Fall 10-24-2012

Primary Frequency Response Ancillary Service Market Designs

Erik Ela
NREL

National Renewable Energy Laboratory
Innovation for Our Energy Future

Primary Frequency Response Ancillary Service Market Designs

Erik Ela

Erik.Ela@nrel.gov

Modeling, Simulation and Optimization for the 21st Century Electric Power Grid

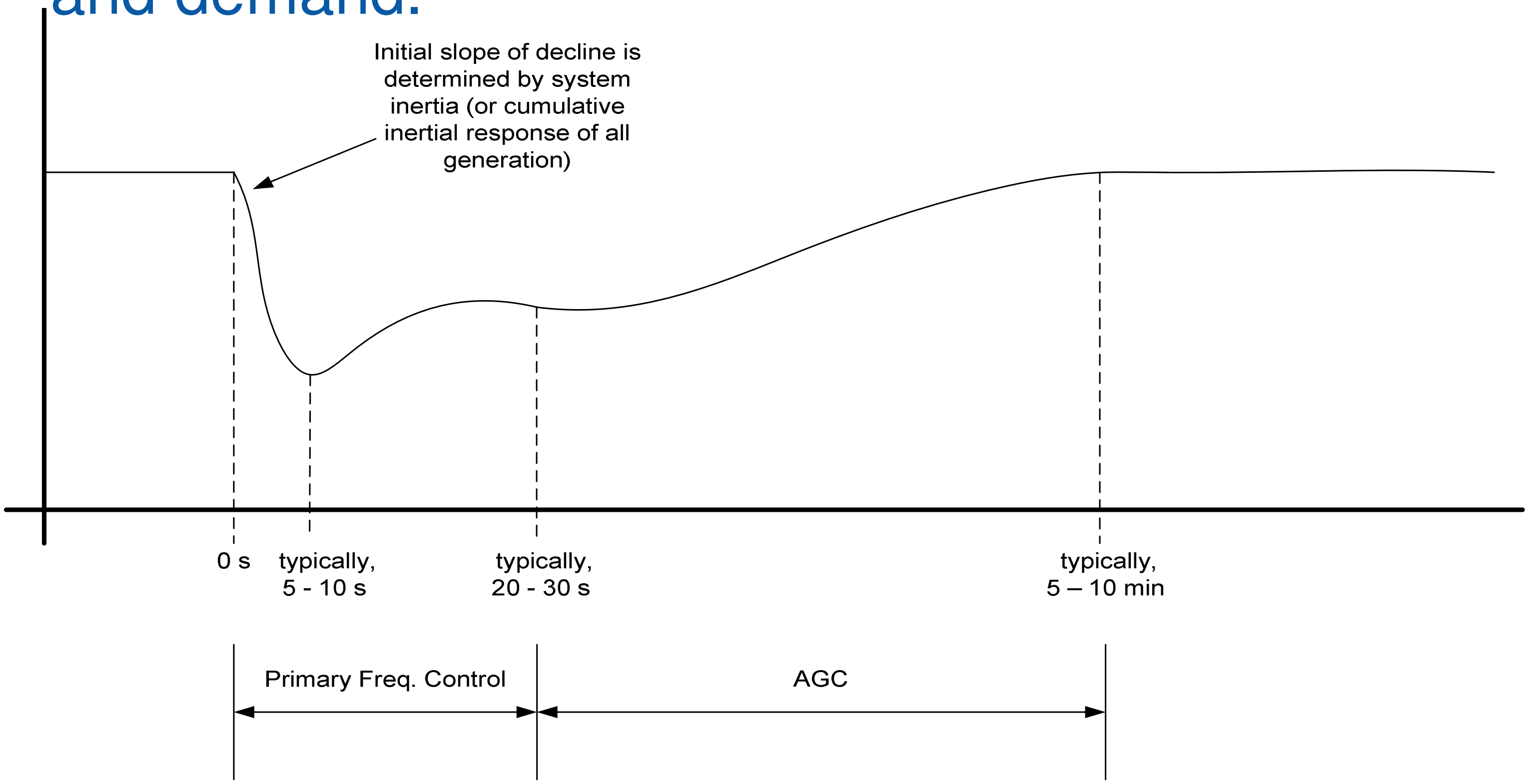
October 24, 2012

Overview

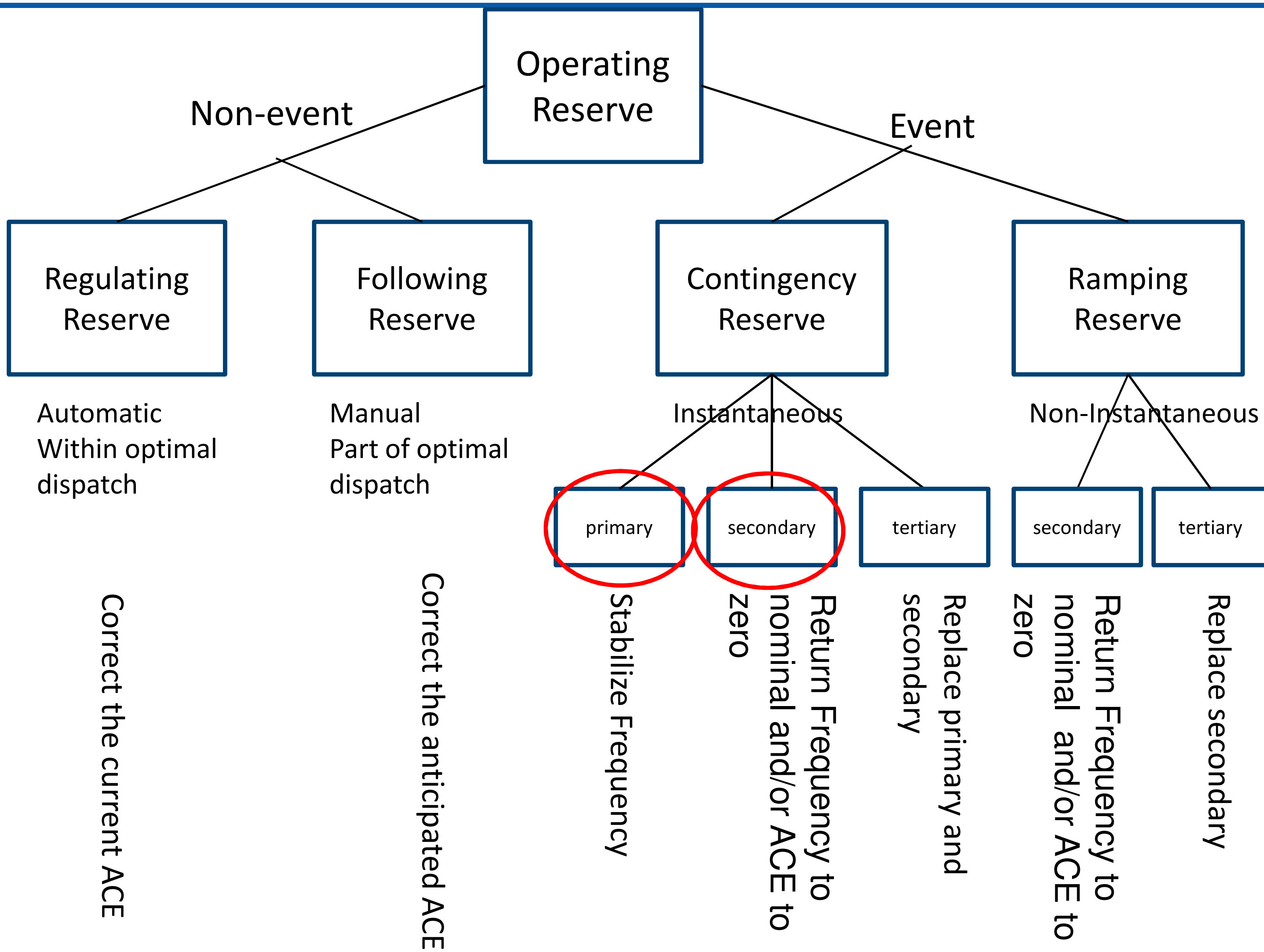
- Motivation
  - Frequency response decline
  - Emergence of electronically-coupled new technologies without PFR capabilities
  - Present disincentives, lack of incentives, market behavior
- PFR Market Design (preliminary)
  - Market clearing engine
  - Pricing mechanism
- Case Studies (preliminary)

