Challenges for Balancing Area Coordination Considering High Wind Penetration

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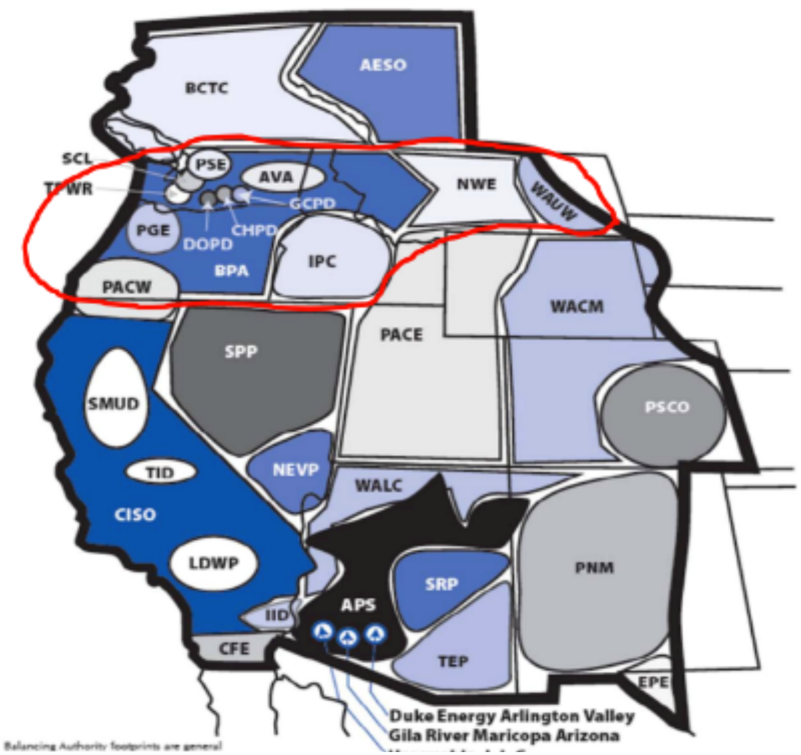
Outline

- Motivation
- Background
- Initial Results
- Future Work

Motivation

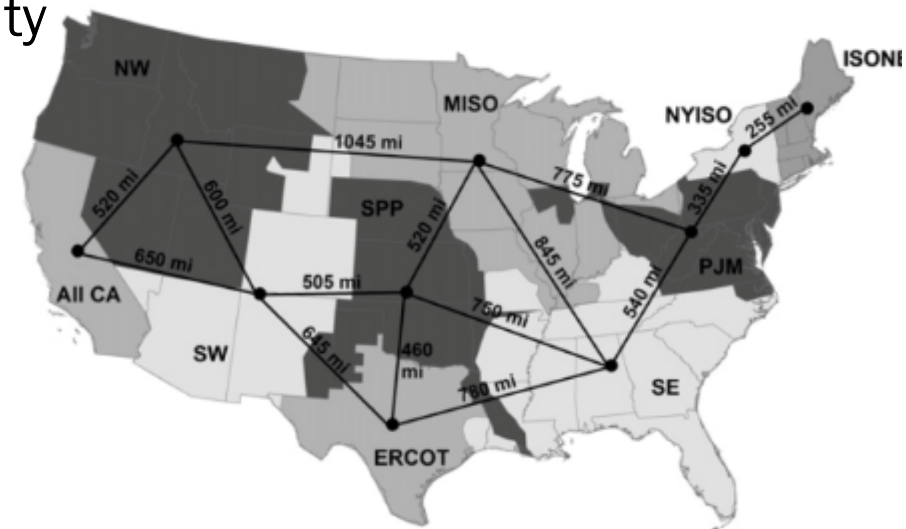
- Renewables add variability to system operations
- Balancing area (BA) consolidation has been proposed
- Wind, load diversity reduce impact of variability
  - Better resource use
    - Reserve
    - Unit scheduling
  - Decrease peak generation & ramping needs



M. Milligan, B. Kirby, and S. Beuning, "Combining Balancing Areas' Variability: Impacts on Wind Integration in the Western Interconnection," in *WINDPOWER Conference and Exhibition*, 2010.

Motivation

- Tradeoffs
  - System size (more nodes & variables) makes solving to optimality more difficult
  - Increasing complexity in systems operations (ex: stochastic UC)
- Most dramatic results are seen in studies with large consolidation
- Does not address uncertainty
  - What's more valuable?
- Challenge of merging different policies, rules, and regulations



B. A. Corcoran, N. Jenkins, and M. Z. Jacobson, "Effects of aggregating electric load in the United States," *Energy Policy*, vol. 46, pp. 399–416, Jul. 2012.

Questions

- Assuming full integration is not an option:
  - How can we incent efficient coordination & trade?
  - What coordination comes closest to integration?

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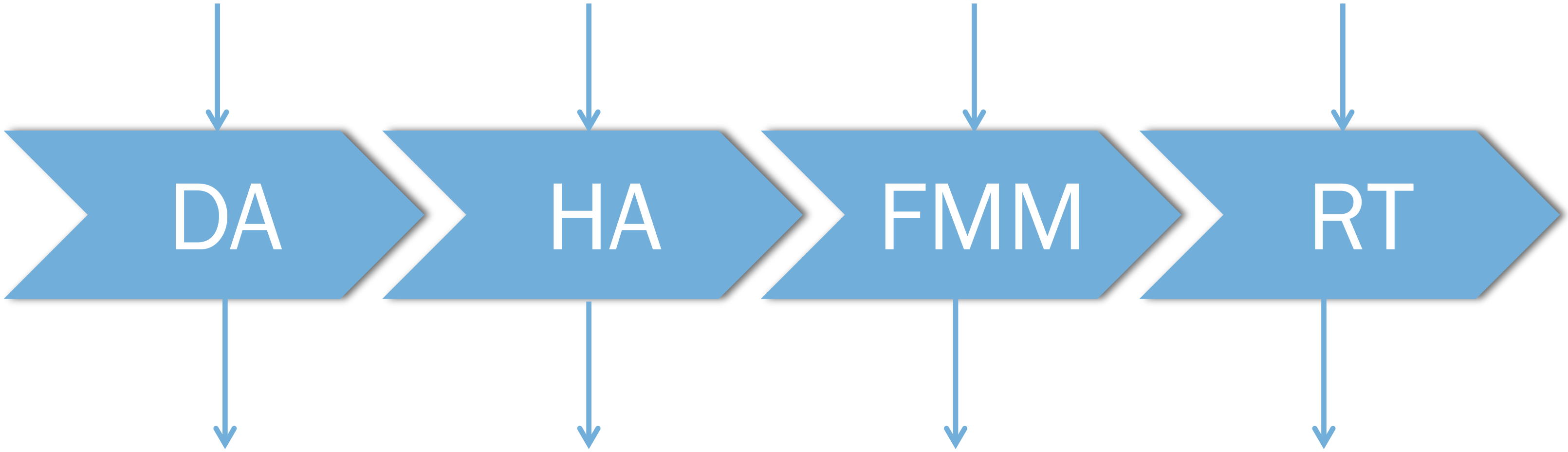
General Market Timeline

Load & renewable forecasts, generation bids, fixed schedules, updates



Resource schedules (commitment, energy, ancillary services), prices, reliability checks

