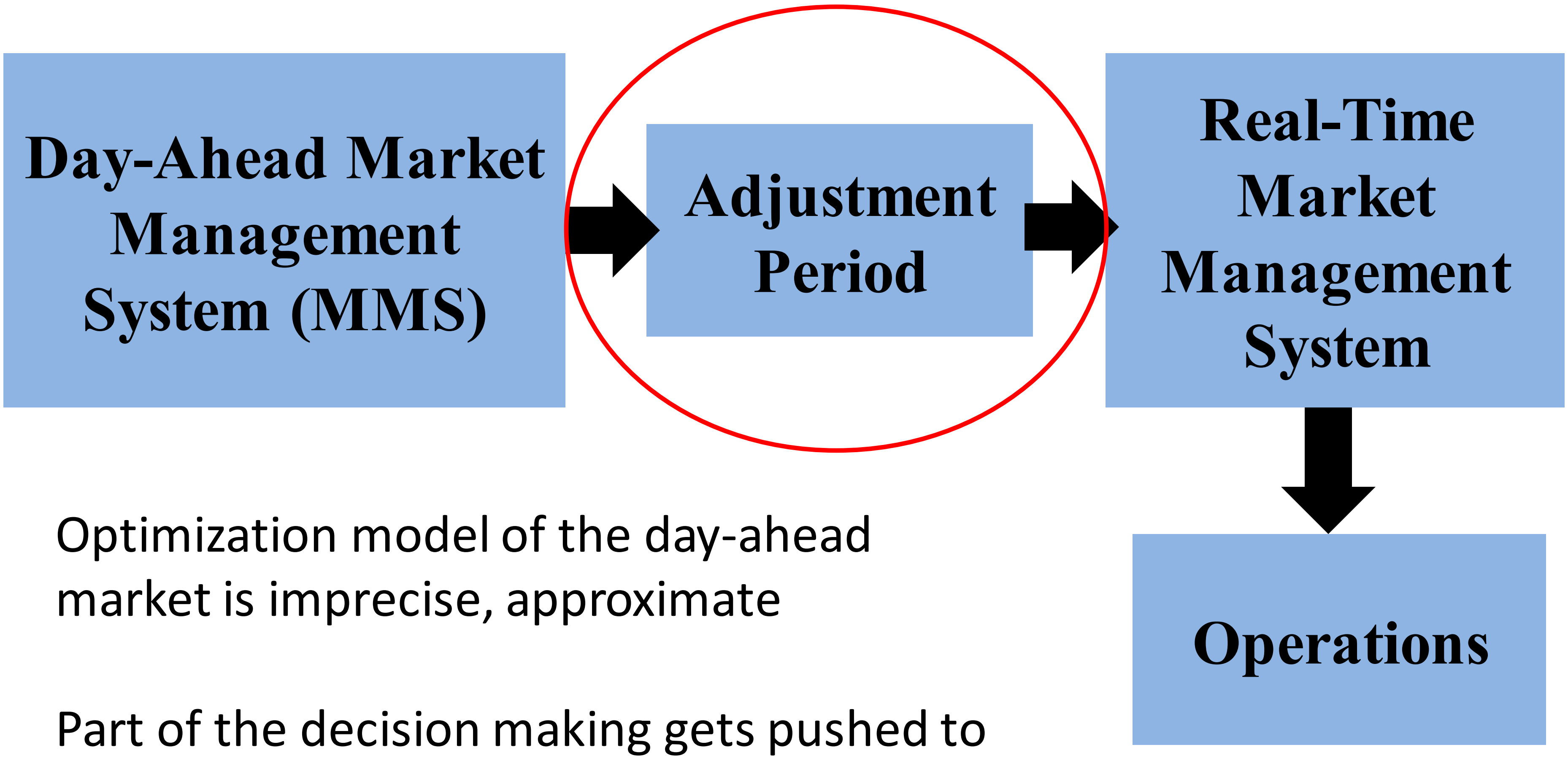
- AC feasible?
- N-1 Reliable?
- Renewable uncertainty?
- Stability?

Approximations within SCUC models result in either infeasible solutions that must be corrected outside of the market engine or overly conservative solutions

Existing Model Simplifications

- Modeled system size: out of 20k lines and as many as 30k contingencies, the number of monitored base case and post-contingency flow limitations are fewer than 10k
- MMS and Energy Management Systems (EMS) rely on many assumptions regarding system operating conditions
  - Which network flow constraints to impose; which to ignore
- Operators are observing never before seen flow patterns within the grid due to renewables (e.g., within BPA)
- Unprecedented levels of variability and uncertainty caused by renewables undermine such assumptions
  - More challenging to predict the operational limitations
  - Existing practices and software must be changed

Market Adjustment Process



Optimization model of the day-ahead market is imprecise, approximate

Part of the decision making gets pushed to the adjustment period – engineering / operator adjustment (not optimized) takes over to obtain feasibility

Adjustment Period

Market operators must adjust market solutions to create realistic, feasible solutions

- Many different terms: Uneconomic adjustments; supplemental dispatch; out-of-merit capacity; out-of-merit energy; exceptional dispatches; reserve disqualification; reserve downflags
- We call these adjustments: out-of-market corrections
- Accounting for such corrections is key when evaluating new algorithms (e.g., stochastic programs)

Break

Two Stage Programs

Separation between academic models and reality and what this means for the transition from deterministic to stochastic

Representation of the Network Flow Model

- The actual network flow model is approximated
- Key benefit of stochastic programming is the ability to **locate reserves on a nodal basis**
- With approximate network flow models, you get approximate solutions as to where to locate reserves

- Stochastic programming must not only overcome the complexity of modeling uncertainty but also the complexity to go from such coarse approximate network flow models to more precise network flow models
    - **Huge challenge**