Frequency

Electrical frequency – Interconnection balance of supply and demand.



Primary and Secondary Reserve



Ela, Milligan, and Kirby "Operating Reserves and Variable Generation" NREL/TP-550-51928, August 2011.

Decline in response

Ingleson 2010, Ingleson 2005

Decline on the Eastern Interconnection of about 60-70 MW/0.1Hz/year

Reasons:

- High governor dead bands
- operating mode (sliding pressure)
- Blocked governors

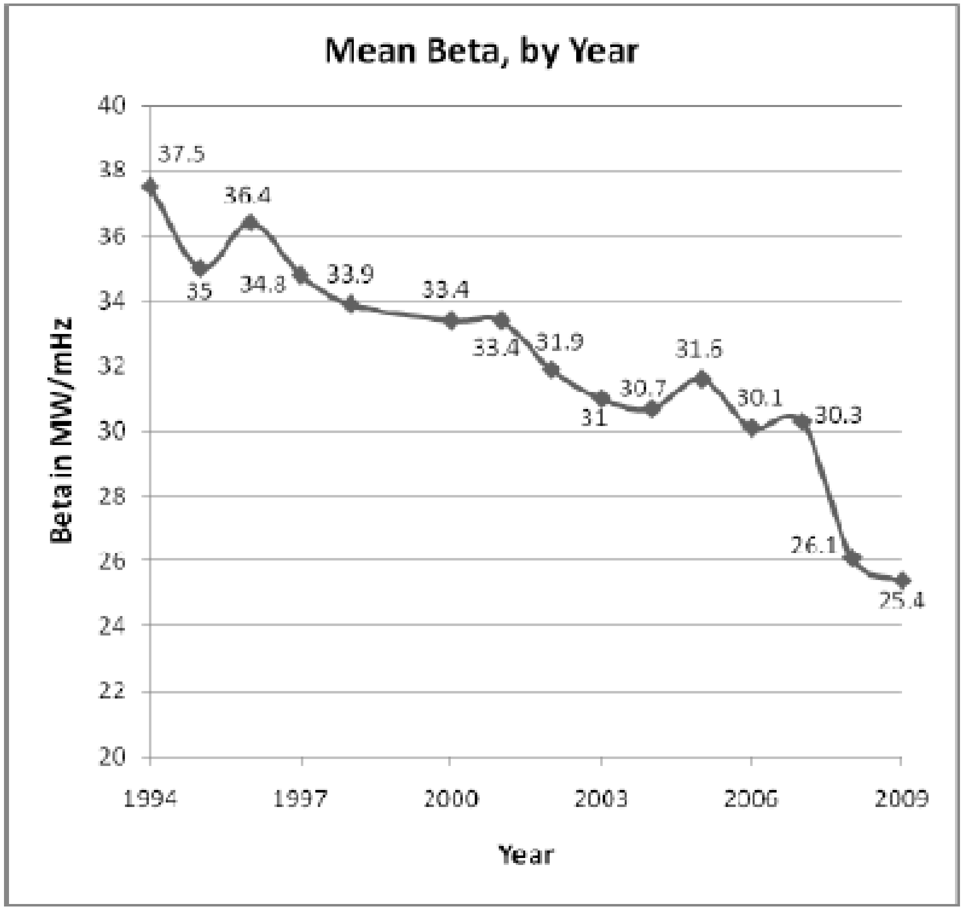
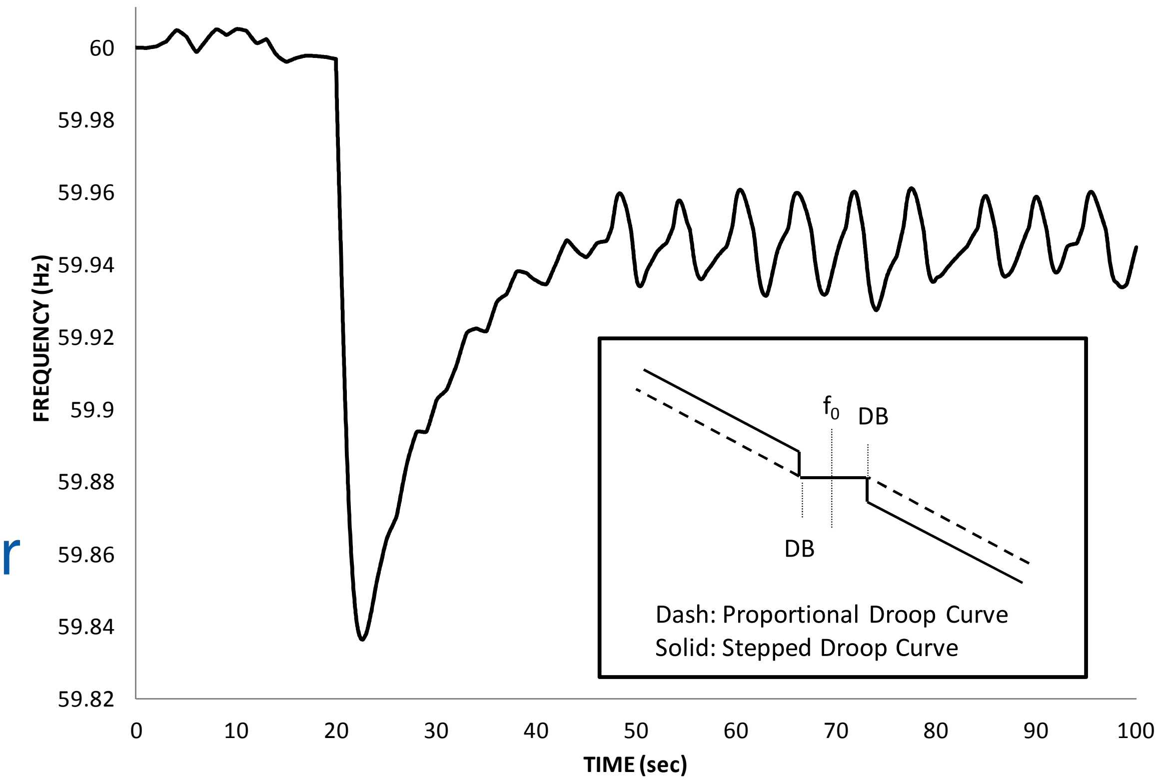


