

Game-Based Electricity Markets Training

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California ISO
250 Outcropping Way, Folsom, California
May 9-10, 2024

² Workshop Agenda

Day 1

- Uniform-price auctions and unilateral market power
- Pay-as-bid auctions (why aren't they used?)
- Transmission congestion
- How forward contracts reduce generators' incentives to exercise unilateral market power

Day 2

- Operation of day-ahead markets (with start-up costs example)
- Variable renewable energy and day-ahead markets

Fundamentals of Wholesale Electricity Markets

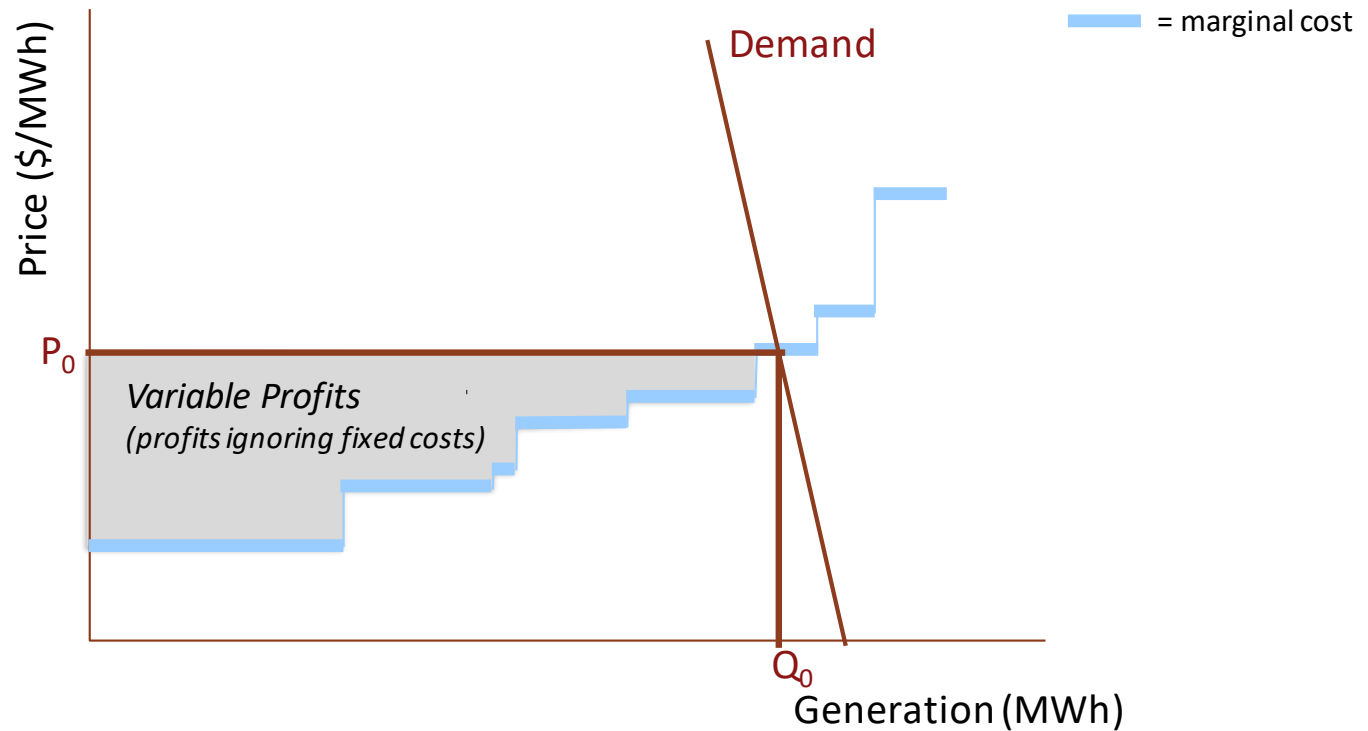
Sample Power Plant Characteristics

Sample Unit Types	Capacity (MW)	Marginal cost, no carbon price (\$/MWh)	Fixed cost (\$/hr)	Emissions rate (tonnes CO ₂ /MWh)
Coal	2000	20	50,000	1.0
Gas CCGT	1000	45	10,000	0.5
Gas CT	500	90	1,500	1.0

*Values are for illustrative purposes only and do not necessarily reflect the performance of real power plants

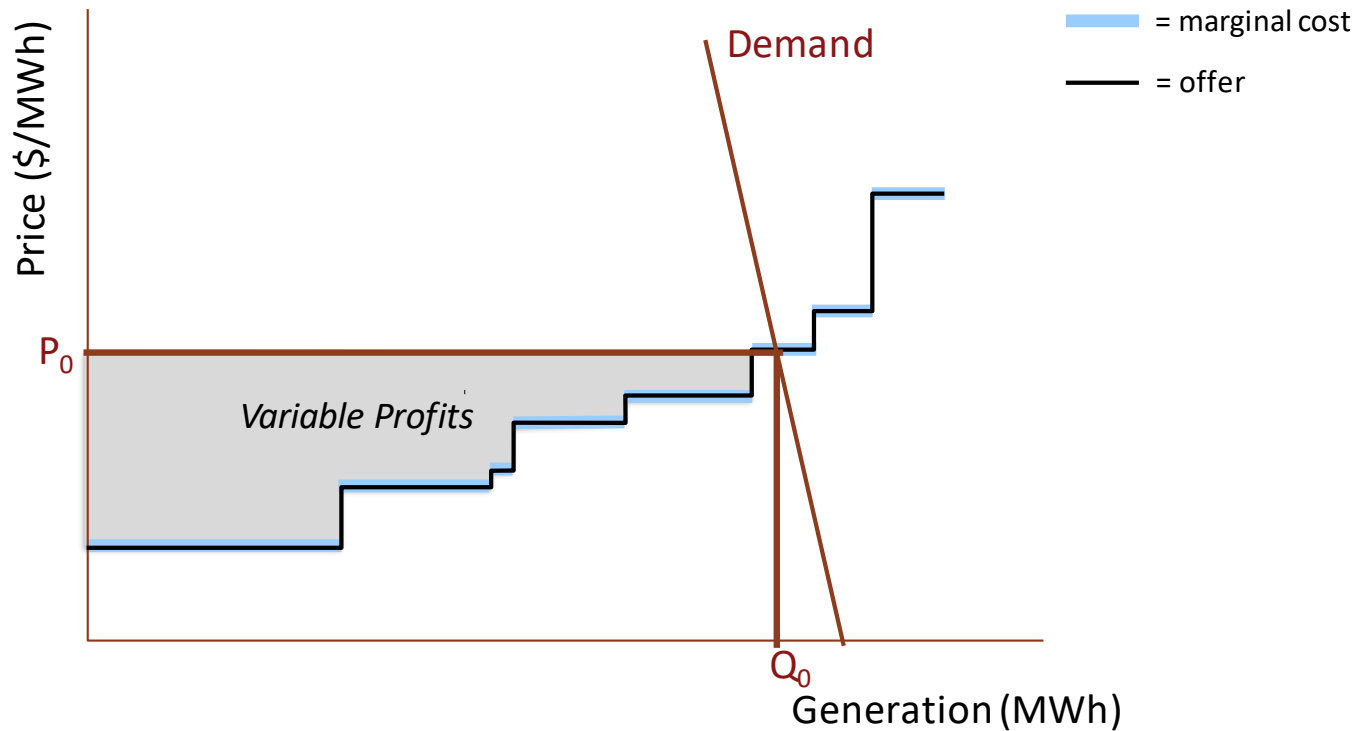
- Capacity – How much electrical power (MW) can you generate
- Marginal cost – What is the incremental cost of *running* your power plant, in \$ per unit of electrical energy generated (MWh)
- Fixed cost – How much does it cost you just to “*sit around*” in \$ per hour (i.e. you pay this whether you run or not).
- Emissions rate – How much CO₂ do you emit (tonnes) per unit of electrical energy generated (MWh)?
- Startup cost – *We won't consider this yet in our games, but real power plants have a cost associated with starting up*

Cost-Based, Uniform-Price Market



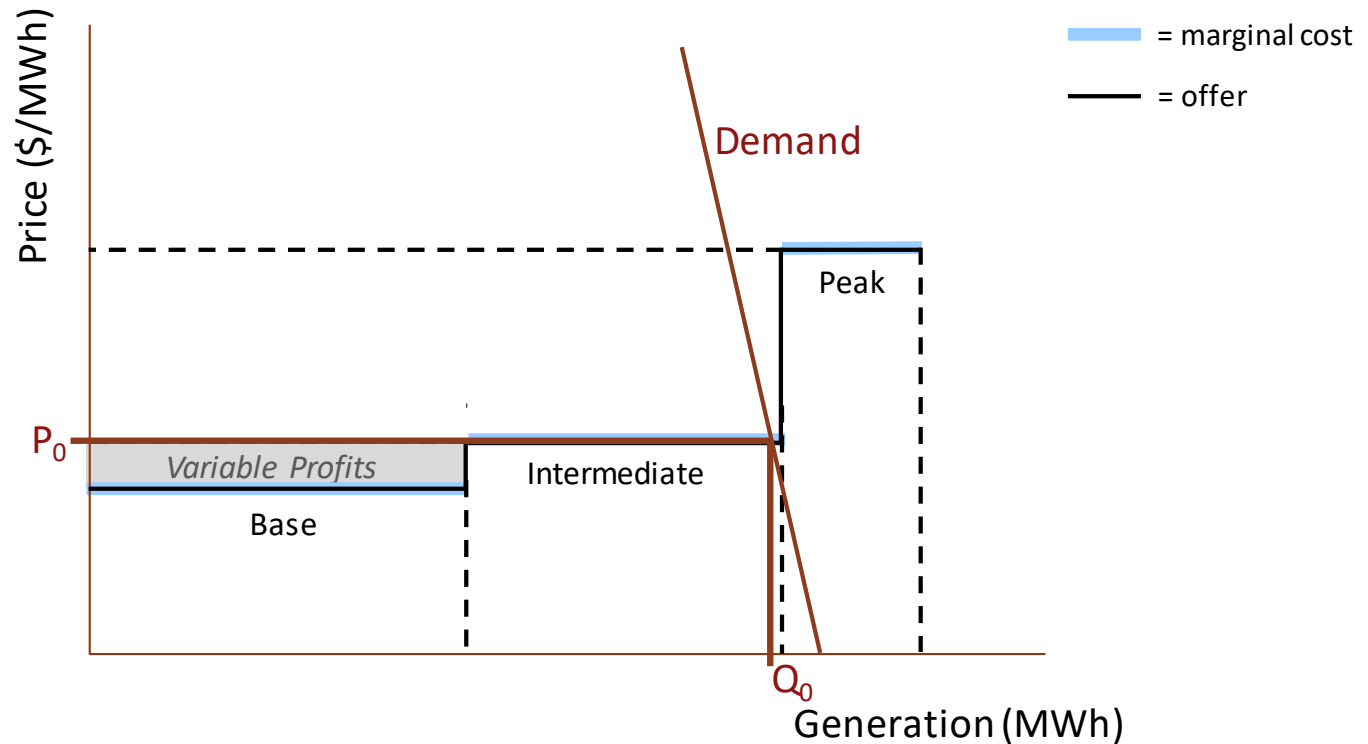
- In a *cost-based market*, the Independent System Operator (ISO) orders power plants from lowest to highest marginal cost and crosses this “merit order” with the expected demand curve to determine the market-clearing price (P_0) and the resulting output (Q_0)
- In a *uniform-price auction*, all plants that run (i.e. that are to the left of where the demand curve crosses) are paid the market-clearing price P_0

Offer-Based, Uniform-Price Market: Generators Bid Marginal Cost



- In an *offer-based market*, generating companies (“gencos”) offer in each of their power plants at any price up to the offer cap. As before, the ISO orders these offers from lowest to highest and crosses with the demand curve.
- Should power plant fixed costs factor into offer strategy?
- What should you offer if you cannot influence the price?