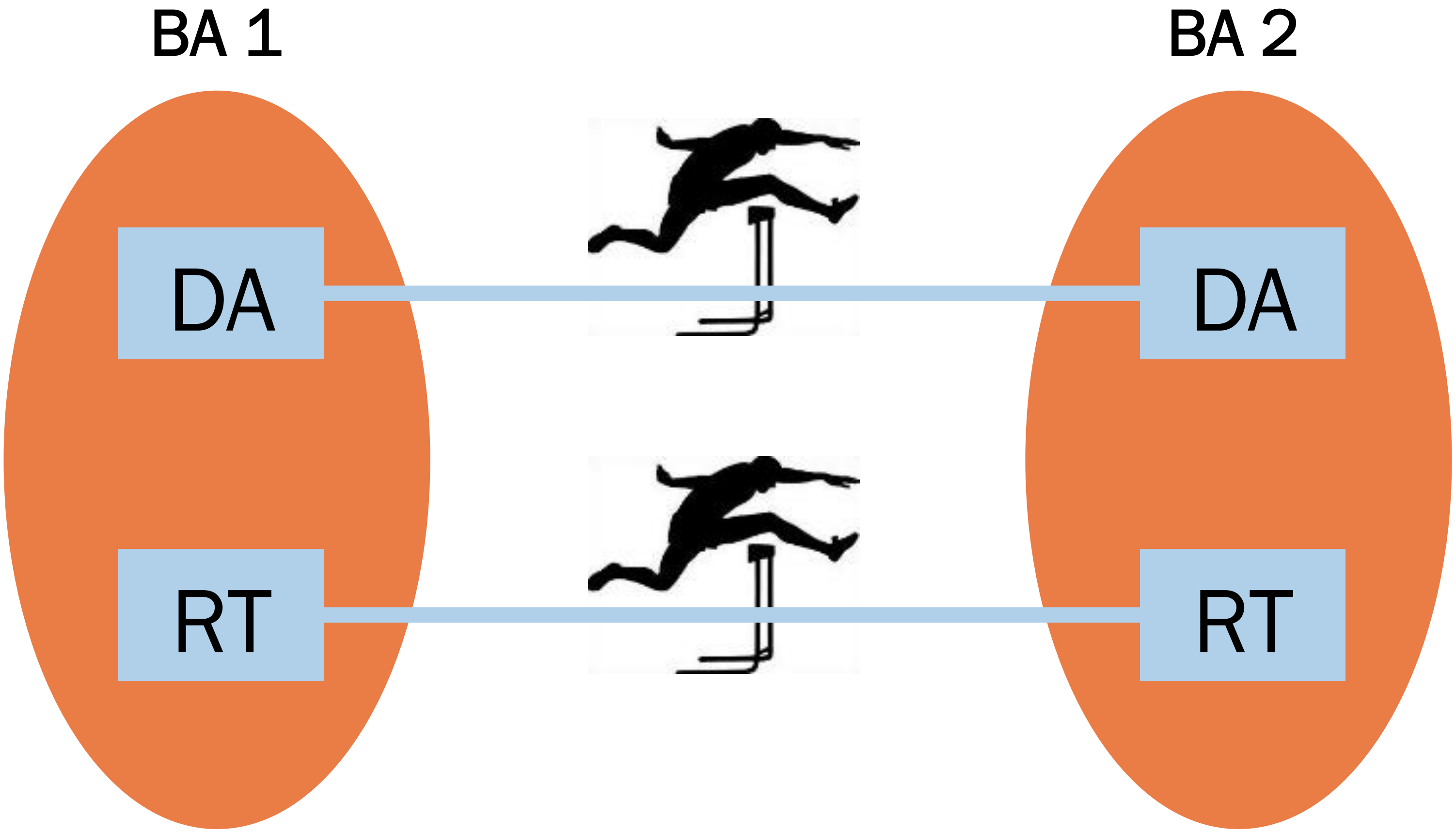
DA = Day-Ahead, HA = Hour-Ahead,
FMM = Fifteen Minute Market, RT = Real-Time

Hurdle Rates

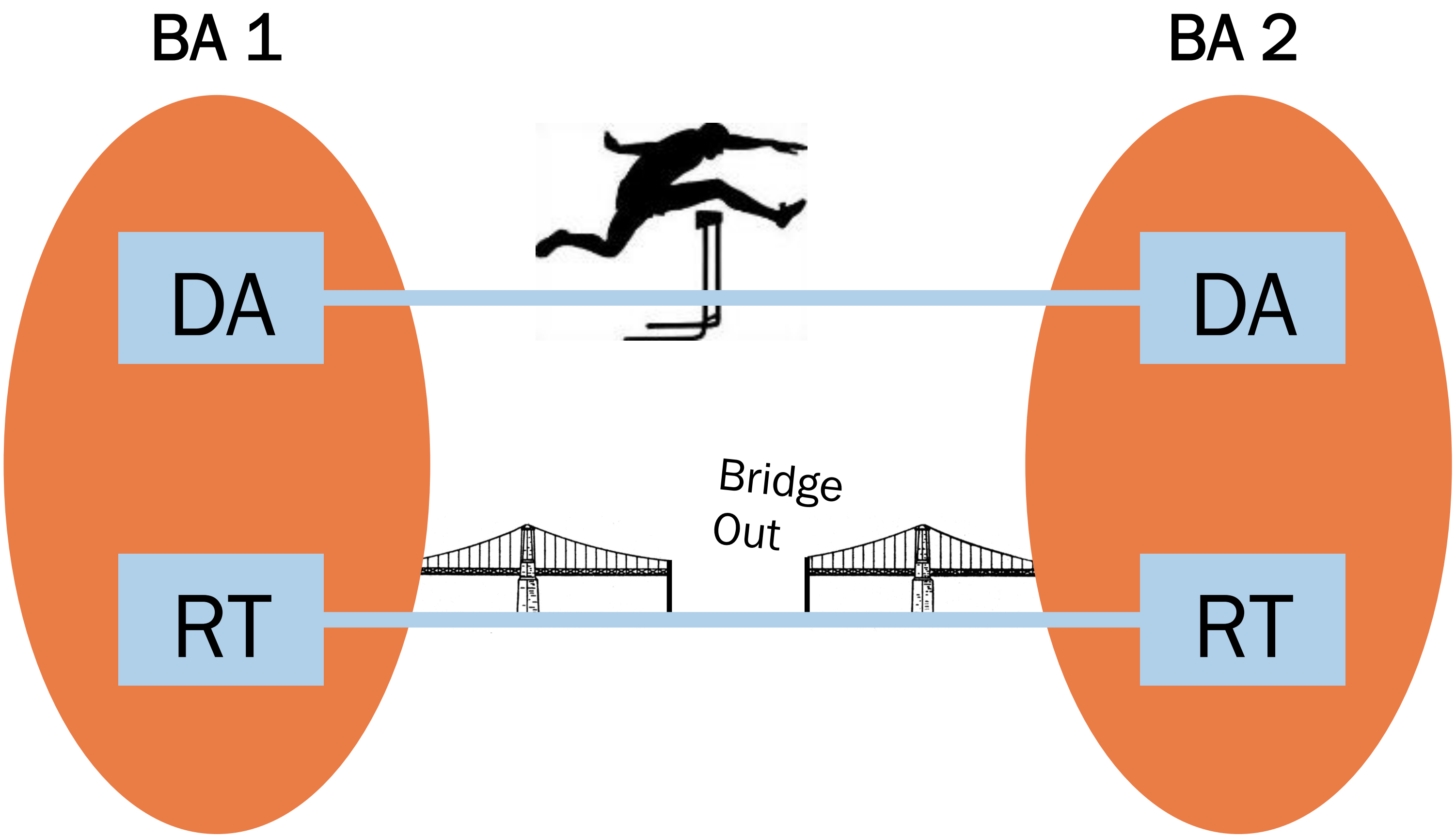
- Definition
  - Within models, a transaction cost that represents barrier to trade between BAs
  - “Economic friction”[1]
- Parameterized to simulate actual amount of trade
  - Not actual price
- Easy to implement in model objective:

$$HR(Trade^{A \to B} + Trade^{B \to A})$$

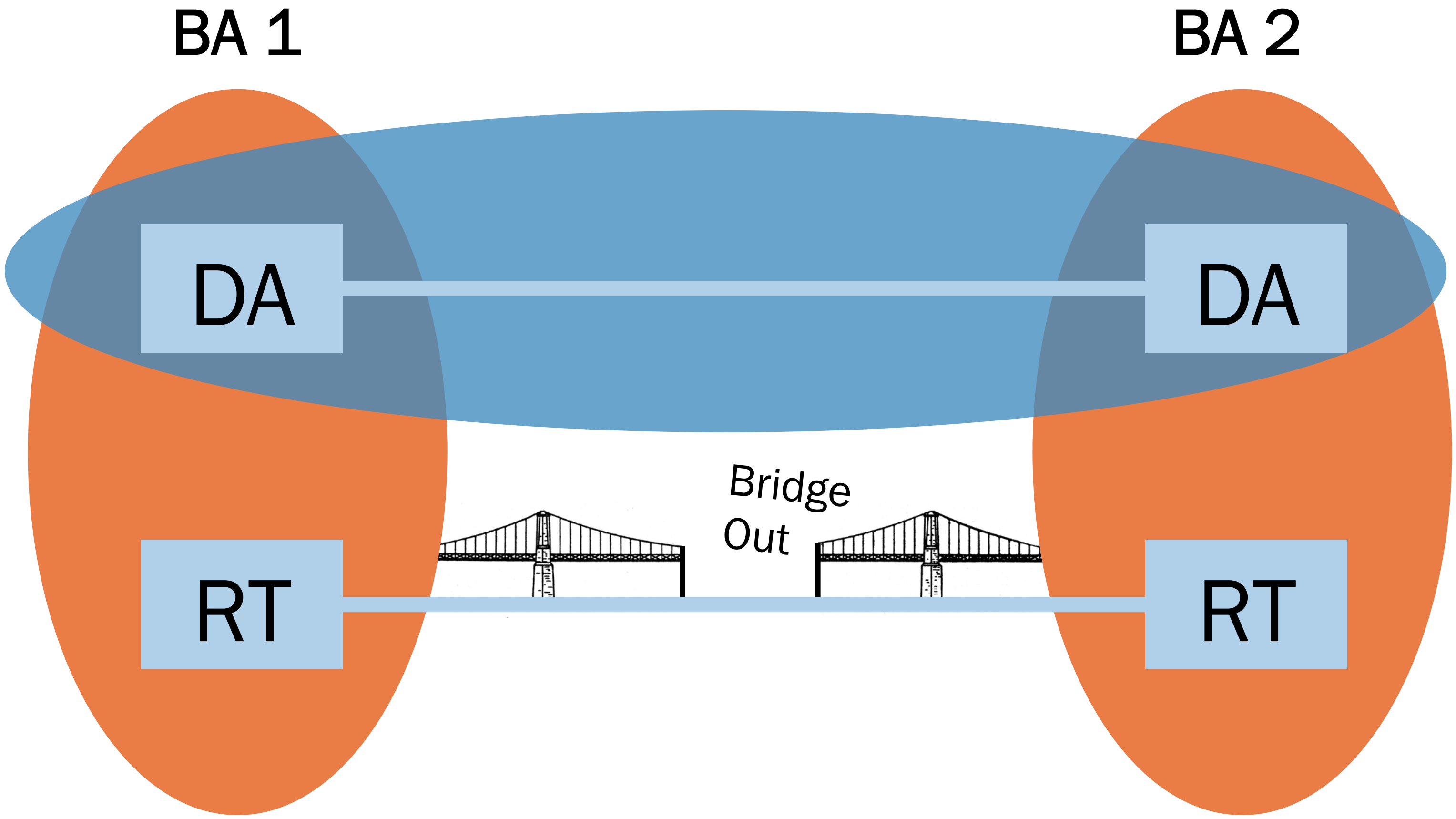
General US Markets



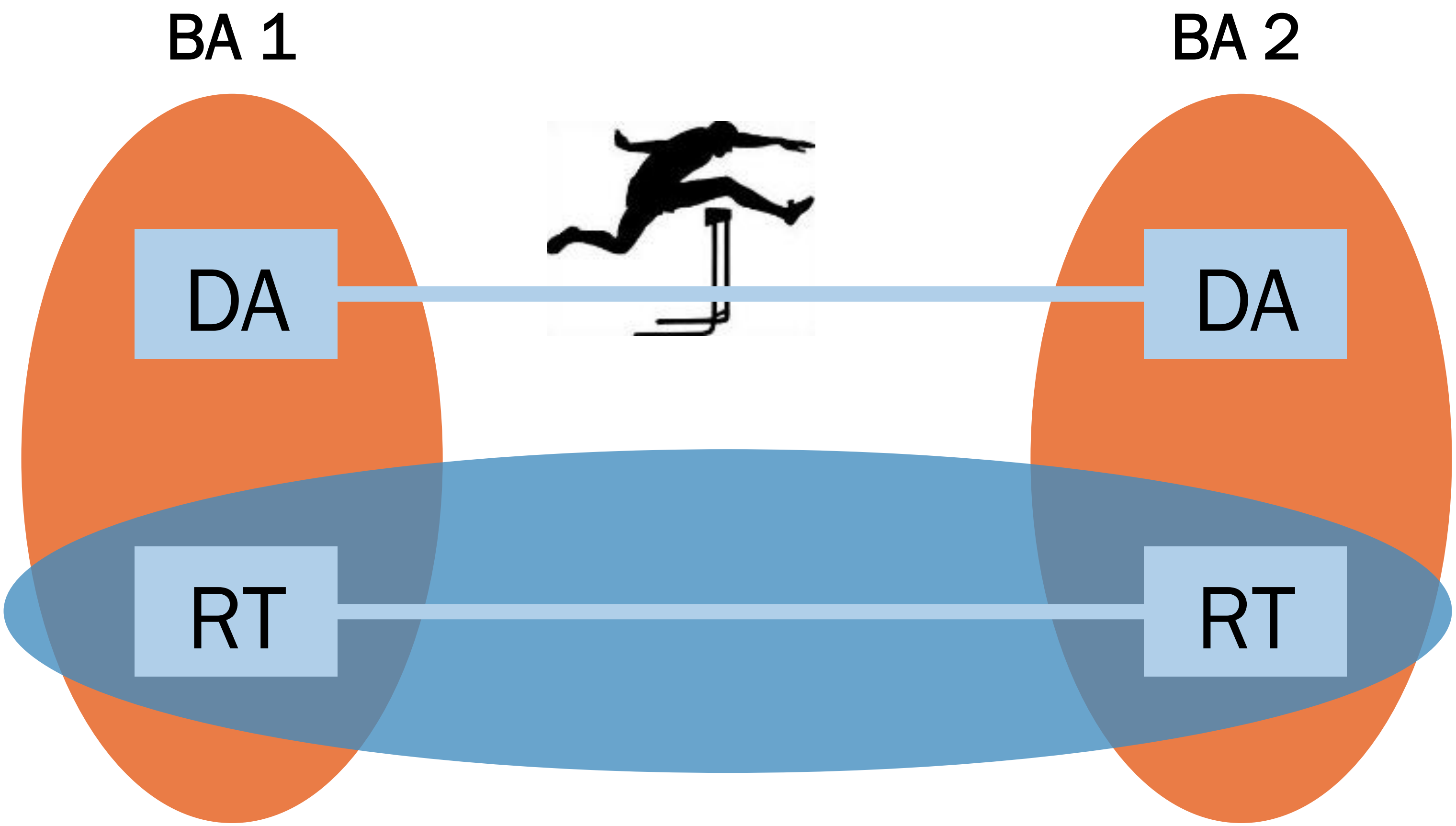
EU Markets (non-market splitting), West Coast