Fig. 2. Mean Beta computed for each year from 1994 through 2009. Data are not complete for the year 1999, so that year is omitted from this plot.

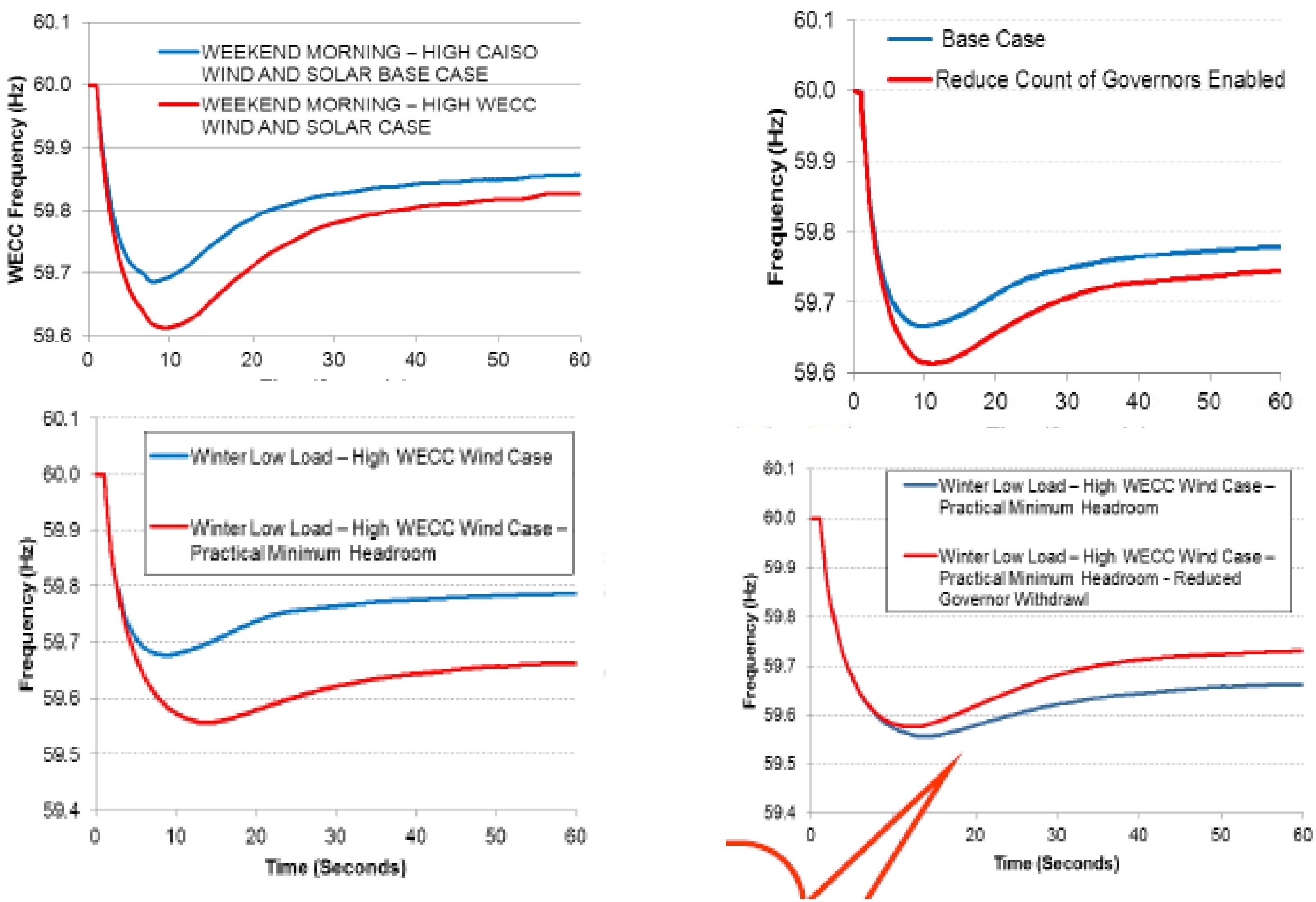
Decline in response

Other issues:

- Governor withdrawal
- Oscillatory behavior (stepped droop curves)
- Slow response
- Insensitive dead bands