Offer-Based, Uniform-Price Market: Potential for Unilateral Market Power



- Should you ever offer below marginal cost?
- Should you ever offer above marginal cost?

Let's try it => http://energymarketgame.org/apps/unilateral_market_power/

Exercise of Unilateral Market Power

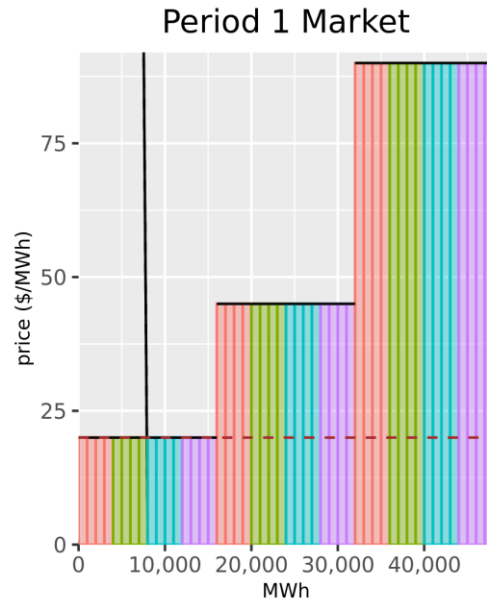
Reasons this is a particular challenge for electricity markets:

- Limited ability to store electricity
- Supply must meet demand at every instant in every location
- Capacity constraints

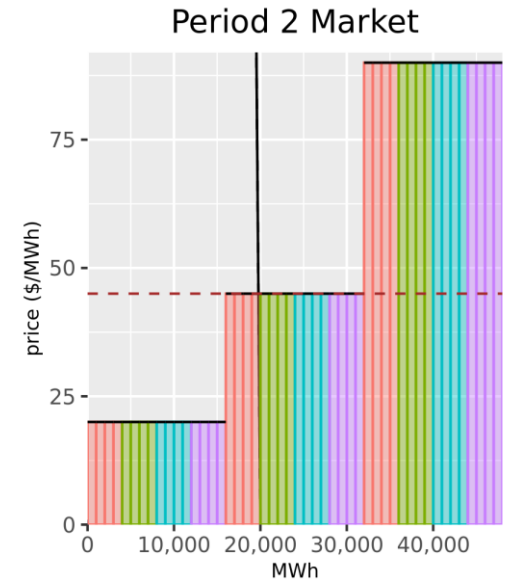
Conditions making it easier to exercise unilateral market power:

- Limited demand response (inelastic demand curve)
- *Generators do not have fixed-price forward contract obligations* (e.g. California pre-crisis)

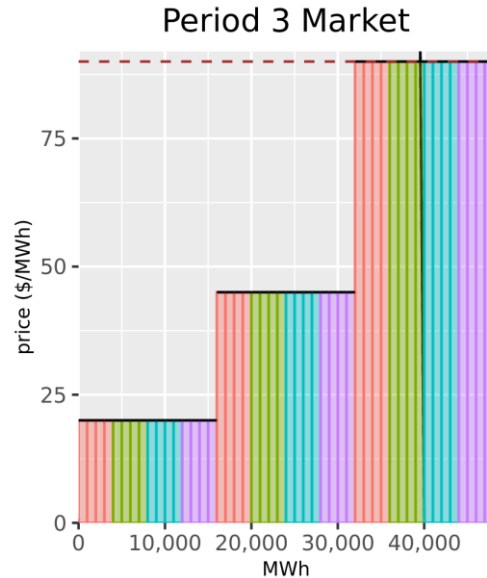
Four-period game



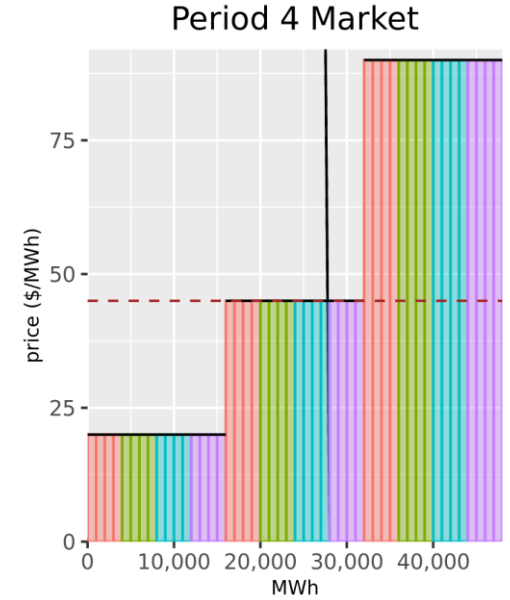
Market price: \$20.00
 Wind: 100% of expected
 Note: black line shows marginal cost



Market price: \$45.00
 Wind: 100% of expected
 Solar: 100% of expected
 Note: black line shows marginal cost



Market price: \$90.00
 Wind: 100% of expected
 Solar: 100% of expected
 Note: black line shows marginal cost



Market price: \$45.00
 Wind: 100% of expected
 Note: black line shows marginal cost

Hour	Approx. Demand (MWh)	Expected Price (\$/MWh)
4am	8000	20
10am	20000	45
4pm	40000	90
10pm	28000	45

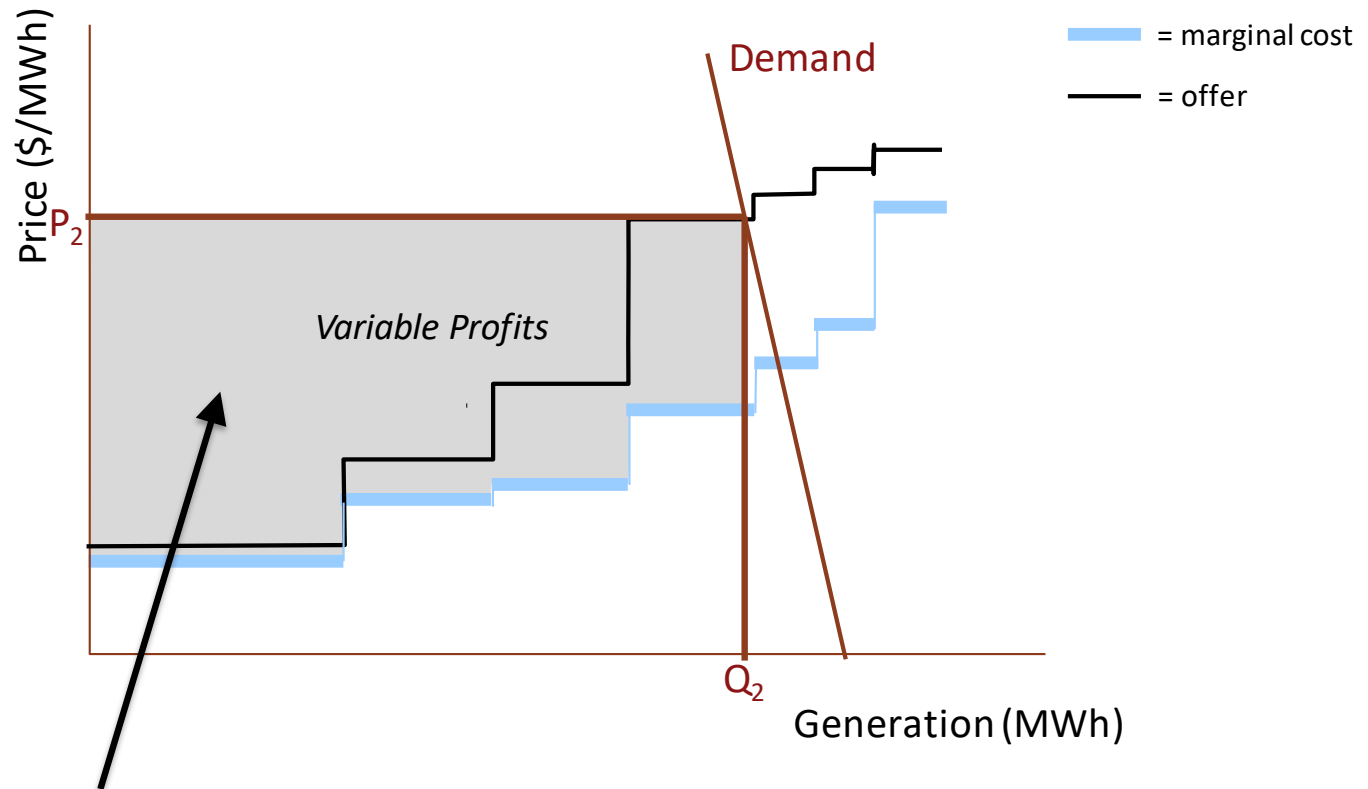
Game #1

Basics of Market Operation

- Uniform-Price Auction
- Exercise of Unilateral Market Power

Uniform Price vs. Pay-As-Bid Auction

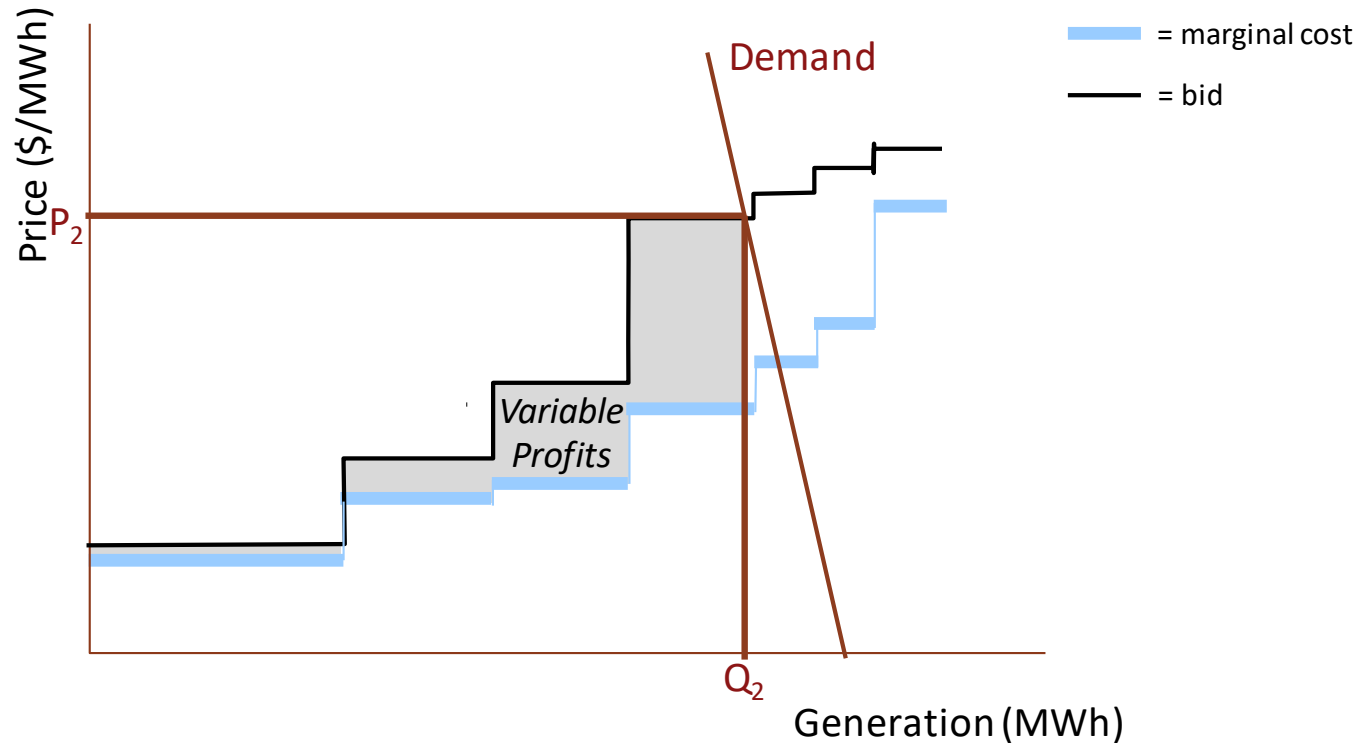
Offer-Based, Uniform-Price: Generators Offer Higher Than Marginal Cost



We know these generators are being paid much more than their marginal costs. Can we save ratepayers money by only paying what they offer (“bid”) to the generators that end up running? (Politicians will, not unreasonably, ask this question!)