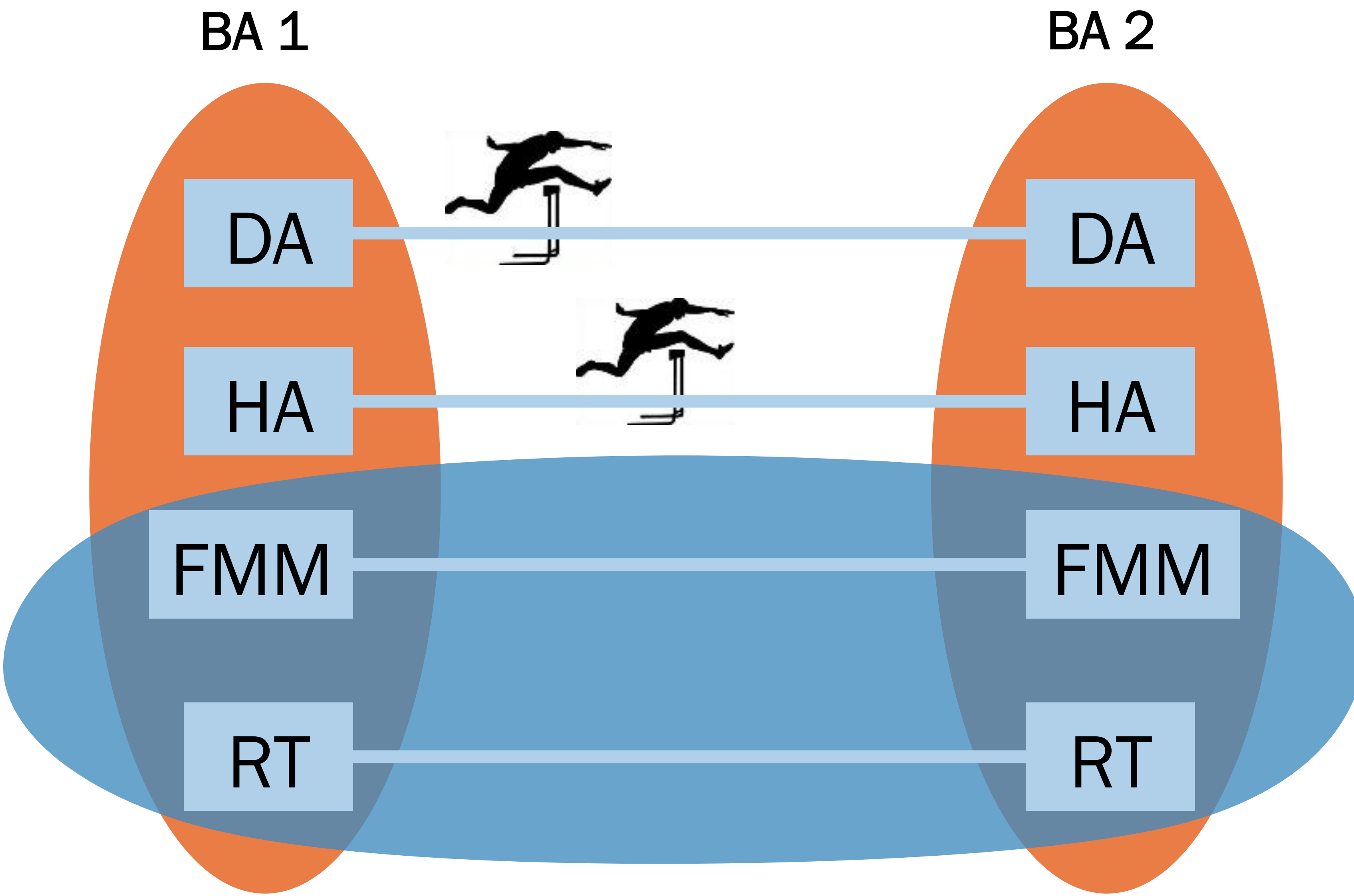
EU Market-Splitting/Coupling



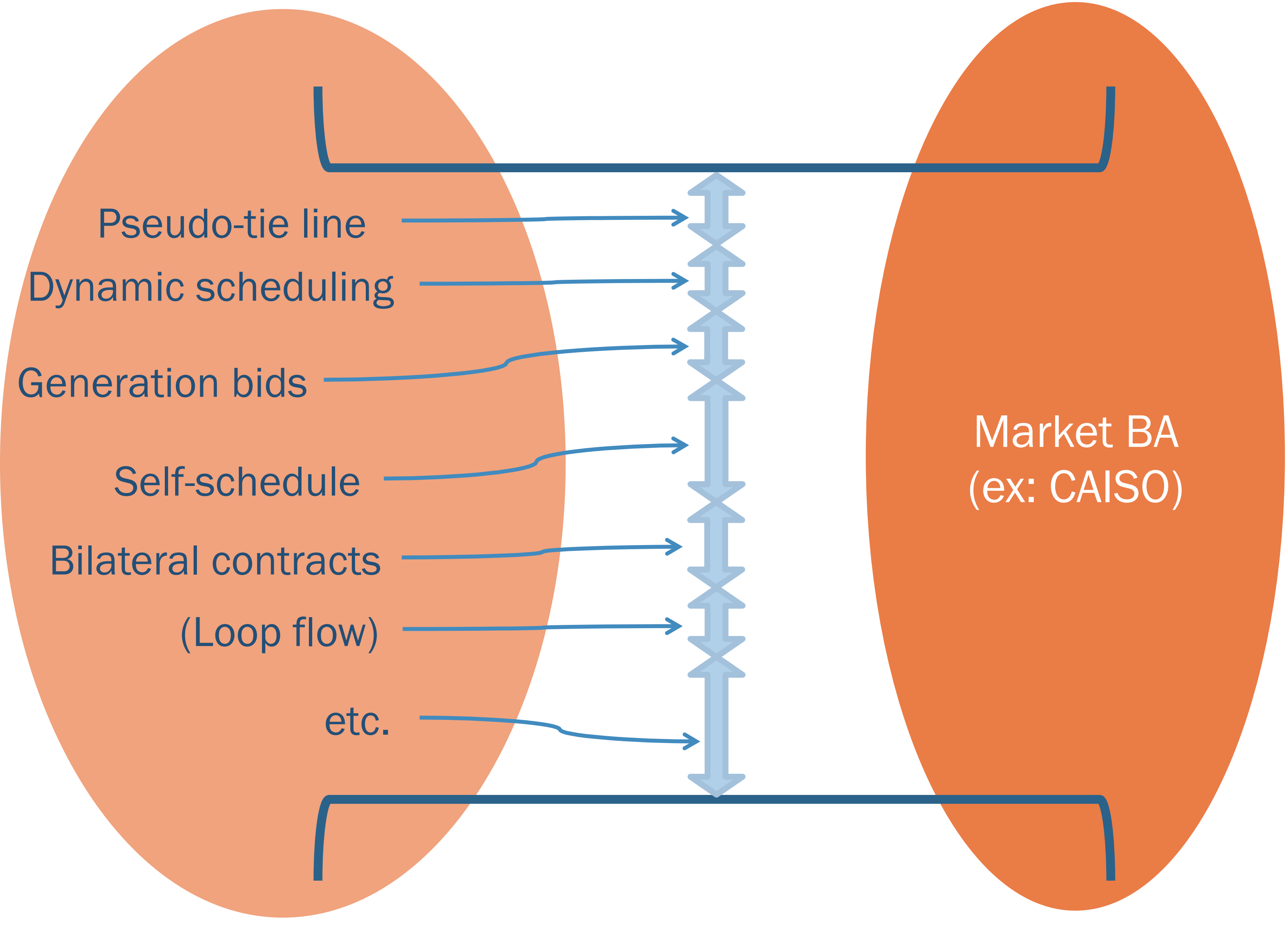
CAISO – PacifiCorp – Nevada Energy Imbalance Market (EIM)