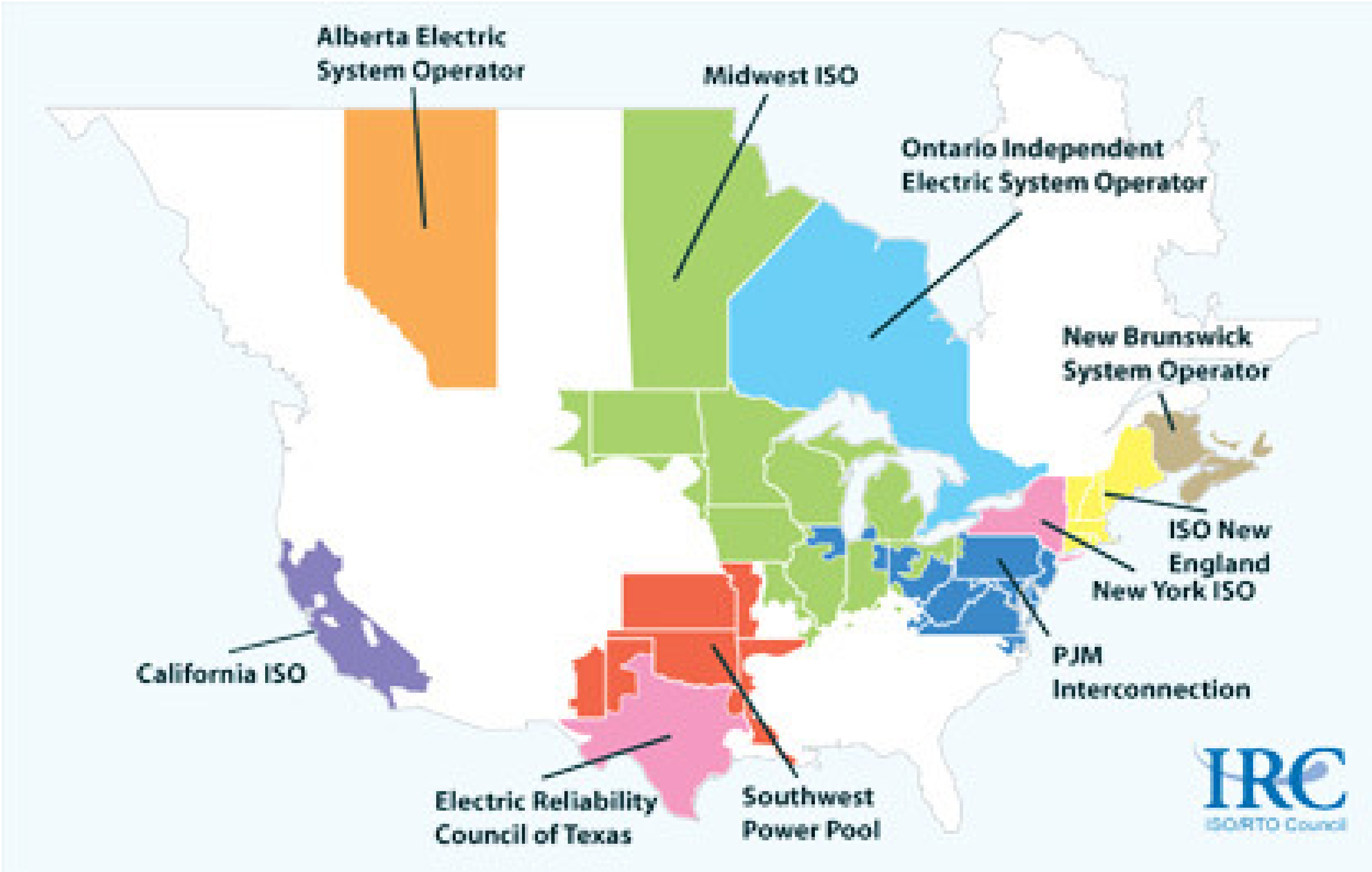


High renewable scenarios



N. Miller, “CAISO Frequency Response Study,” UVIG April 2012.

North American Energy Markets



Pool-based SMD: 2 settlements, locational marginal pricing, Energy is co-optimized with spinning reserve, nonspinning reserve and regulation reserve

Frequency Bias

Bias (MW/0.1Hz) is not Frequency Response (MW/0.1Hz)!!

$$ACE = NI_A - NI_S - 10B(F_A - F_S)$$

Scenario 1

NI_S = 500 MW
F_S = 60 Hz
B = -200 MW/ 0.1 Hz

NI_A = 600 MW
F_A = 60 Hz
ACE = 100 MW

Scenario 2

NI_S = 500 MW
F_S = 60 Hz
B = -200 MW/ 0.1 Hz

NI_A = 600 MW
F_A = 59.95 Hz
ACE = 0 MW

Disincentives

3% Penalty Band over generation schedule

60 Hz system

5% Droop curve setting

0 Hz Dead band

$$\frac{1\ p.u.power}{0.05\ p.u.frequency} = \frac{0.03\ p.u.power}{X\ p.u.frequency}$$

$$X = 0.0015\ p.u.frequency = 90\ mHz\ for\ a\ 60Hz\ system$$

Any deviation greater than 90 mHz, a generator **automatically** will be penalized with a functioning turbine governor enabled!