Offer-Based, *Pay-As-Bid*:

Generators Offer Higher Than Marginal Cost



- Will a Pay-As-Bid Auction save money for ratepayers?
- How does the Pay-As-Bid Auction change genco bidding strategy? (Does it still make sense for gencos to offer marginal cost? Why or why not?)

Game #2

Pay-As-Bid Auction

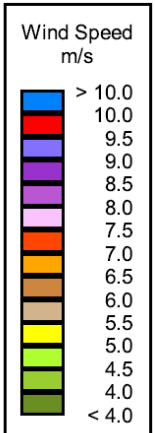
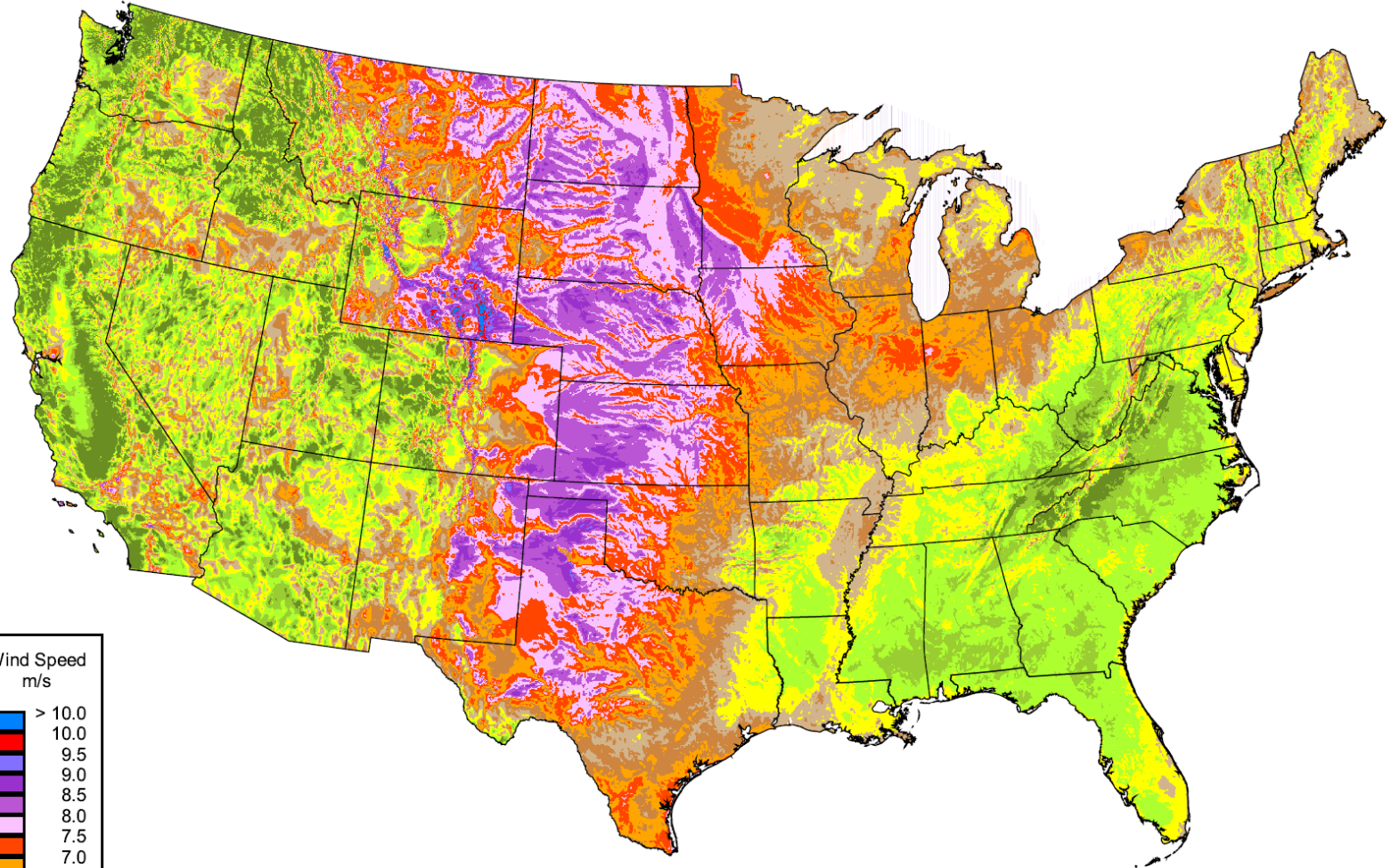
Congestion (i.e. transmission constraints)

Transmission constraints

- We have been assuming a “copper plate model” – i.e. electricity generated anywhere in our market can flow to consumers anywhere in our market
- In reality, transmission constraints exist: if we try to send too much electricity through a transmission line, we will fry the wire. The ISO needs to make sure this doesn't happen.
- Transmission constraints crucially affect:
 - Market competitiveness (i.e. how many gencos can serve demand at a given location at a given point in time)
 - Our ability to access cheap renewable energy at locations distant from consumer demand. (Often, people live far from the best renewable resources!)

Wind Resources in US

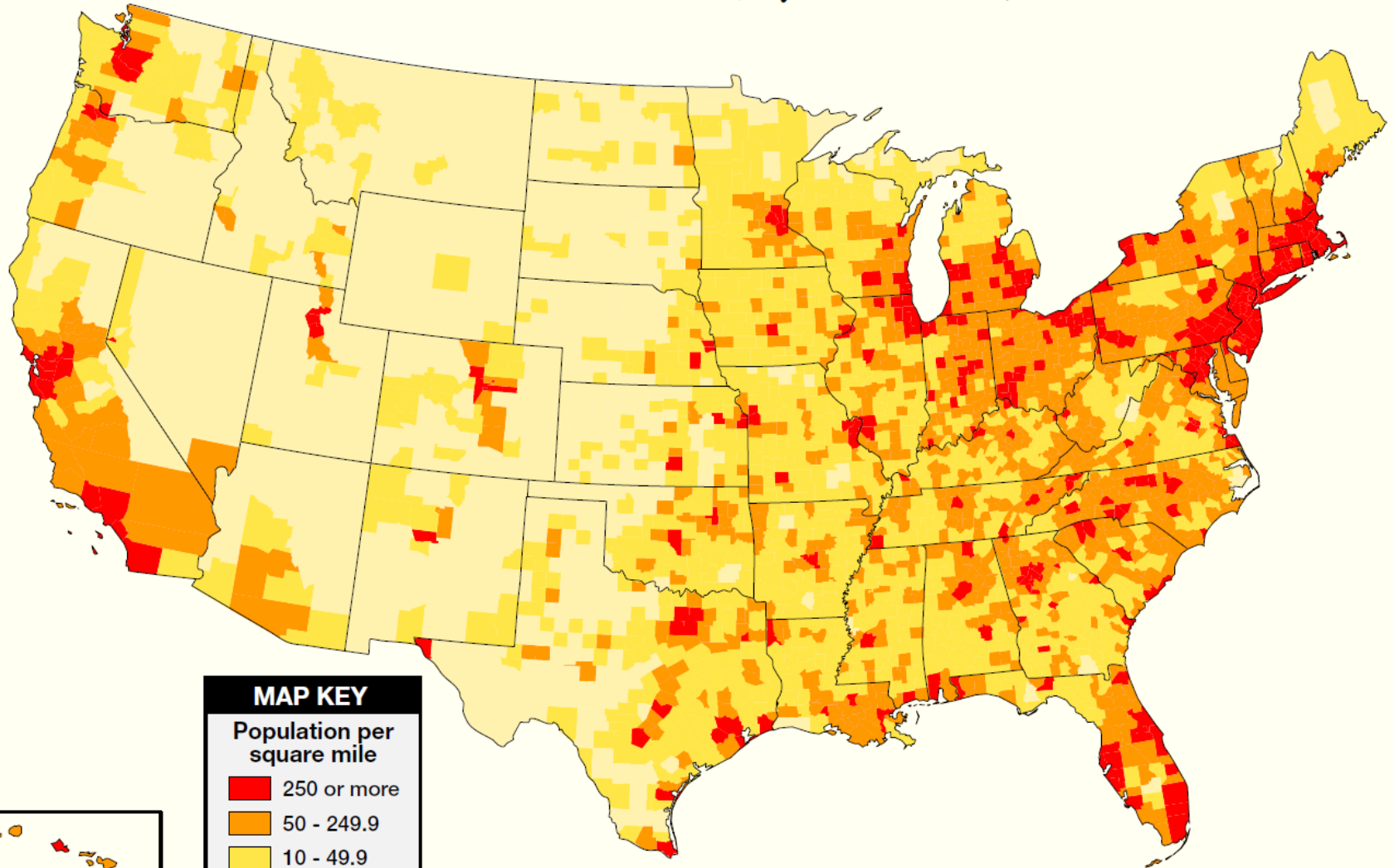
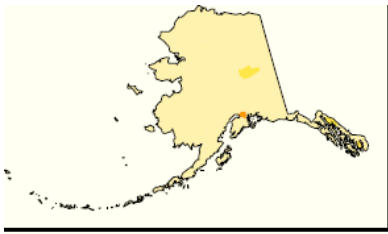
United States - Annual Average Wind Speed at 80 m



Source: Wind resource estimates developed by AWS Truewind, LLC for windNavigator®. Web: <http://navigator.awstruewind.com> | www.awstruewind.com. Spatial resolution of wind resource data: 2.5 km. Projection: Albers Equal Area WGS84.