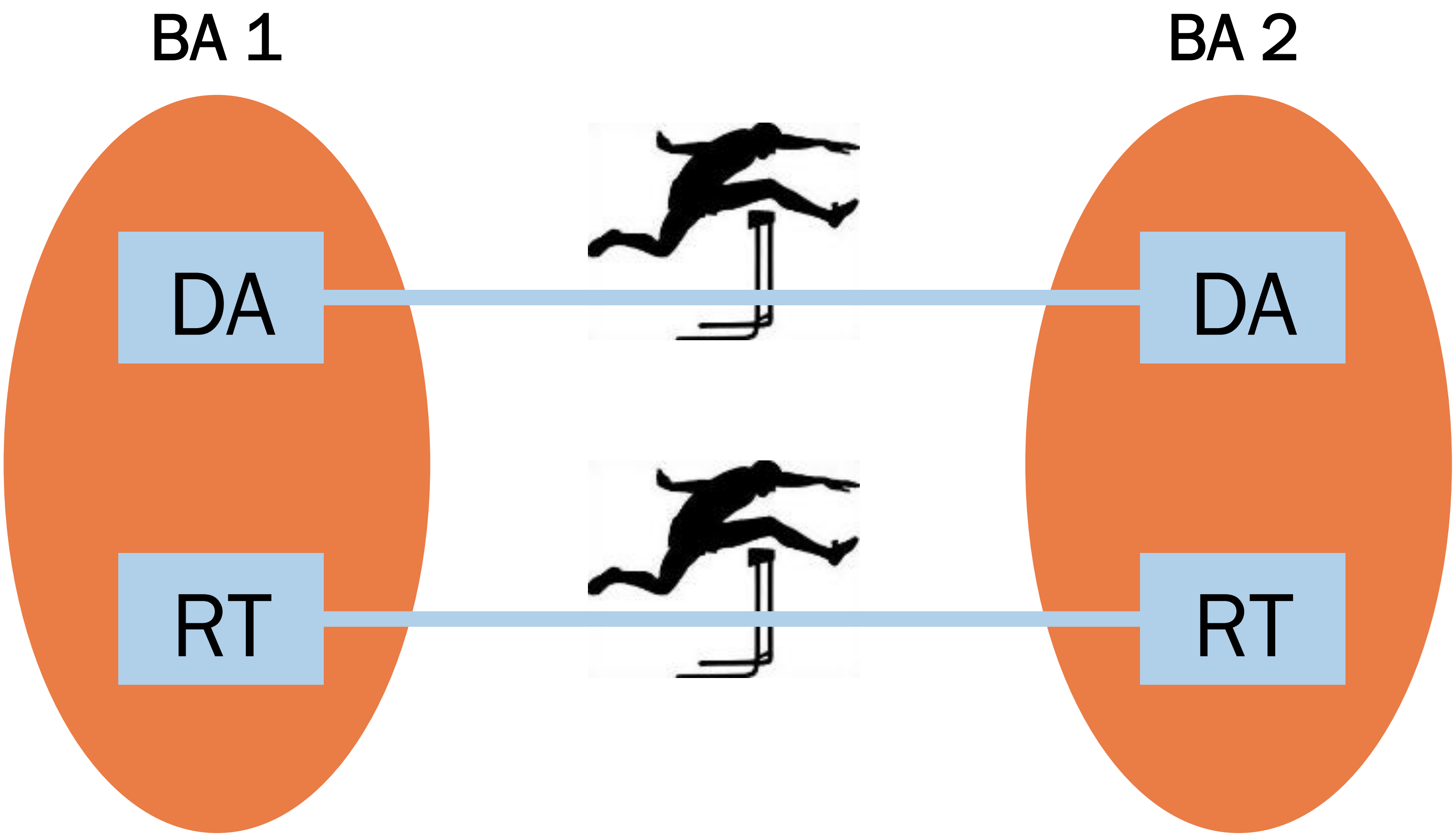
CAISO Energy Imbalance Market Details



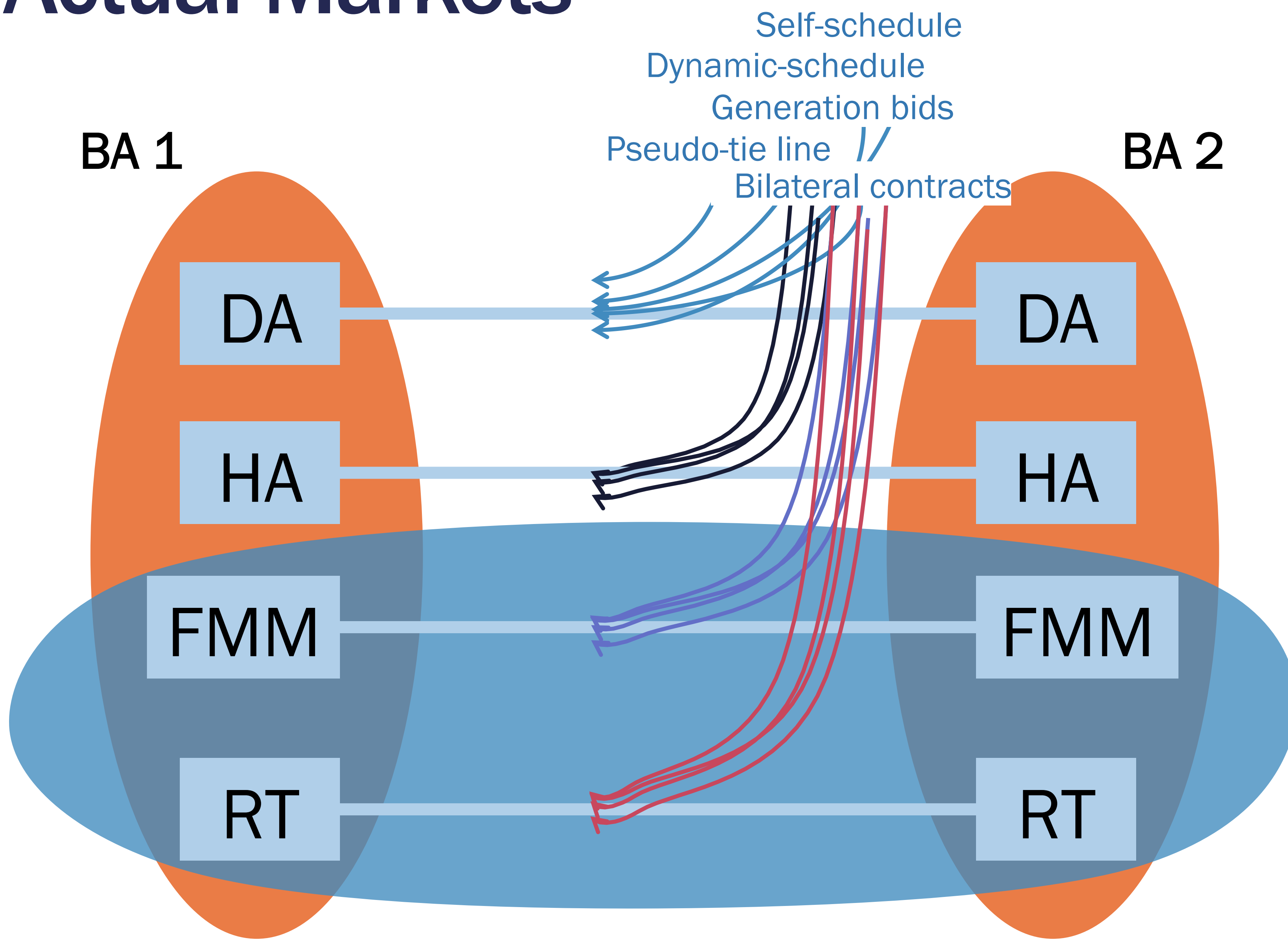
Allocation of BA Interties



General US Markets



Actual Markets



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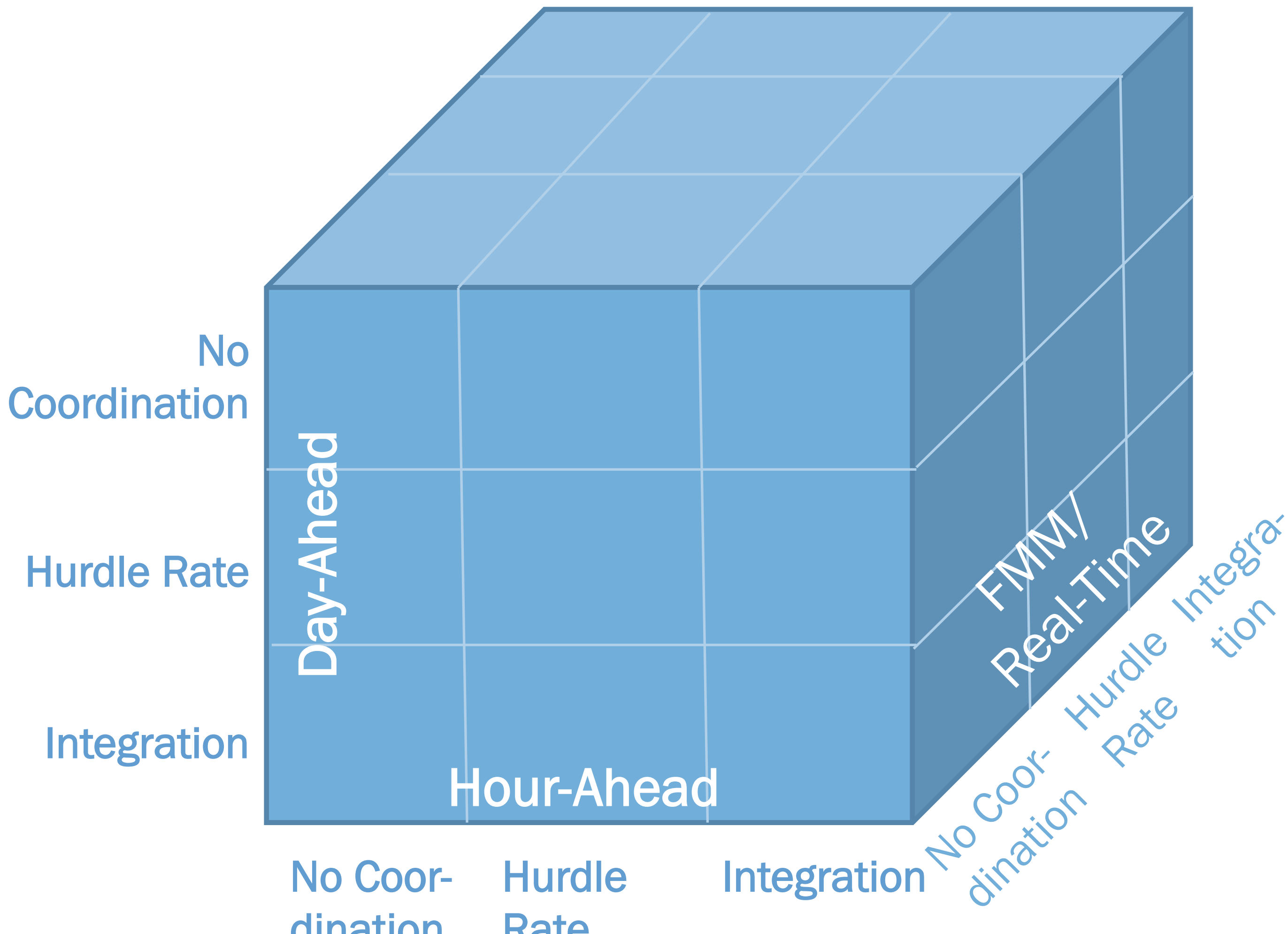
Scenarios