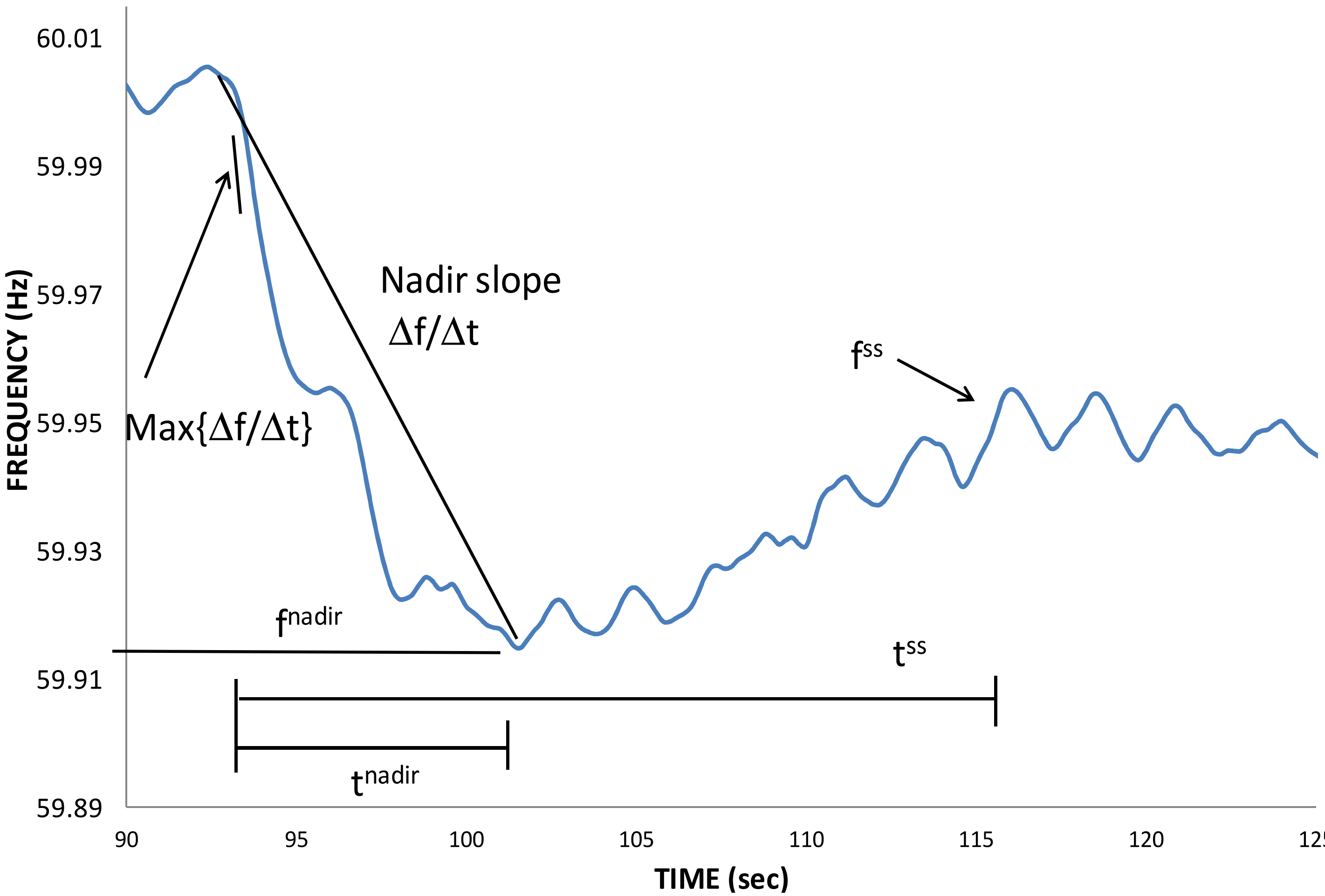
E. Ela, A. Tuohy, M. Milligan, B. Kirby, and D. Brooks, "Alternative approaches for a frequency responsive reserve ancillary service market," *The Electricity Journal,* vol. 25, no. 4, pp. 88-102, May 2012.

Need for incentives

IEEE Task Force on Large Interconnected Power Systems Response to Generation Governing, *Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns*, IEEE Special Publication 07TP180, May 2007.

"…this requirement provides impetus to the approach of a reward based method of monitoring and providing financial incentive for governing response. This observation is the root of the purpose of the Task Force, to address the conflicting pulls of lowest possible cost of electricity without risking the costs of a system blackout."

Linking the reliability requirements



Scheduling

1. Ensure resources are providing enough synchronous inertia so that Max {Δf/Δt} does not exceed a limit that can cause triggering of ROCOF relays or lead to instability or triggering of UFLS

$$\sum_{i=1}^{NG}\{u_{i,t} * H_i * S_i^{max}\} + H_L^{eq} * L_t \geq I_A^{Req} \quad \forall t \in NT$$

2. Ensure enough PFR capacity is available

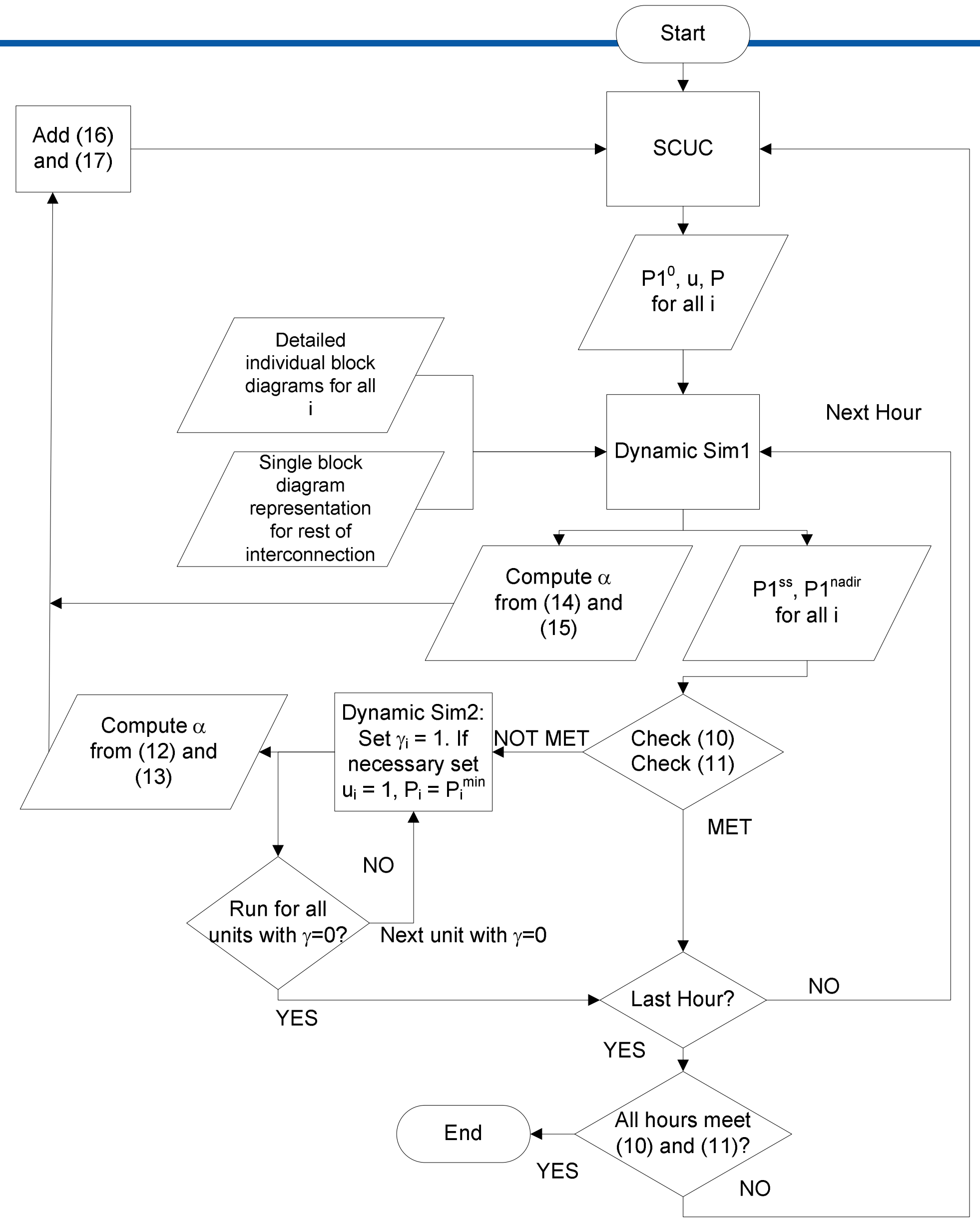
$$\sum_{i=1}^{NG} P1_{i,t}^{0} \geq P1_A^{0Req} - D * L_t \quad \forall t \in NT$$