U.S. Population Density (By Counties)



MAP KEY

Population per
square mile

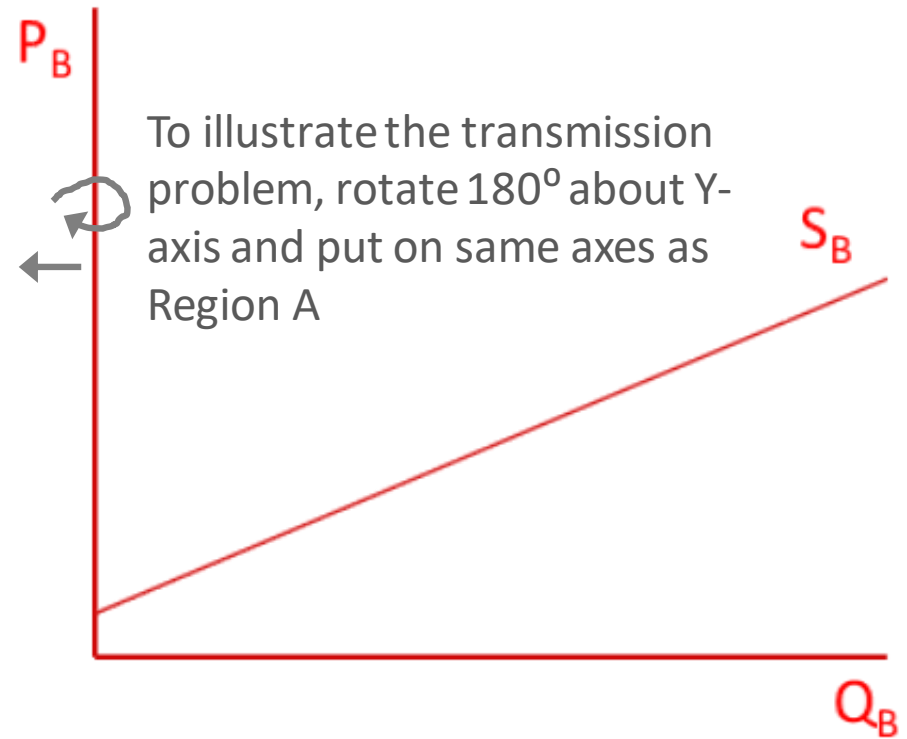
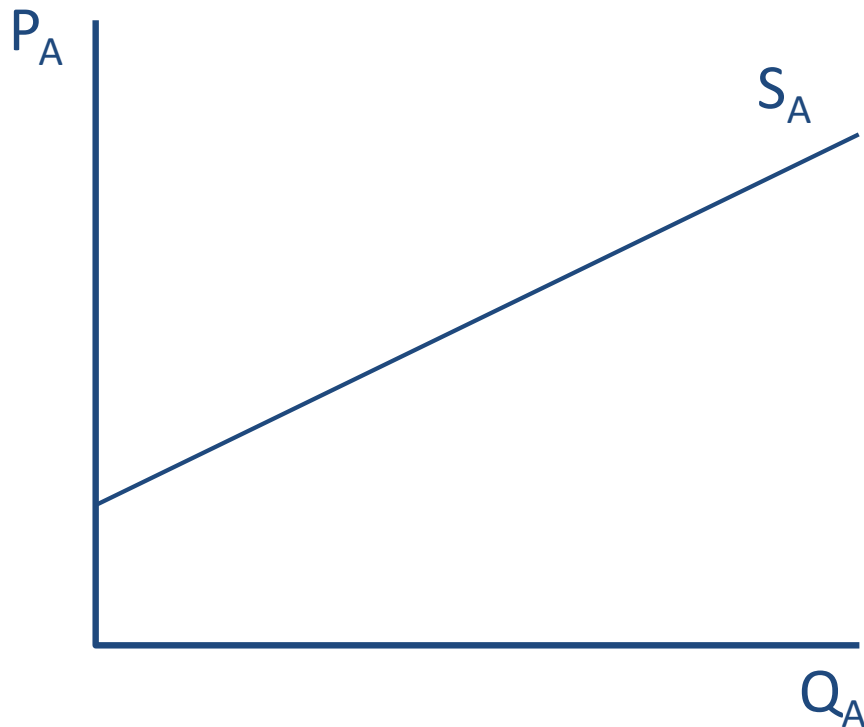
- 250 or more
- 50 - 249.9
- 10 - 49.9
- less than 10



Transmission Constraints

- Consider two regions: A (supply and demand), B (supply)

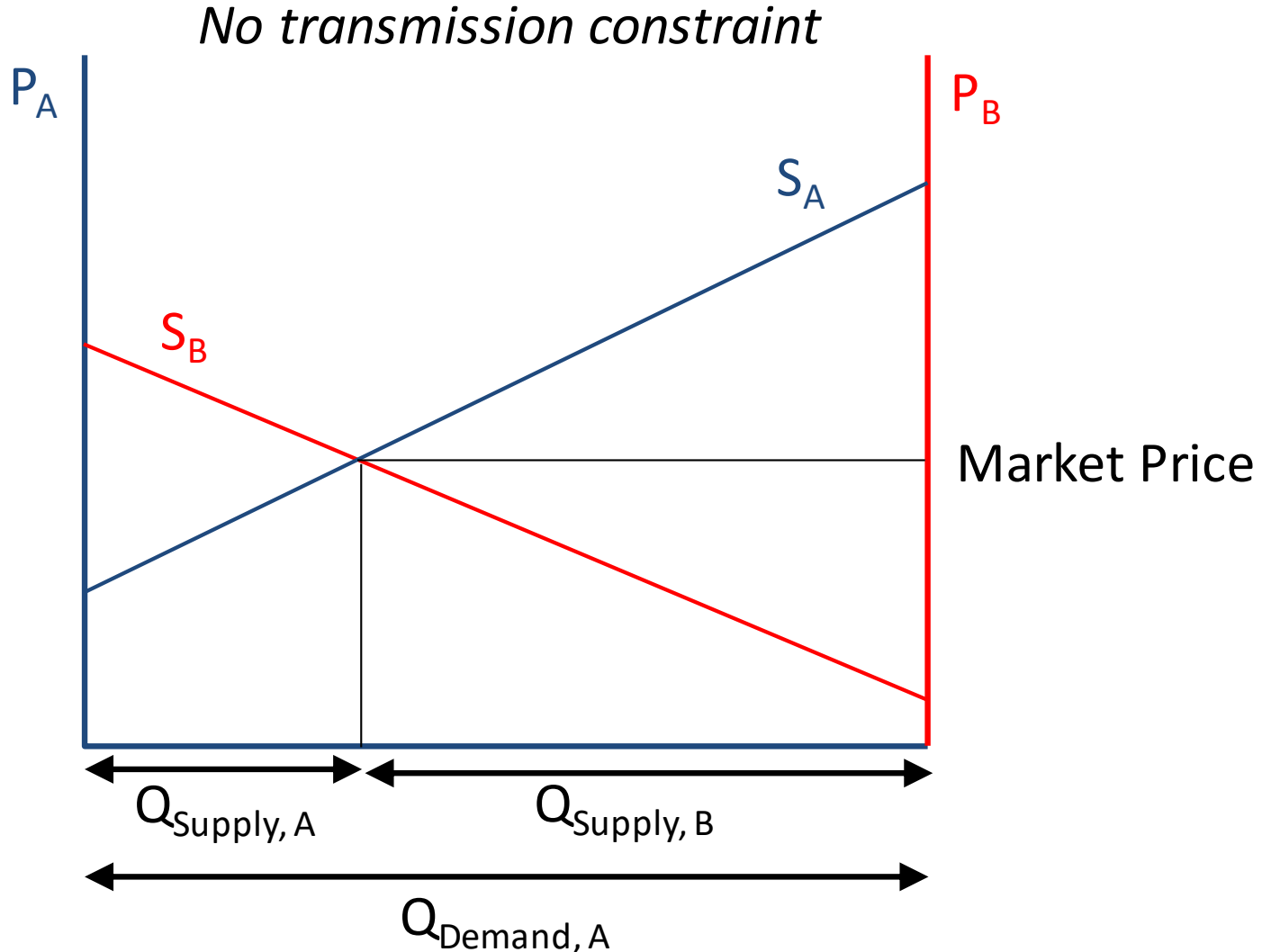
No transmission constraint



Transmission Constraints

- Consider two regions: A (supply and demand), B (supply)

If B tried to supply and more than $Q_{\text{Supply},B}$, the incremental energy could be supplied more cheaply by supply from A (and vice-versa)



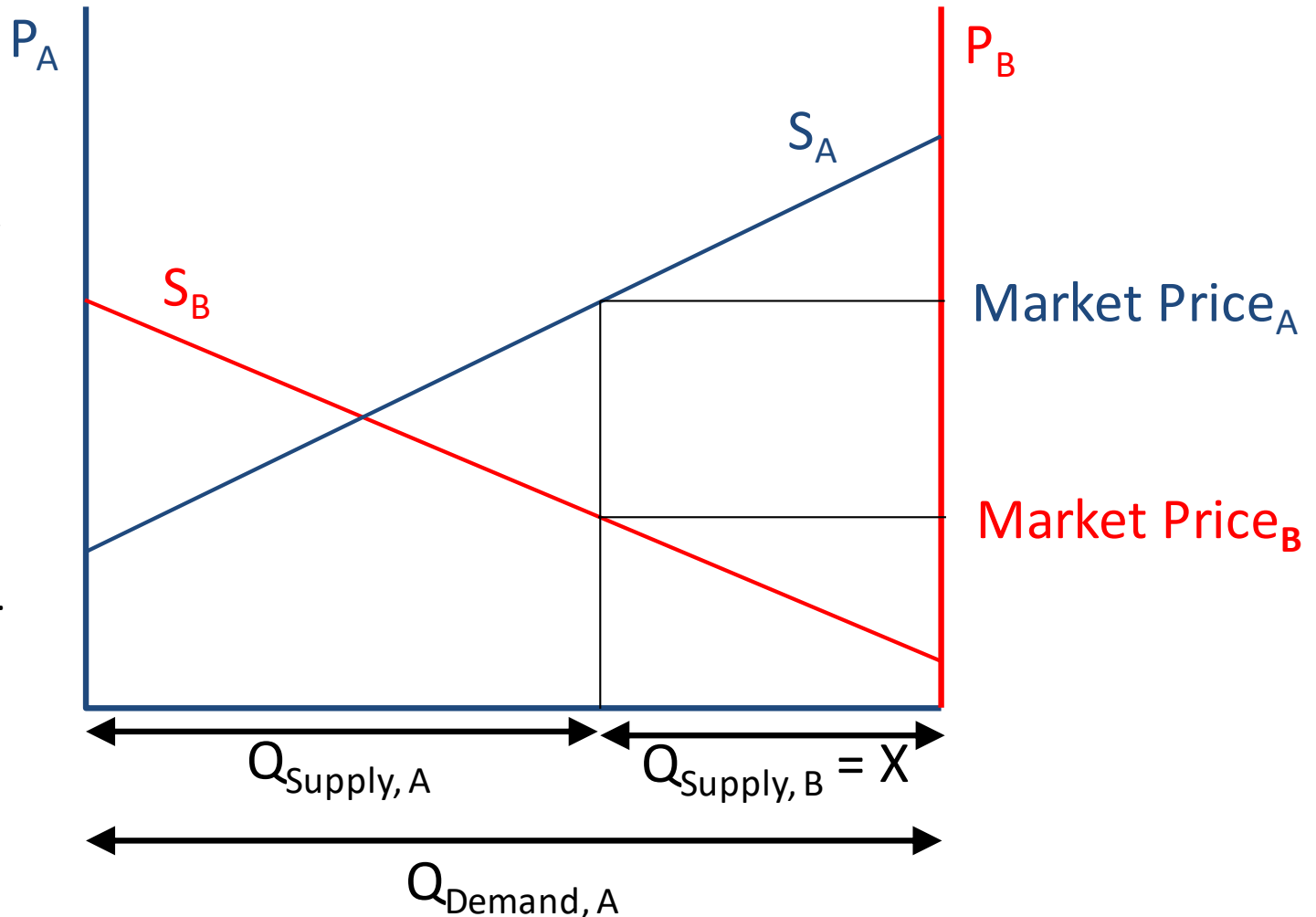
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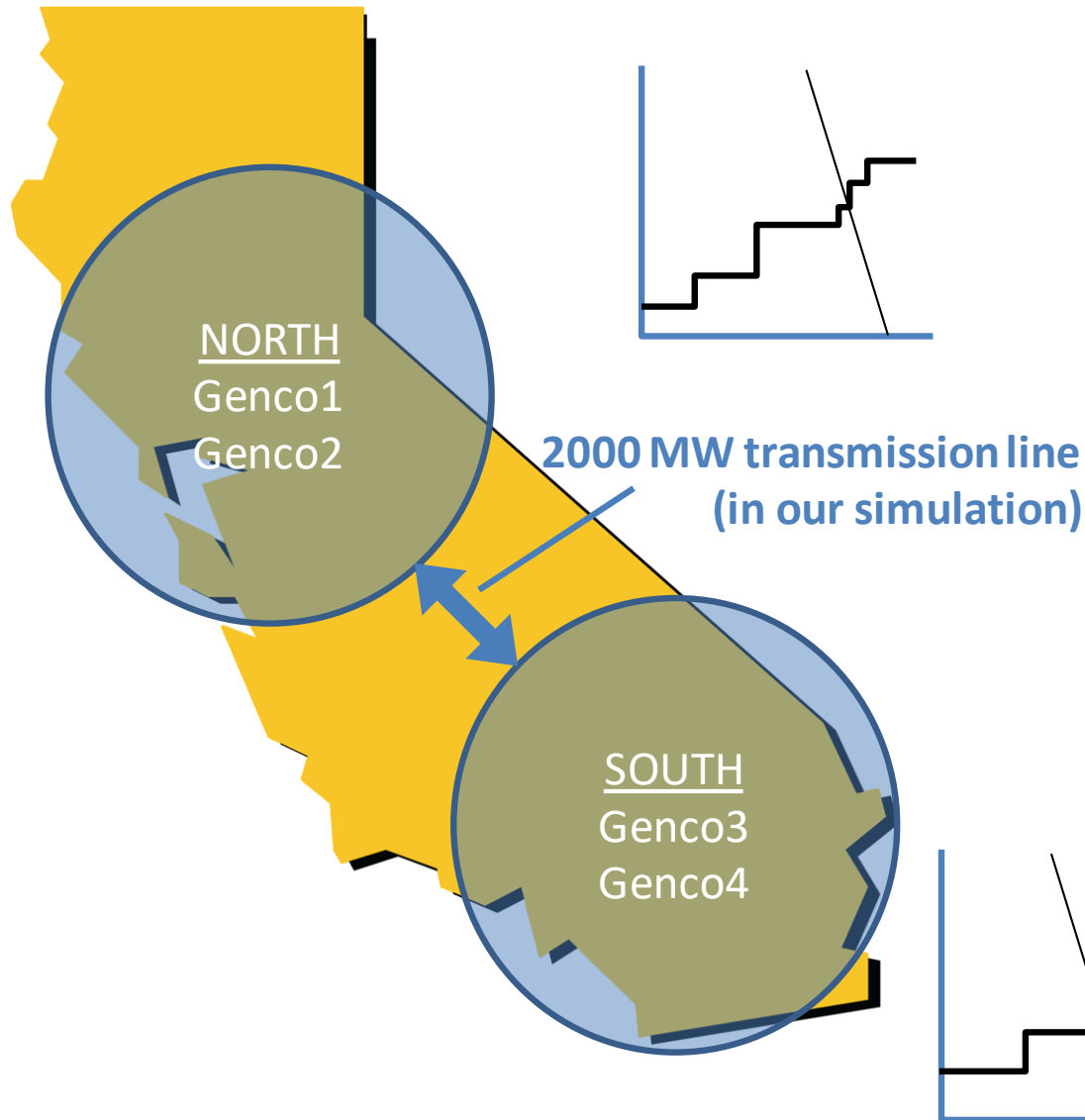
Transmission constraint = X