		Real-Time		
		No Coordination	Hurdle Rate	Full Integration
Day-Ahead	No Coordination			
	Hurdle Rate	Old WECC, EU non-market splitting	Regional authorities	CAISO
	Full Integration	EU market splitting/coupling (Nordpool, APX)		Consolidation Single RTO

Scenarios


No Coordination
Hurdle Rate
Integration
Day-Ahead
Hour-Ahead
FMM/ Real-Time
No Coor-dination
Hurdle Rate
Integration
No Coor-dination
Hurdle Rate
Integra-tion

Model

- Types of models
  - *Day-ahead scheduling: unit commitment*
    - Commits generation units for the next day
    - MILP, binary decisions represent commitment
  - *Real-time model*
    - Optimizes (least cost) power flow
  - Both models:
    - Subject to transmission & generation constraints (KCL, KVL, capacity)
    - Options to curtail wind and shed load

Model: Integrated Market

Day-Ahead

$$\min \sum_{\forall t} \sum_{\forall g} c_g P_{g,t} + c_g^{SU} v_{g,t} + c_g^{NL} u_{g,t}$$

Subject to:

Line limits, transmission constraints (BΘ),
capacity limits, ramp rates, minimum up & down times,
spin & non-spin reserve requirements

Real-Time

$$\min \sum_{\forall t} \sum_{\forall g} c_g P_{g,t}$$

Subject to:

Line limits, transmission constraints (BΘ), capacity limits, ramp rates, spin reserve requirements

Model: Hurdle Rate

Day-Ahead

$$\min \sum_{\forall t} \sum_{\forall g} \left(c_g P_{g,t} + c_g^{SU} v_{g,t} + c_g^{NL} u_{g,t} \right) + HR(S_t^{AB} + S_t^{BA})$$

Subject to

$$S_t^{AB} - S_t^{BA} = \sum_{\forall k \in IT} P_{k,t}^{line} \quad \forall t$$

Line limits, transmission constraints (BΘ),
capacity limits, ramp rates, minimum up & down times,
spin & non-spin reserve requirements

Real-Time

$$\min \sum_{\forall t} \sum_{\forall g} \left(c_g P_{g,t} \right) + HR(S_t^{AB} + S_t^{BA})$$

Model: No Coordination

Day-Ahead

$$\min \sum_{\forall t} \sum_{\forall g} c_g P_{g,t} + c_g^{SU} v_{g,t} + c_g^{NL} u_{g,t}$$

Subject to

$$\sum_{\forall k \in IT} P_{k,t}^{line} = 0 \quad \forall t$$

Line limits, transmission constraints (BΘ), capacity limits, ramp rates, minimum up & down times, *separate* spin & non-spin reserve requirements

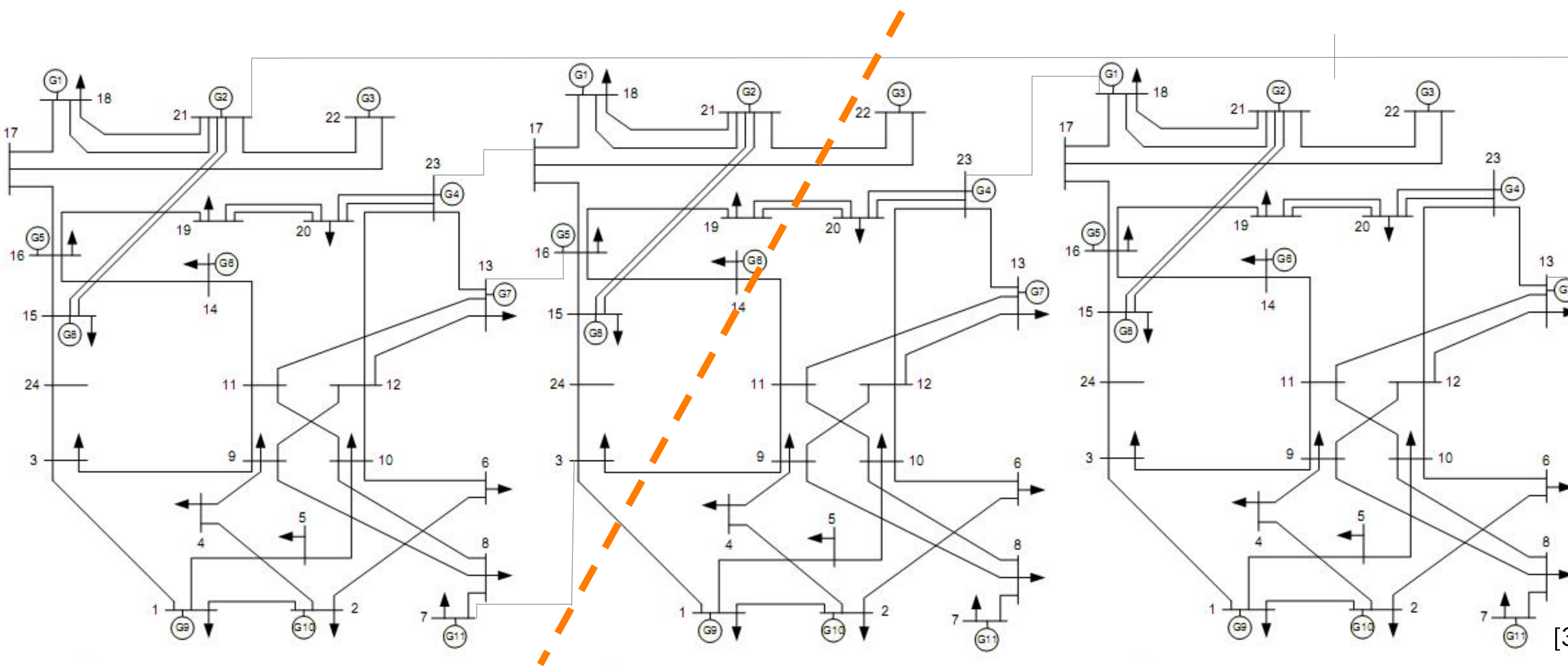
Real-Time

$$\min \sum_{\forall t} \sum_{\forall g} c_g P_{g,t}$$

System Topography

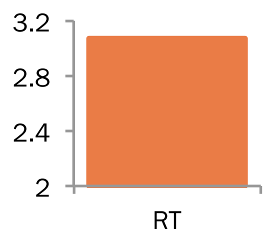
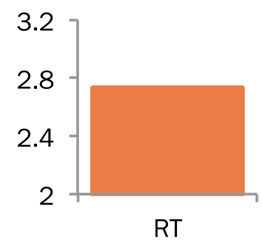
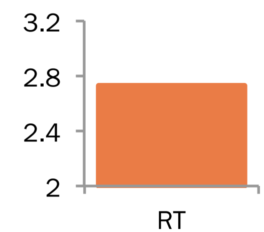
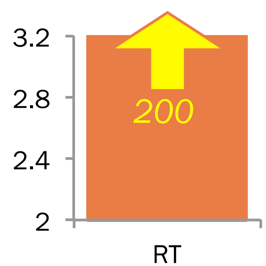
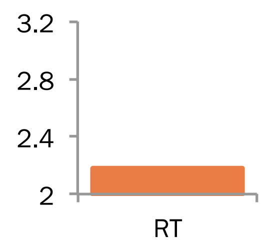
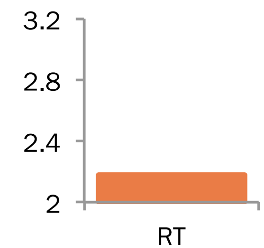
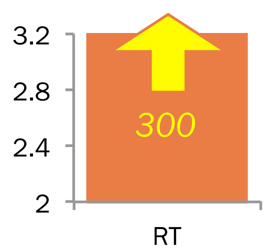
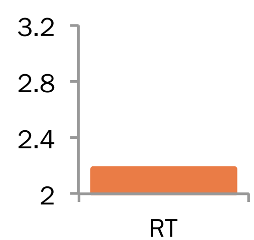
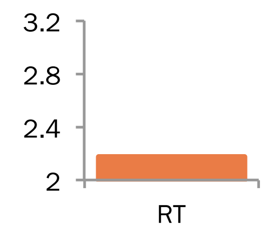
- Reliability Test System 1996
- 3 Zone (99 generators, 73 buses)
- 24 hours