Scheduling

3. Ensure PFR is sensitive enough to frequency to avoid triggering of UFLS and to limit the deviation of f^{ss} from nominal, as well as limiting insensitivity
   - Equivalent droop curves to capacity based on maximal
   - Head room availability: χ – binary variable
   - Consider governor dead bands
   - Governor enablement
   - If governors are too high, they are not acceptable

Scheduling

4. Ensure that PFR is triggered fast enough to avoid UFLS and that it is fully deployed within a time limit (t^{ss}) to ensure stability and limit risk



Scheduling

5. Ensure that PFR response is stable and does not cause instability or oscillatory frequency behavior.
6. Ensure a sustainable PFR, so that after reaching f_{ss} there is a constant recovery with no withdrawal of PFR when secondary reserve is deployed to recover frequency.

Pricing

$$\mathcal{L} = \sum_{i=1}^{NG} C_i P_i - \lambda * \left(\sum_{i=1}^{NG} P_i - L - Loss\right) - \sum_{l=1}^{NL} (\mu_l * \left(\sum_{n=1}^{NB} SF_{n,l} * (P_n - L_n) - PL_l\right) - \psi * \left(Loss - \sum_{n=1}^{NB} LF_n * (P_n - L_n)\right) - \sum_{r=1}^{NR} \beta_r * \left(\sum_{i=1}^{NG} Pres_i - R\right)$$

$$LMP_n = \frac{\partial \mathcal{L}}{\partial L_n} = \lambda + \sum_{l=1}^{NL} \mu_l * SF_{n,l} - \lambda * LF_i$$

$$RCP = \frac{\partial \mathcal{L}}{\partial R} = \beta$$

Pricing Hierarchy

PFR^{nadir} ->

PFR^{SS} -> $P2^{spin}$ -> $P2^{nonspin}$

PFR^{0} ->

Pricing

Synchronous Inertia requirement is discrete sensitivity.

Increasing I^{req} an infinitesimal has no marginal cost.

With marginal pricing concept, there is always a zero price, and no incentives to provide synchronous inertia

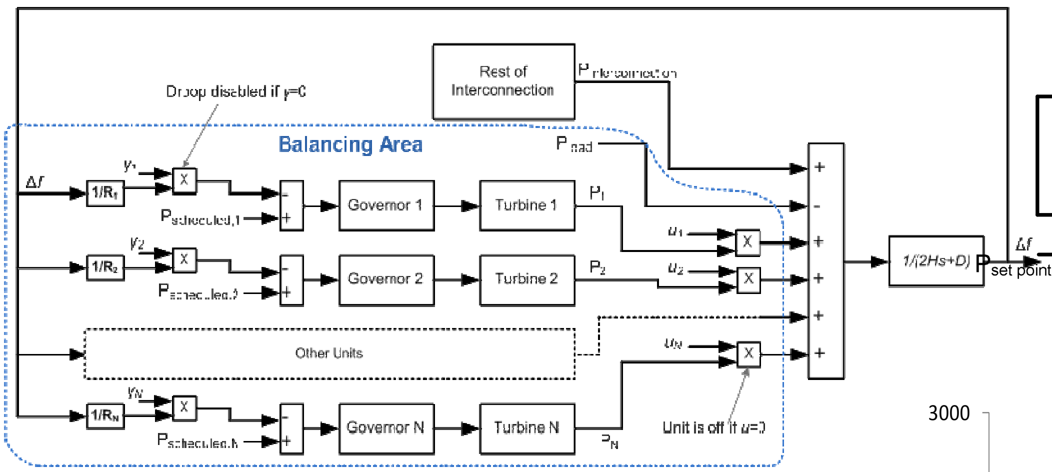
Hybrid pricing (NYISO) and ELMP (MISO) for energy pricing of gas turbines concept

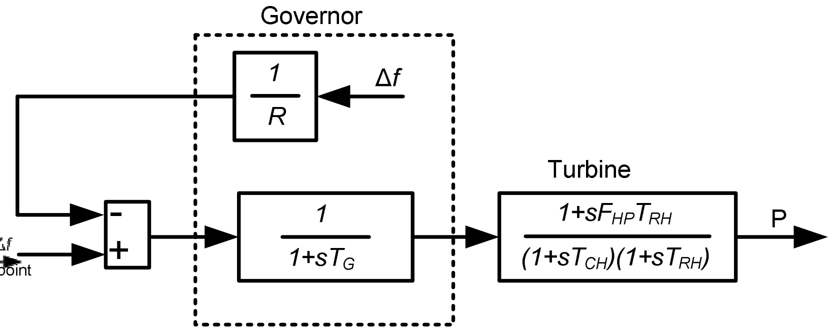
Integrality constraint relaxed for pricing of synchronous inertia (no change in schedule)

Key concepts

- Incorporate these constraints into SCUC model using MILP
- How pricing affects revenues and uplift
- Incentivizing response that is not simply capacity
- Links to the reliability constraints needed for sufficient frequency response on the interconnection
- Applicable to systems which are part of large synchronous interconnections and isolated systems.
- Reduces uplift when resources are needed for reliability.
- True physical representation of the PFR capabilities