ISO must show B a lower price so it doesn't oversupply and fry the transmission line.

ISO must show A a higher price so it generates more energy in order to meet demand at A.

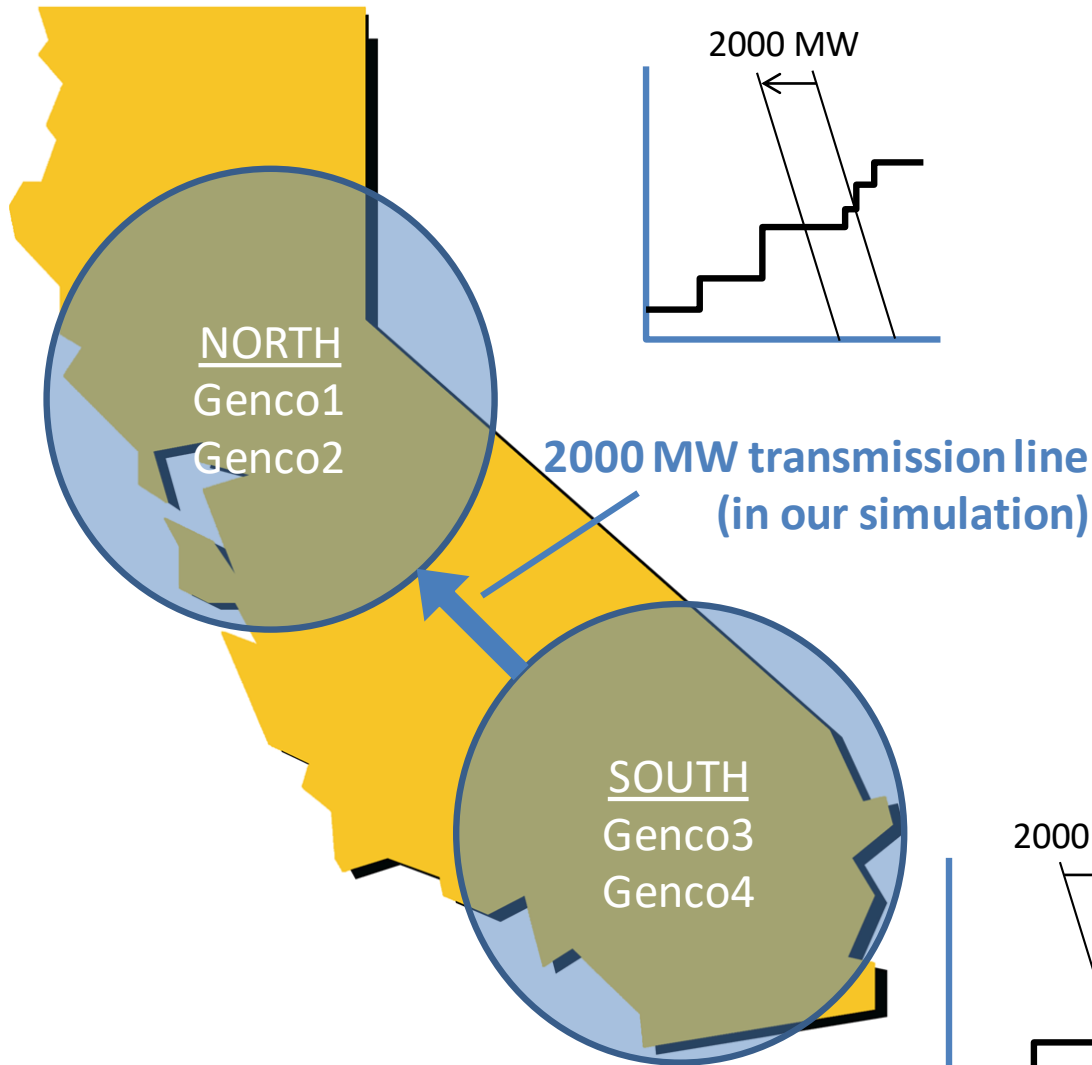


Transmission Constraints in the Game



- 1) Compute market equilibrium assuming no transmission constraint
- 2) Compute how much power from one region would flow to the other
- 3) If figure is greater than transmission line capacity, constraint binds
- 4) Compute market equilibrium again, treating North and South as separate regions
 - Demand shifted out by transmission capacity for region that is long on power, in for region that is short on power

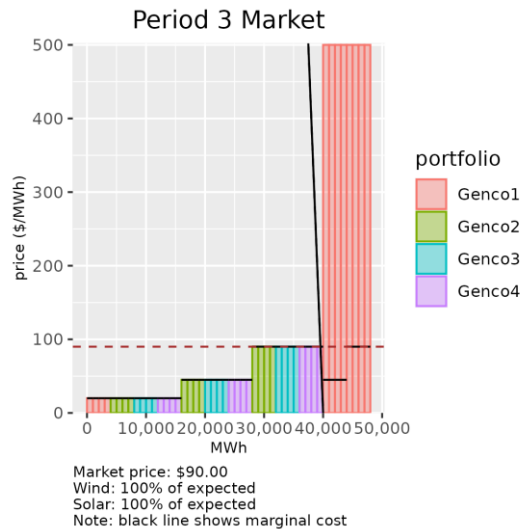
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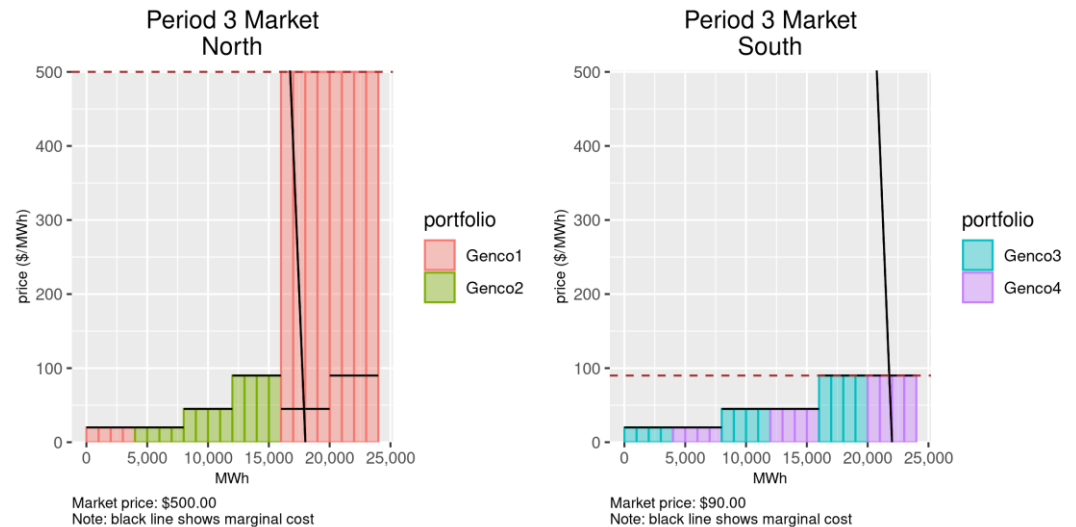
Effect of Transmission Congestion and Offer Behavior

No transmission constraint,
Genco1 offers \$500/MWh for
Intermediate and Peak units



Period 3 profits
Genco1: \$128,000
Genco2: \$308,000
Genco3: \$308,000
Genco4: \$308,000
TOTAL: \$1.05M