- Each BA is similar in size
  - # generators
  - Type of generation
  - Wind capacity

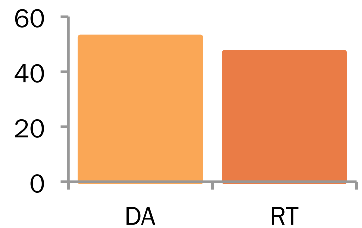
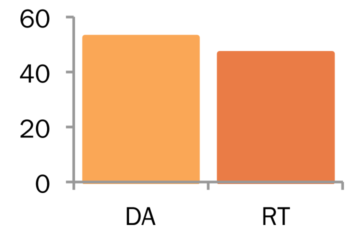
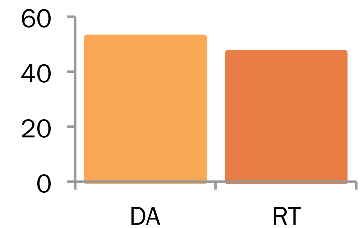
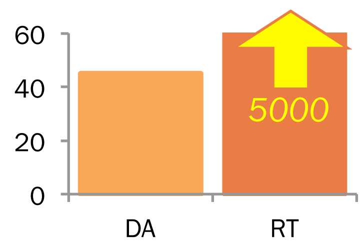
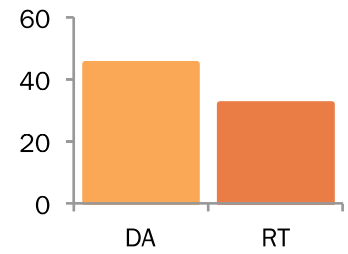
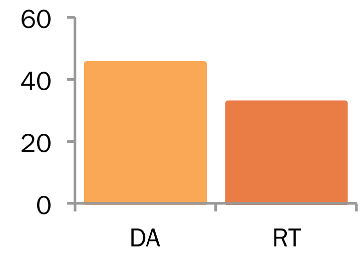
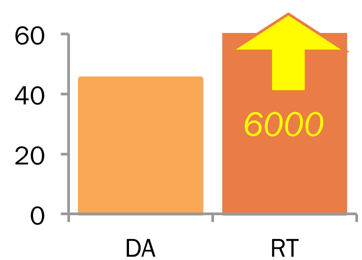
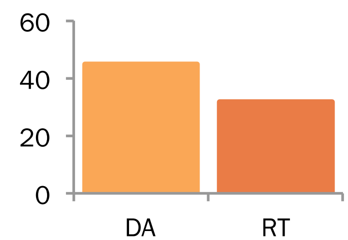
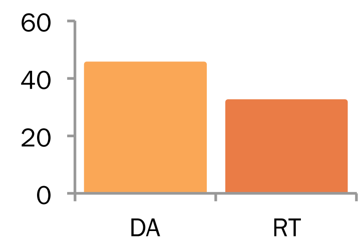


[3]

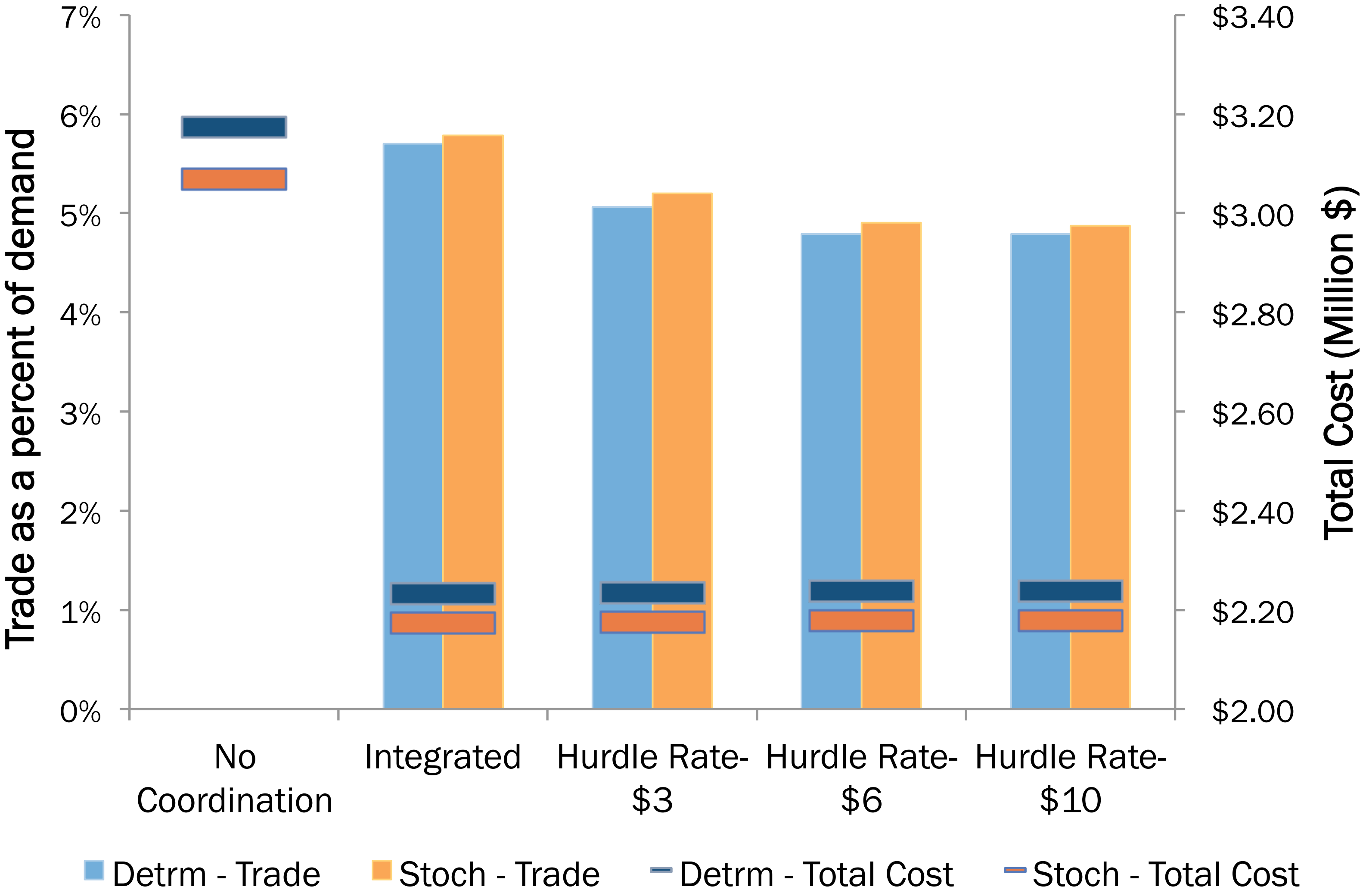
Results – Real Time Costs

Total Cost (Millions $)		RT		
		No Coordination	Hurdle Rate	Full Integration
DA	No Coordination			
	Hurdle Rate			
	Full Integration			