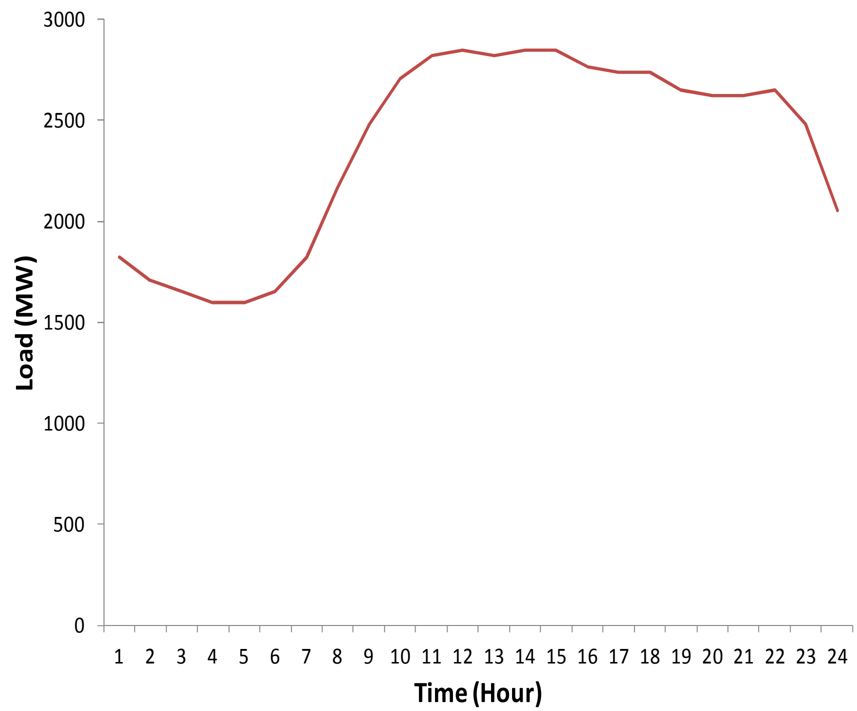
Test System





$T_G = 0.2$ s, $T_{CH} = 0.3$ s, $T_{RH} = 7.0$ s, $F_{HP} = 0.3$

Unit	*H (s)*	*R (p.u.)*	*DB (mHz)*
U12	2.6	.05	36
U20	2.8	.05	36
U50	3.5	.05	36
U76	3.0	.05	36
U100	2.8	.05	36
U155	3.0	.05	36
U197	2.8	.05	36
U350	3.0	.05	36
U400	5.0	.05	36



•Reliability Test System Task Force, "The IEEE reliability test system—1996," *IEEE Trans. Power Syst.*, vol. 14, no. 3, pp. 1010-1020, Aug. 1999.

Case Studies

$P1_A^{0Req}$ (MW)	$P1_{A\ Req}^{Nadir}$ (MW)	Δf^{max} (Hz)	I_A^{Req} (MVAs)	$P2^{Req}$ (MW)	DB^{max} (Hz)
44	33	0.2	5500	120	0.1