2000 MW transmission constraint,
Genco1 offers \$500/MWh for
Intermediate and Peak units



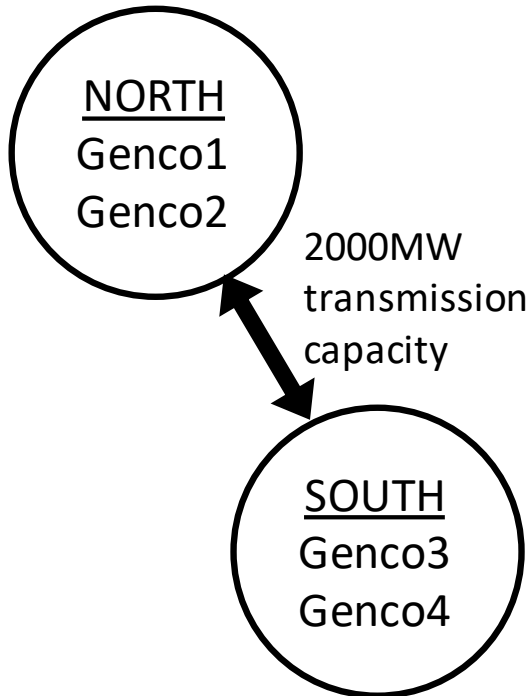
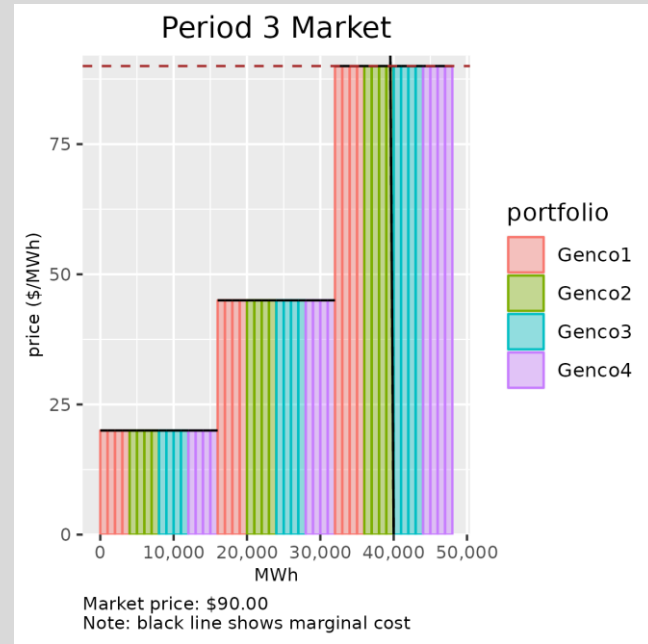
Period 3 profits
Genco1: \$1.84M
Genco2: \$4.97M
Genco3: \$52,000
Genco4: \$52,000
TOTAL: \$6.91M

- Congestion can make supply less competitive

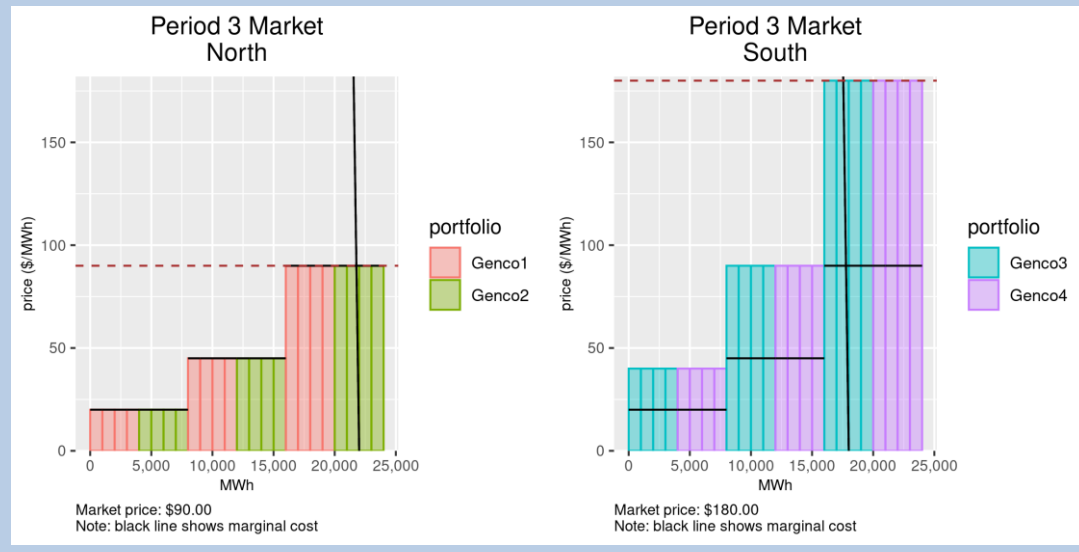
4-period game with a 2000MW transmission constraint

Hour	Approx. North Demand (MWh)	Approx. South Demand (MWh)	North Price, if all units offer MC (\$/MWh)	South Price, if all units offer MC (\$/MWh)
4am	4000	4000	20	20
10am	10000	10000	45	45
4pm	20000	20000	90	90
10pm	14000	14000	45	45

4pm hour:
If all Gencos offer MC



4pm hour:
If South Gencos (3 & 4) offer 2x MC



Game #3

Transmission Constraint

- Uniform-Price Auction (for this and all subsequent games)

Forward Contracts

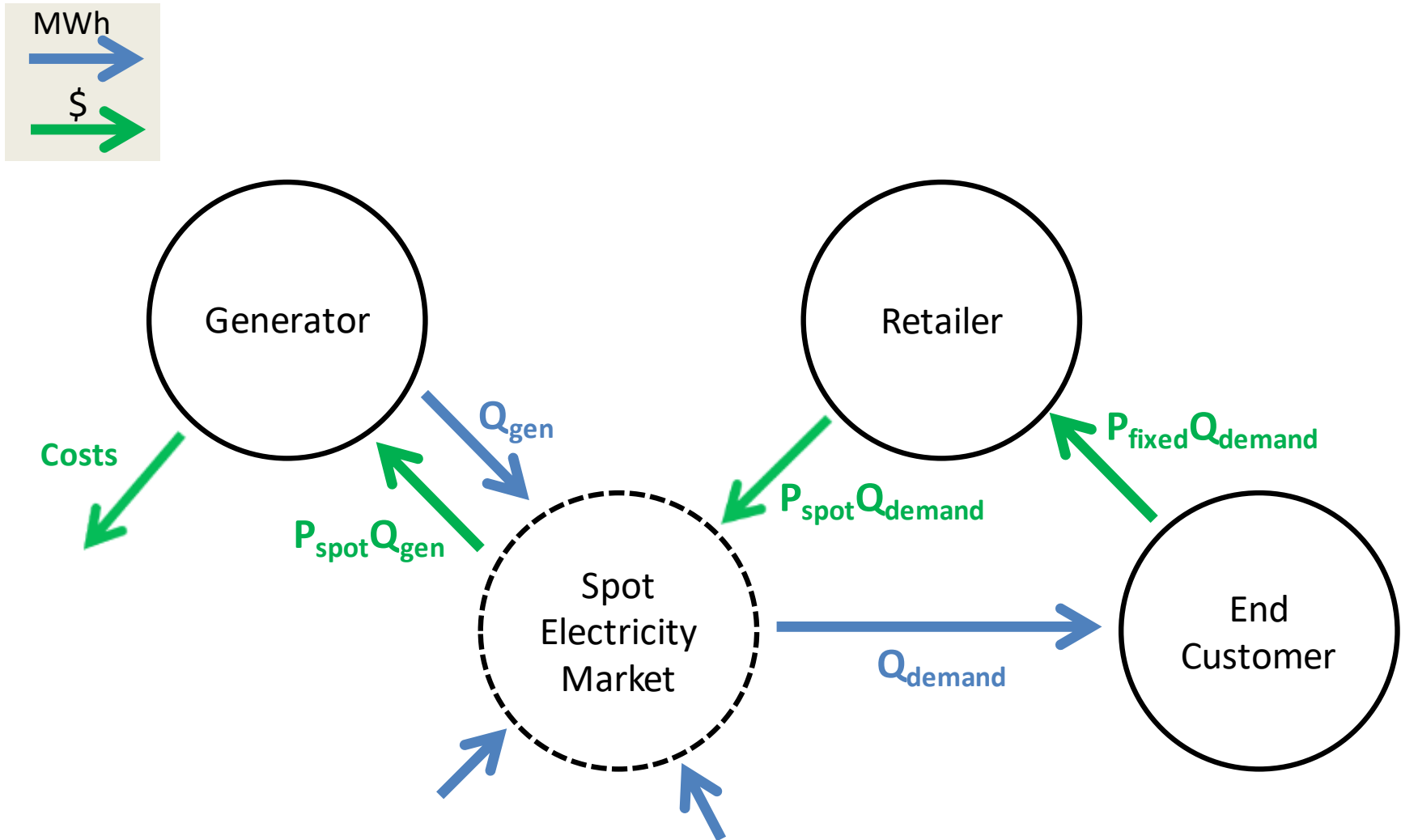
Forward Contracts and Genco Incentives

- Gencos selling into the short-term market have a strong incentive to exercise unilateral market power (through price offers and/or availability of generating capacity) in order to push up the short-term electricity price
- However, if gencos have already sold a significant quantity of energy under forward contracts, they no longer have this incentive to increase the short-term price for this quantity of energy. (We will see why this is true.)
- This means that forward contract obligations can be a powerful regulatory tool to improve market functioning
- California's electricity crisis of 2000-2001 occurred in part because policymakers did not understand how forward contracts could blunt genco incentives to exercise unilateral market power (see Wolak, "Diagnosing the California Electricity Crisis," 2003)

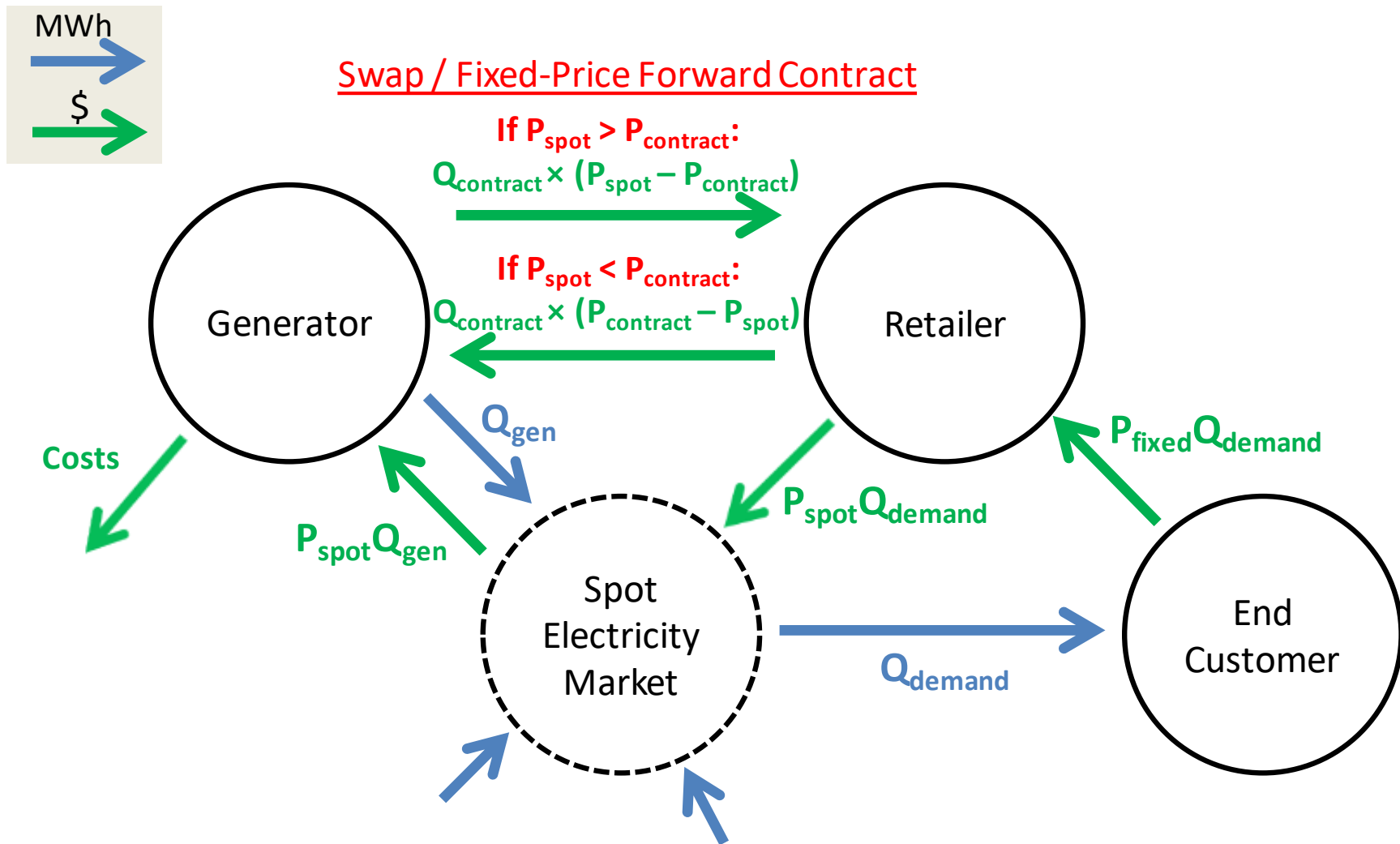
Electricity Retailers

- In the absence of forward contracts, retailers must buy all the energy their customers use at the spot electricity price (just as gencos sell all their energy at the spot electricity price)
- Retailers can be regulated monopolies or, where retail competition is allowed, companies that compete against each other for customers
- Regulated monopoly retailers sell electricity to their end customers at a regulated – and often fixed – price per kWh
 - On average, the price retailers receive from their customers must be sufficient to recover the costs of purchasing electricity in the wholesale market!
- Forward contracts are one way retailers can hedge their risk that spot prices will be too high