Operating Reserve Quantity

- Ad-hoc rules
- Typical 10-minute operating reserve quantity requirements in SCUC/SCED:
  - Single largest contingency
  - Proportional to demand/renewables
- CAISO:
  - Largest contingency
  - 5% of load met by hydro + 7% load met by non-hydro

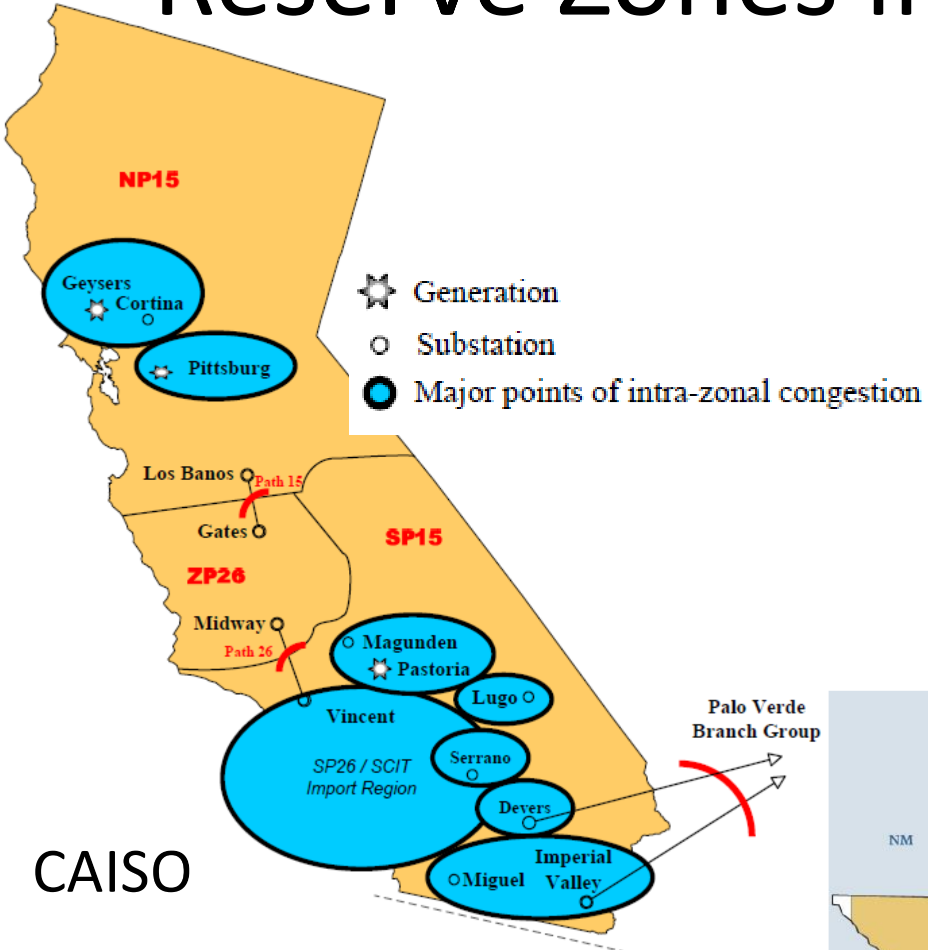
CAISO is the central auctioneer running the CA market and operating the CA grid

Reserve Location

- Stochastic programming
  - Implicitly locate reserve (and determine quantity)
  - Curse of dimensionality
  - Stakeholder issues; Pricing issues
- Reserve zones
  - Traditionally based on ad-hoc rules such as utilities ownership, or geographical boundaries, and treated as static
  - Blindly choose reserve inside reserve zones
  - It is assumed that reserve can be delivered without congestion inside the zone

Reserve Zones in Existing Markets

- CAISO has 3 reserve zones
- Their reserve rules do not account for intra-zonal congestion
- Intra-zonal congestion is account for by other rules

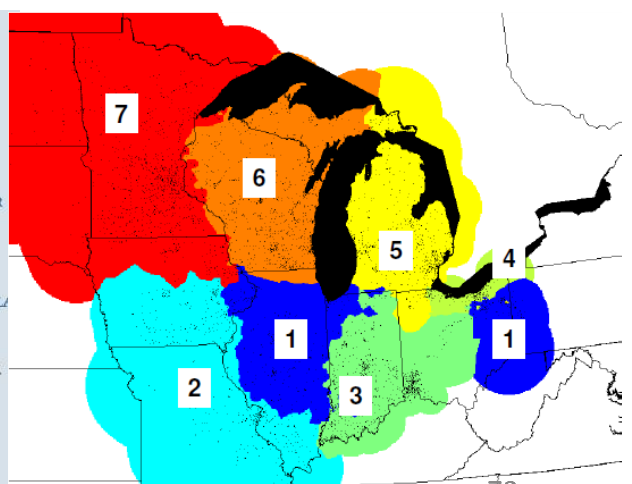


CAISO

ERCOT

Area 1 is a part of PJM

MISO



Advanced Algorithms

- Lagrange Relaxation
  - Used to be the main approach for deterministic SCUC before being replaced by MIP (e.g., B&B) based methods
  - Now being considered to assist with stochastic SCUC
- Benders' Decomposition
- Progressive Hedging (an augmented Lagrangian approach)
- ADMM (another augmented Lagrangian approach)
  - Alternating Direction Method of Multipliers

Summary

- Model complexity will grow with computational capability
- Smart, well-designed reserve policies will benefit near-term operations and future advances
- Expert systems balanced with advanced optimization algorithms
  - Can improve efficiency while also improving scalability
- Commercial grade changes to planning, operational planning, and real-time operational optimization software will include such expert system based approaches; there will not be a direct jump to stochastic programming