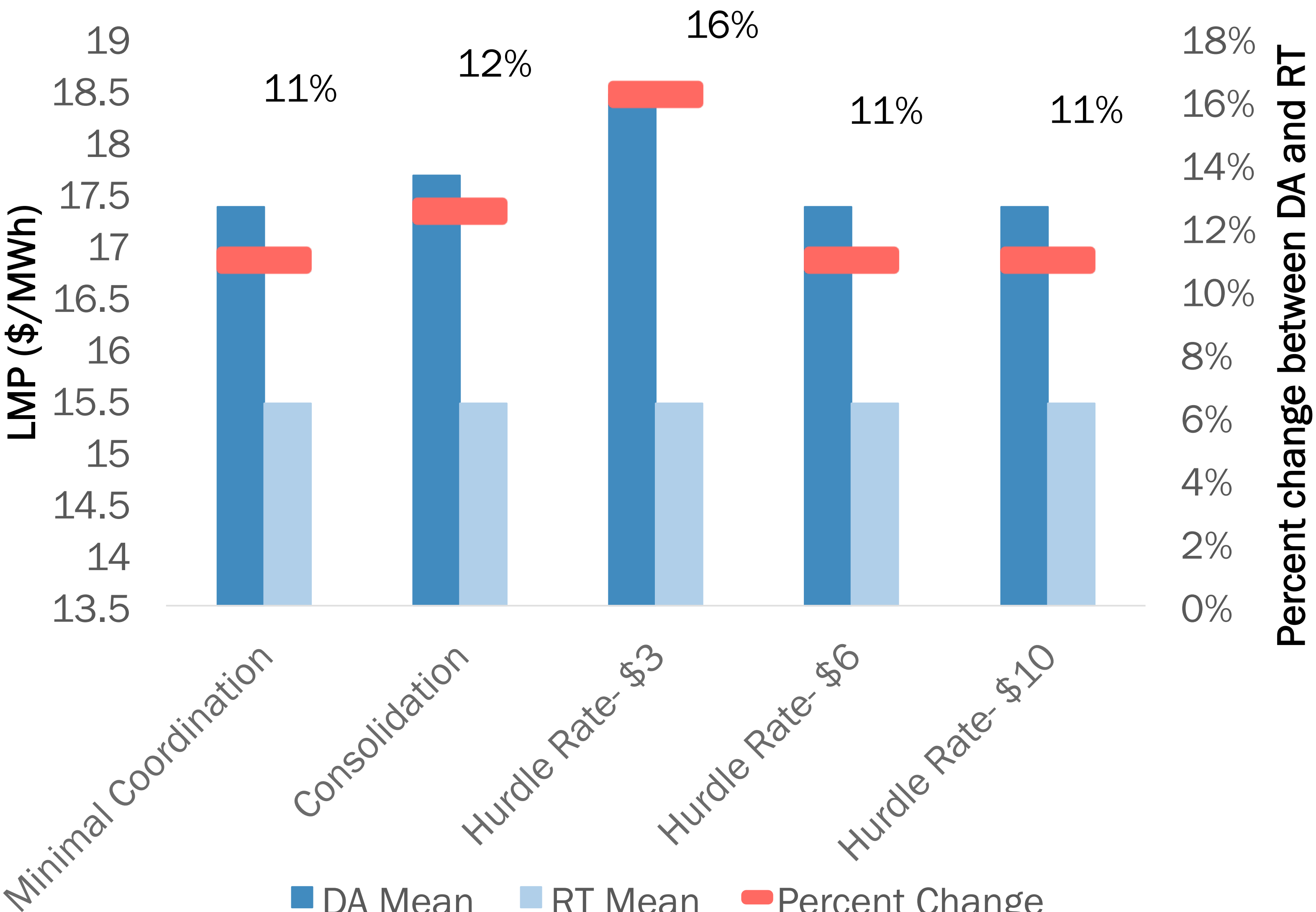
Results – Prices

Average LMP ($/MWh)		RT: No Coordination	RT: Hurdle Rate	RT: Integrated Market
DA	No Coordination			
	Hurdle Rate			
	Integrated Market			

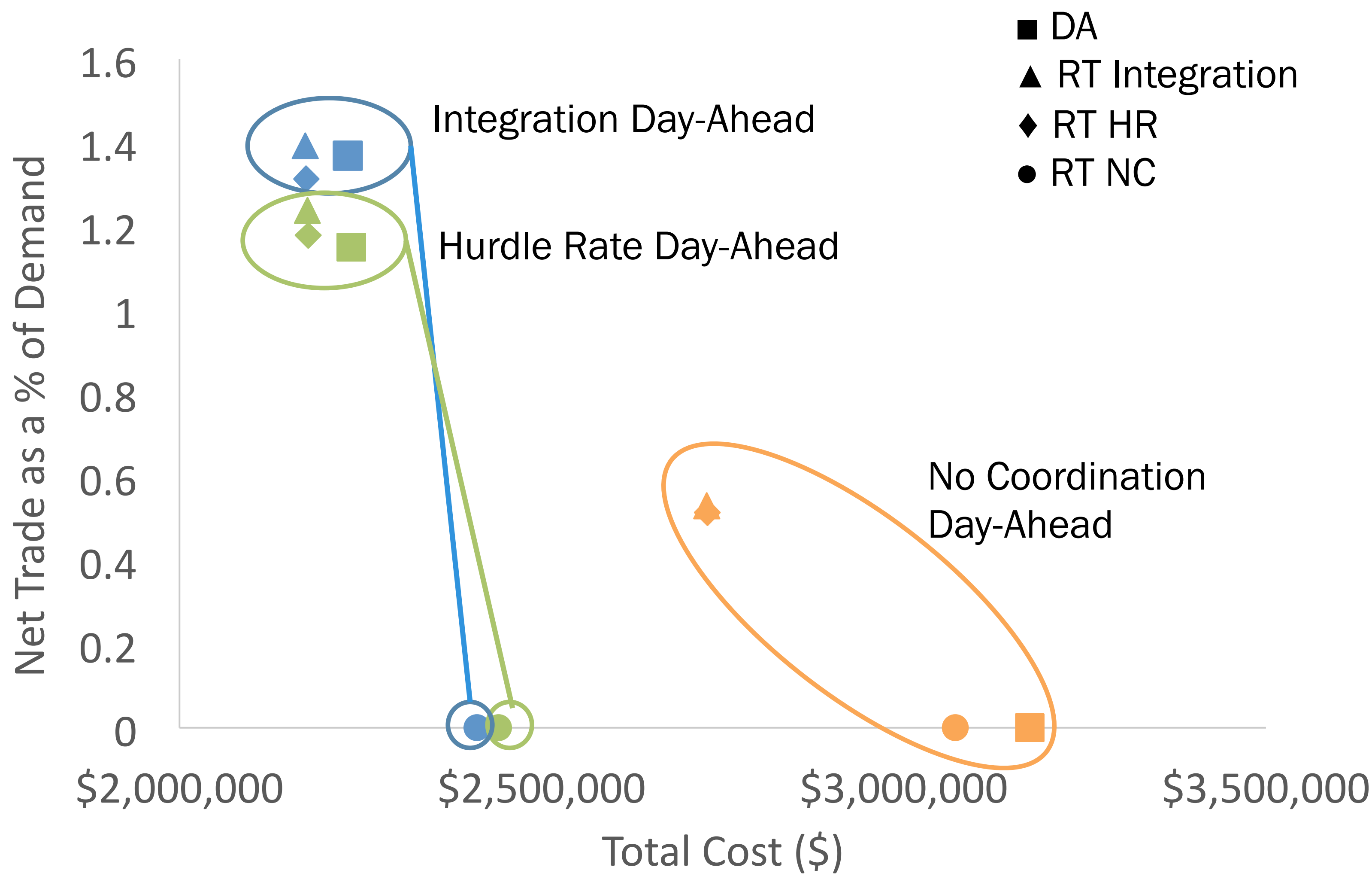
Results - deterministic and stochastic wind scenarios



Price results – single wind forecast



Results – All scenarios



Conclusions

- Integrated markets yield most gains from trade
  - Barriers on interties impede efficient markets
  - Going from no coordination to hurdle rates makes large difference
  - Further lowering hurdle rates most beneficial in DA rather than RT
- Further work needed to determine the simplifying effect of hurdle rates relative to actual barriers
  - Which barriers are most important to address?
  - Who should be responsible for removing inefficiencies?
- When no RT coordination, there might not be enough generation on-line to meet demand
- Average prices more consistent DA vs RT when there is no coordination day-ahead

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Future Work

- Different size BAs, different generation mix
- Modeling specific barriers on the intertie line
  - Self-scheduling
  - Dynamic-scheduling
- COMPETES model – ECN
  - Look at European grid
- Additional balancing areas
- Greatest benefits for renewables

Thank you!

Questions?

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References

- [1] Joseph H. Eto, Douglas R. Hale and Bernard C. Lesieutre, “Toward More Comprehensive Assessments of FERC Electricity Restructuring Policies: A Review of Recent Benefit-Cost Studies of RTOs” *The Electricity Journal*
- [2] Frank Wolack, “The Economics of Self Scheduling,” Presentation available: http://www.caiso.com/Documents/Presentation-Economics-Self-Scheduling-MSCPresentation.pdf
- [3] Jesús María López-Lezama, Mauricio Granada-Echeverri, and Luis A. Gallego-Pareja, “A combined pool/bilateral dispatch model for electricity markets with security constraints” *Ingeniería y Ciencia*, June 2011.