Electricity Market: Generation + Retail



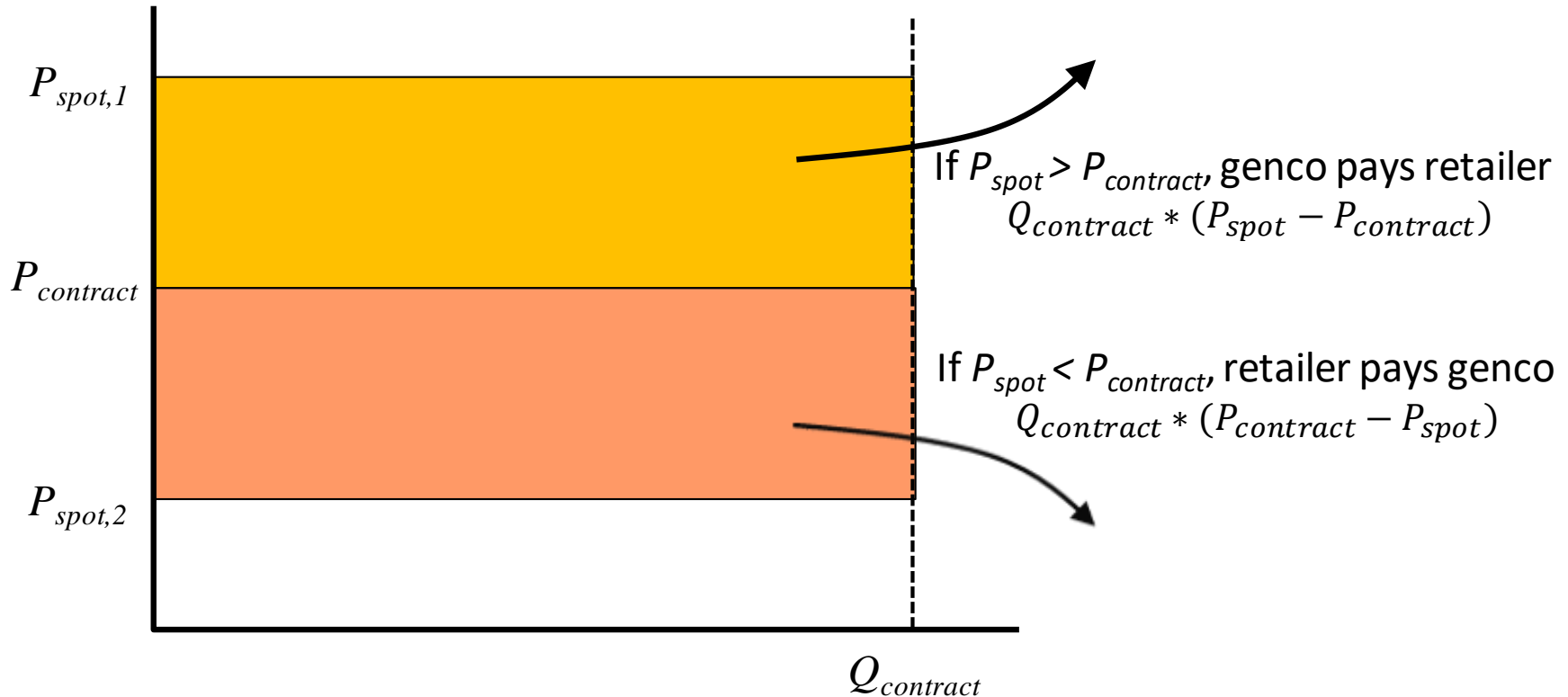
Hedging Spot Price Risk with Forward Contracts



Forward contracts are purely financial: counterparties make “difference payments” to each other

Mechanics of a Fixed-Price Forward Contract

$$\text{Difference Payments} = Q_{\text{contract}} * (P_{\text{contract}} - P_{\text{spot}})$$



- Contract is purely financial (i.e. “You write a check to me if $P_{\text{spot}} > P_{\text{contract}}$, I’ll write a check to you if $P_{\text{spot}} < P_{\text{contract}}$ ”)
- The above shows the logical hedging direction for gencos and retailers (protect gencos from low spot prices and retailers from high ones), but contract doesn’t have to be in this direction—and it doesn’t have to be between operational players at all!

Incentives for Generators with Forward Contracts

$$\begin{aligned}
 \text{Revenue from spot sales} & \qquad \qquad \qquad \text{"Difference payments"} \\
 & \qquad \qquad \qquad \qquad \qquad \qquad \text{under contract} \\
 \text{Var. Profits} &= \overbrace{[Q_{spot}(P_{spot}-MC)]} + \overbrace{[Q_{contract}(P_{contract} - P_{spot})]} \\
 &= \underbrace{[(Q_{spot} - Q_{contract})(P_{spot}-MC)]}_{\text{Seek to maximize}} + \underbrace{[Q_{contract}(P_{contract}-MC)]}_{\text{Constant}} \\
 & \qquad \qquad \qquad \qquad \qquad \qquad \qquad \qquad \qquad \text{(assuming constant MC)}
 \end{aligned}$$

- Q_{spot} is the genco's output, P_{spot} is the spot price of electricity
- If $Q_{contract} = Q_{spot}$, "looks like" genco sold all electricity at $P_{contract}$ (even though what "really happened" is they sold Q_{spot} at P_{spot} and then gave/received a difference payment that made it look like they had sold it at $Q_{contract}$)
- As shown in the rearrangement of terms in the second line, gencos have very different incentives once they've sold contracts

Incentives for Generators with Forward Contracts

$$\begin{aligned}
 \text{Var. Profits} &= \overbrace{[Q_{spot}(P_{spot} - MC)]}^{\text{Revenue from spot sales}} + \overbrace{[Q_{contract}(P_{contract} - P_{spot})]}^{\text{"Difference payments" under contract}} \\
 &= \underbrace{[(Q_{spot} - Q_{contract})(P_{spot} - MC)]}_{\text{Seek to maximize}} + \underbrace{[Q_{contract}(P_{contract} - MC)]}_{\text{Constant (assuming constant MC)}}
 \end{aligned}$$

$P_{contract}$ should have no influence on your offer strategy in the short-term market!

Now, offering high prices on all your units can:

- 1) Increase P_{spot} , making the $P_{spot} - MC$ term more positive
 - 2) Decrease Q_{spot} , making the $Q_{spot} - Q_{contract}$ term more negative
- i.e. your profits go down!

Gencos are incentivized to offer MC for all units up until they cover $Q_{contract}$!
 (In effect, offering MC helps the genco "procure" $Q_{contract}$ as cheaply as possible, generating it if $P_{spot} > MC$, and buying from the market if $P_{spot} < MC$.)

Incentives for Generators with Forward Contracts

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 \text{Revenue from spot sales} & \qquad \qquad \qquad \text{"Difference payments" under contract} \\
 \text{Var. Profits} &= \overbrace{[Q_{spot}(P_{spot} - MC)]} + \overbrace{[Q_{contract}(P_{contract} - P_{spot})]} \\
 &= \underbrace{[(Q_{spot} - Q_{contract})(P_{spot} - MC)]}_{\text{Seek to maximize}} + \underbrace{[Q_{contract}(P_{contract} - MC)]}_{\text{Constant (assuming constant MC)}}
 \end{aligned}$$

Generators are incentivized to have enough generating capacity available to cover $Q_{contract}$. Otherwise, the $Q_{spot} - Q_{contract}$ term is guaranteed to be negative, and they have no physical hedge against the case where P_{spot} goes very high, driving down their profits.

Real-life example: How California “bought out” the market power of generators after the 2000-2001 electricity crisis

Suppose that during Winter of 2001 generators believe spot prices for

June 01 to June 02 = \$250/MWh

June 02 to June 03 = \$150/MWh

June 03 to future = \$40/MWh

Why did spot price expectations vary like this as a function of time horizon?

Suppose California wishes to buy a 10-year contract with $1/20$ of energy in first year, $1/10$ in second year, and $17/20$ of energy in years 3 to 10.

What price will generator charge?

Generator requires a price of at least \$61.50
 $= (250 * 1/20 + 150 * 1/10 + 40 * 17/20)$ to agree to contract

Note: Above numbers based on actual forward prices of power in winter 2001 and actual pattern of energy purchased in contracts.

California could have saved itself a lot of pain if it had bundled generation assets with “vesting contracts” (forward contracts selling a certain quantity of energy) when it restructured!

Game #4

Pre-Assigned Forward Contracts
with Transmission Constraints

Day-Ahead Markets

Benefits of physically-feasible day-ahead markets

- System operator simultaneously minimizes cost to meet bid-in demand at all locations in grid for all 24 hours of following day recognizing all relevant transmission network constraints
 - Can account for minimum uptime, minimum downtime, minimum operating level constraints, ramp rate constraints for all generation units
 - Day-ahead market includes start-up and minimum load costs in market solution (decision to turn unit on and/or operate at minimum load)
 - Market-operator solves mixed-integer programming problem for all 24 hours of the day at once to determine locational marginal prices of energy and day-ahead energy sales and purchases
 - Real-world optimization will include many other variables, such as start-up times, ramp rates, etc.
- ***Advance planning should produce more efficient real-time dispatch of generation units***

Scheduling demand in a day-ahead market

- Demand purchases in day-ahead market and bears full cost of an inaccurate forecast of real-time consumption
- Real-time market clears to meet actual demand at all locations in transmission network which provides financial incentive to schedule as accurately as possible in day-ahead market
 - Deviations between day-ahead schedules and real-time consumption of energy are settled at the real-time price
 - Buy additional energy at real-time price and sell unconsumed energy at real-time price

Day-ahead commitments are functionally equivalent to fixed-price forward contracts

- Sale of energy in day-ahead market means that a supplier receives revenue for that energy regardless of real-time output of its generation unit
 - Seller of 40 MWh at a price of \$25/MWh in day-ahead market paid \$1,000
 - Any deviation from day-ahead schedule of 40 MWh is cleared in real-time market at real-time price
 - If supplier only produces 30 MWh in real-time, it must purchase 10 MWh of day-ahead sale from real-time market at real-time price
 - Profits = $P(\text{DA})Q(\text{DA}) + P(\text{RT})(Q(\text{RT}) - Q(\text{DA})) - C(Q(\text{RT}))$
- Purchase of energy in day-ahead market means that buyer must pay for that energy regardless of actual real-time consumption
 - Buyer of 100 MWh in day-ahead market at \$40/MWh and pays \$4,000 regardless of real-time consumption
 - If load-serving entity consumes 110 MWh, must buy additional 10 MWh in real-time market at real-time price
 - If load-serving entity consumes 90 MWh, it sells 10 MWh not consumed in real-time market at real-time price
 - Profits = $P(\text{Retail})Q(\text{Retail}) - P(\text{DA})Q(\text{DA}) - P(\text{RT})(Q(\text{Retail}) - Q(\text{DA}))$