t^{ss} (s)	t^{nadir} (s)	t^{rec} (min)
30	4	10

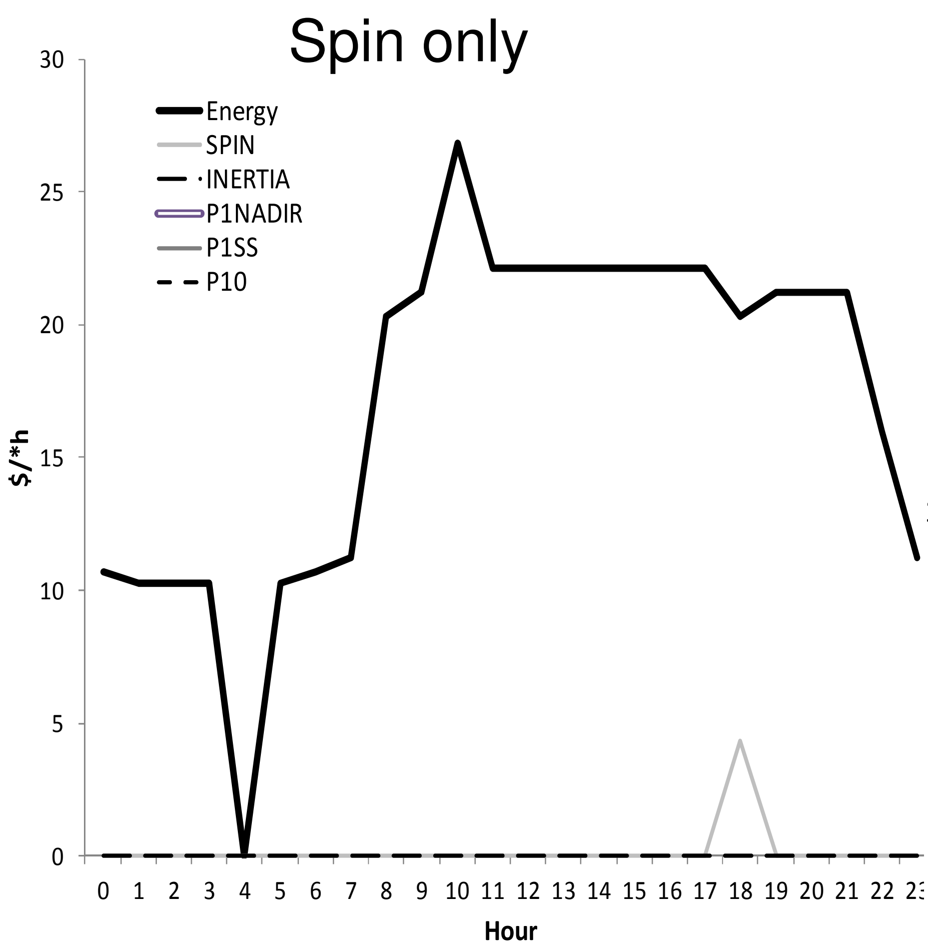
Base Case Comparison

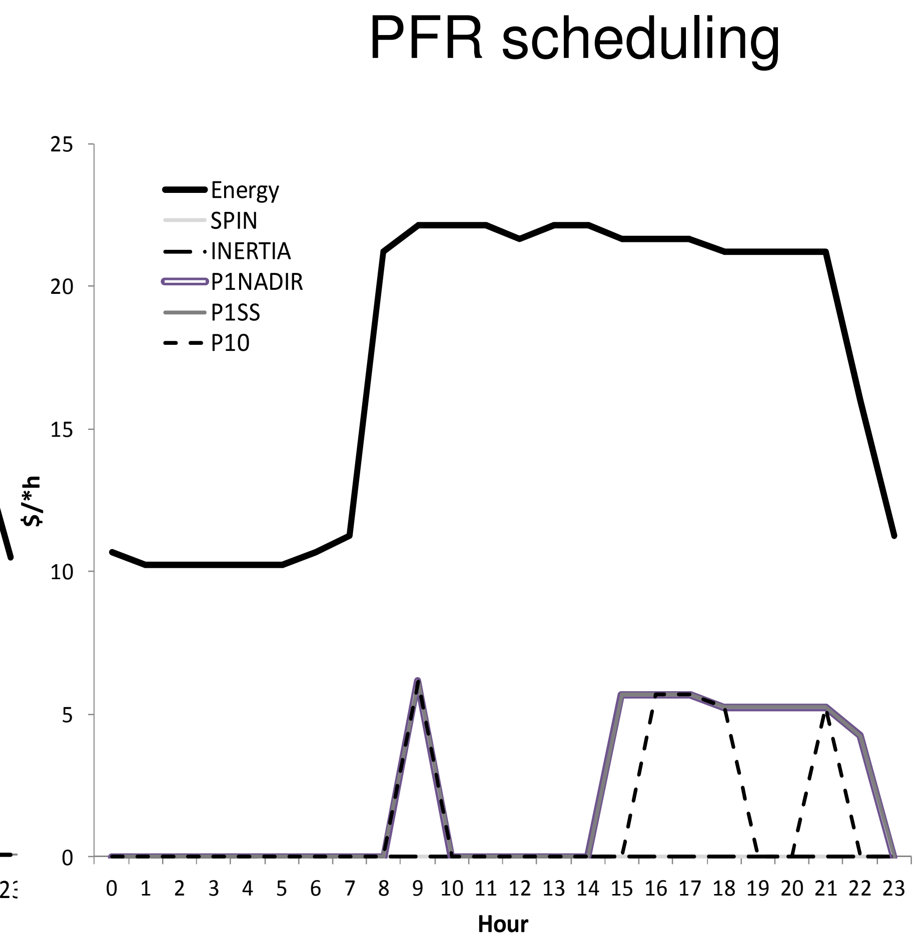
	BC1	BC2
Production Costs ($)	568,297	569,315
Avg. Units online	20	19
Avg. inertial energy (MVAs)	8563	8618
Avg. $P1^{ss}$ (MW)	43.7	48.4

15% Wind Case Comparison

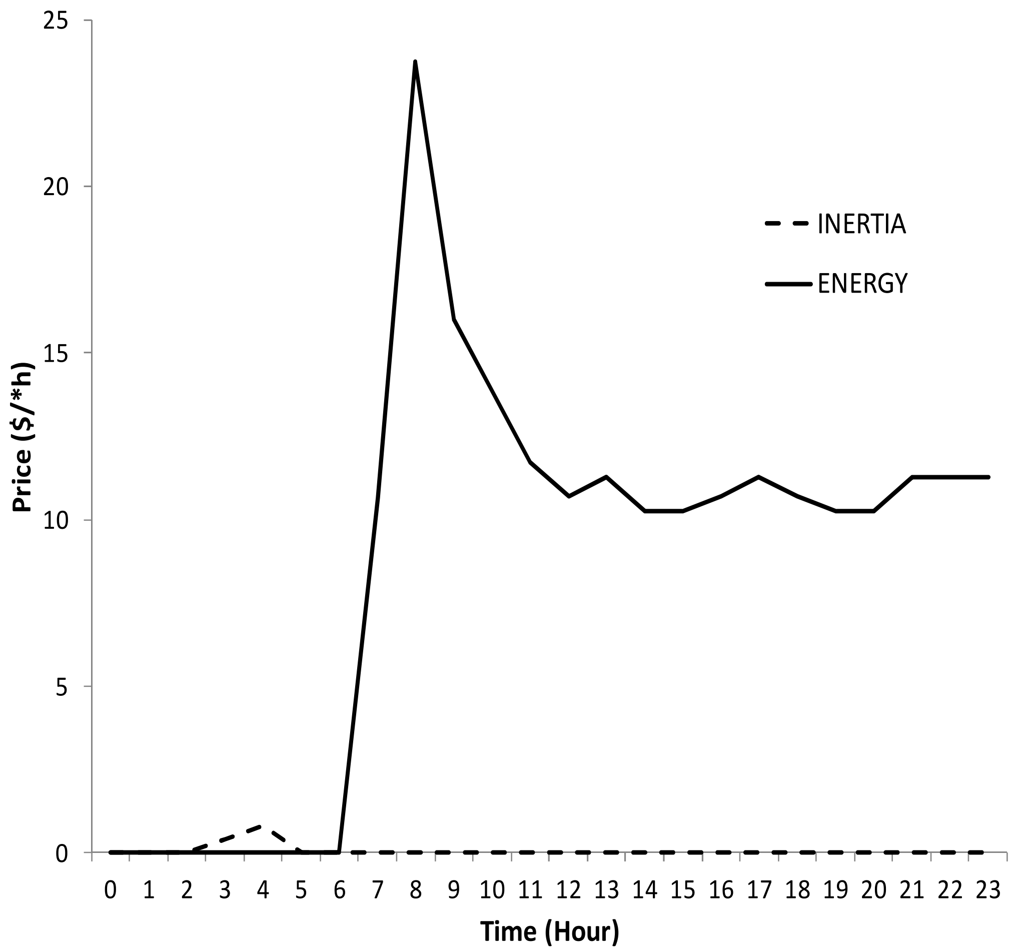
	WC1	WC2
Production Costs($)	401,287	403,616
Avg. Units online	17	17
Avg. inertial energy (MVAs)	7283	7310
Avg. $P1^{ss}$ (MW)	36.75	48.1

Case Studies





Uplift reduction



13% reduction in uplift

Incentivizing

Sensitivity to PFR characteristics

	Total Energy Payment ($)	Total PFR Payment ($)	Total Cost ($)	Total Rev. = Payment – Cost ($)	Change in Rev. vs. Base Case $ / %
Base Case	87,277	333	71,256	16,355	-
Reducing *R* to 4%	96,337	496	71,108	25,725	9,370 / 57%
Reducing *DB* to 10 mHz	93,789	587	71,089	23,287	6,932 / 42%

Conclusions

- Lack of incentives might be leading cause to frequency response declines
  - Ancillary service market might be logical next step with new BAL-003
- Very minor changes when incorporating PFR characteristics on today's system
  - Change likely on blocking of governor systems and high governor dead bands
- Larger change on systems with high penetrations on PFR-incompatible resources
  - Could incentivize these resources to install capabilities
- Uplift is reduced, resources are incentivized to be online for PFR capabilities only
- Resources are incentivized for improvements for various PFR capabilities, goal of market design.

Questions?

Erik.Ela@nrel.gov