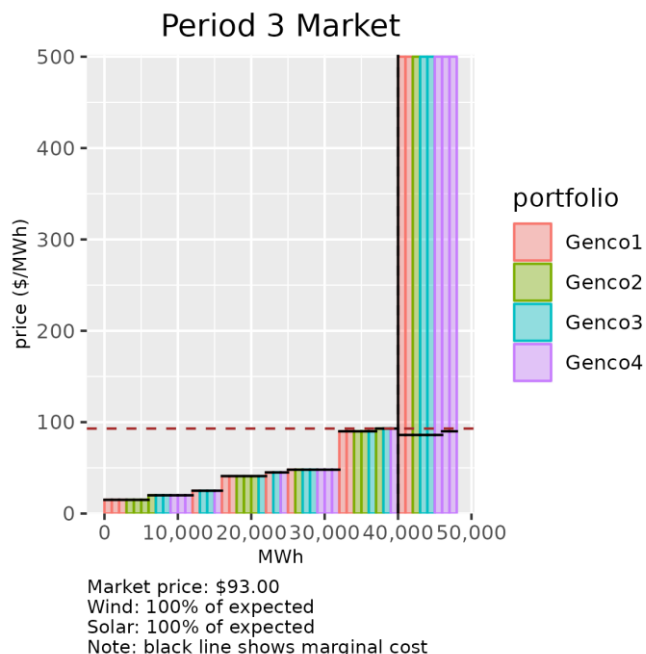
Unit startup costs in a sample game

- Simple model of startup costs in our game: If a unit runs at all during a day, it incurs startup costs once for that day
- With introduction of startup costs, the total daily costs of a unit (excluding fixed costs) depend on: 1) its startup costs, 2) its marginal cost, and 3) how much it runs during the day
- A, B, and C variants of Base, Intermediate, and Peak units (assigned randomly to gencos) have different balance of marginal cost and startup cost
- Including startup costs means the lower-marginal-cost variant is not necessarily lower-cost over the day

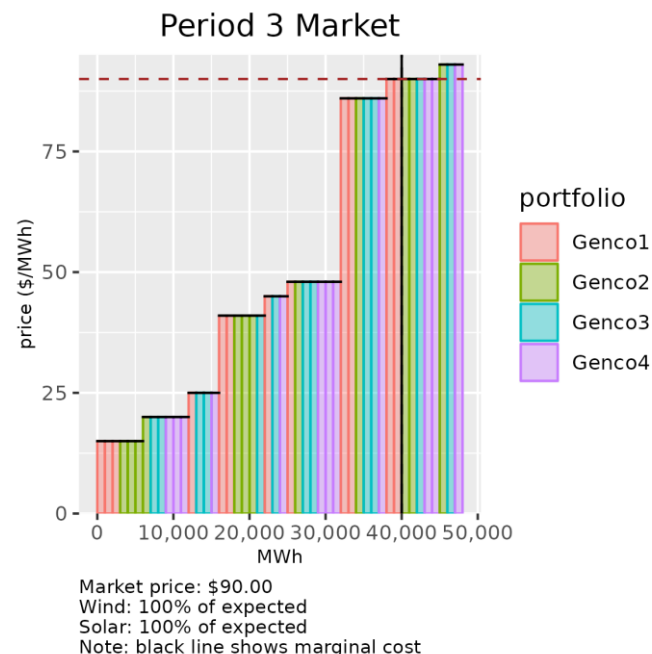
Type	Marginal Cost (\$/MWh)	Fixed Cost per 1000MW (\$/hr)	Startup Cost per 1000MW (\$)	Daily cost (excluding fixed cost) by number of periods run (\$):			
				1	2	3	4
BaseA	15	25,000	37,000	52,000	67,000	82,000	97,000
BaseB	20	25,000	21,000	41,000	61,000	81,000	101,000
BaseC	25	25,000	10,000	35,000	60,000	85,000	110,000
IntermediateA	41	10,000	21,000	62,000	103,000	144,000	185,000
IntermediateB	45	10,000	10,000	55,000	100,000	145,000	190,000
IntermediateC	48	10,000	5,000	53,000	101,000	149,000	197,000
PeakA	86	3,000	13,000	99,000	185,000	271,000	357,000
PeakB	90	3,000	4,000	94,000	184,000	274,000	364,000
PeakC	93	3,000	500	93,500	186,500	279,500	372,500

Efficiency benefits of multi-settlement market

Follow day-ahead schedule
in real-time market:



Make all units available
in real-time market:



Generation costs for day = \$6,227,686

Generation costs for day = \$6,279,366
(0.83% higher)

- Efficiency benefits would be much more significant if we considered additional real-world factors in the day-ahead market optimization
- **Key point: *The more the day-ahead market predicts actual real-time conditions, the more we can realize the efficiency benefits from day-ahead optimization***
 - This is why “convergence bidding” can produce cost savings

Day-Ahead Market with Renewable Energy

Day-ahead market rewards flexibility of supply (case 1)

- Consider a market with significant intermittent resources and supply of intermittent resources highly correlated across locations
- Dispatchable thermal unit sells 100 MWh at price of \$50/MWh in day-ahead market and intermittent resource sells 80 MWh in day-ahead market at same price
- In real-time, significantly less intermittent output is produced than was scheduled
 - Intermittent renewable unit produces 50 MWh, so must purchase 30 MWh from real-time market at \$90/MWh
 - Thermal unit must maintain supply and demand balance, which explains high real-time price relative to day-ahead price
 - Thermal unit sells 30 MWh at real-time of \$90/MWh
- Average price paid to intermittent unit:

$$\$26 = (80 \text{ MWh} * \$50/\text{MWh} - 30 \text{ MWh} * \$90/\text{MWh}) / 50 \text{ MWh}$$
- Average price paid to thermal unit:

$$\$59.23 = (100 \text{ MWh} * \$50/\text{MWh} + 30 \text{ MWh} * \$90/\text{MWh}) / 130 \text{ MWh}$$
- Dispatchable unit rewarded with higher average price than non-dispatchable intermittent unit, despite both units facing same prices in day-ahead and real-time markets

Day-ahead market rewards flexibility of supply (case 2)

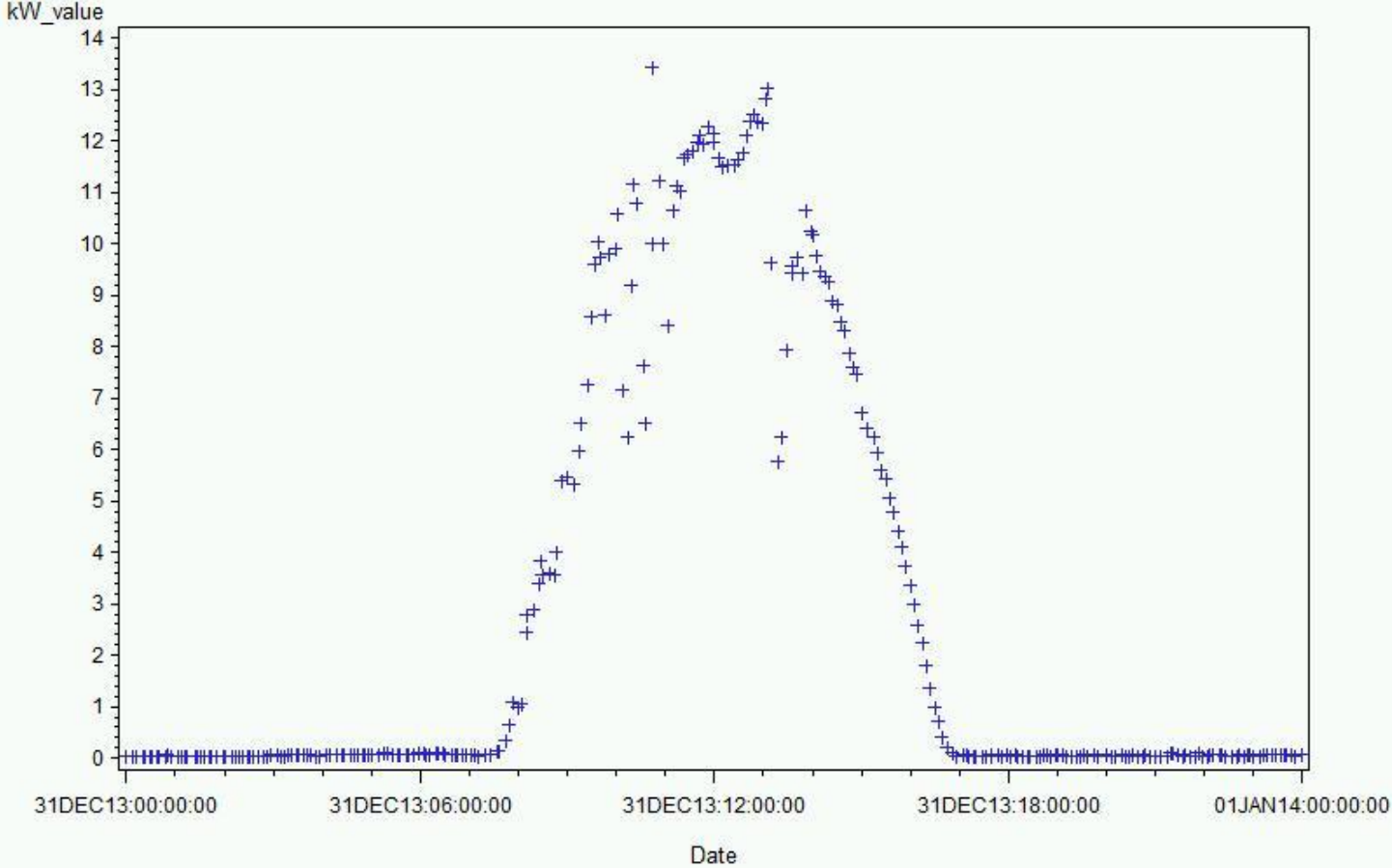
- Dispatchable thermal unit sells 130 MWh at price of \$50/MWh in day-ahead market and intermittent resource sells 50 MWh in day-ahead market at same price
- In real-time, significantly **more** intermittent output produced than scheduled
 - Low real-time price of \$20/MWh due to unexpectedly large intermittent output
 - Intermittent renewable unit produces 80 MWh, so it sells 30 MWh in real-time market at \$20/MWh
 - Thermal unit buys back 30 MWh in real-time at \$20/MWh
- Average price paid to intermittent unit:

$$\$38.75 = (50 \text{ MWh} * \$50/\text{MWh} + 30 \text{ MWh} * \$20/\text{MWh}) / 80 \text{ MWh}$$
- Average price paid to thermal unit:

$$\$59 = (130 \text{ MWh} * \$50/\text{MWh} - 30 \text{ MWh} * \$20/\text{MWh}) / 100 \text{ MWh}$$
- Dispatchable unit rewarded with higher average price than intermittent unit because it can reduce its output
- Day-ahead market rewards both upward and downward flexibility from both generation units and loads
 - More frequent (e.g. 5min) settlement in real-time further rewards flexibility

Intermittency: Solar

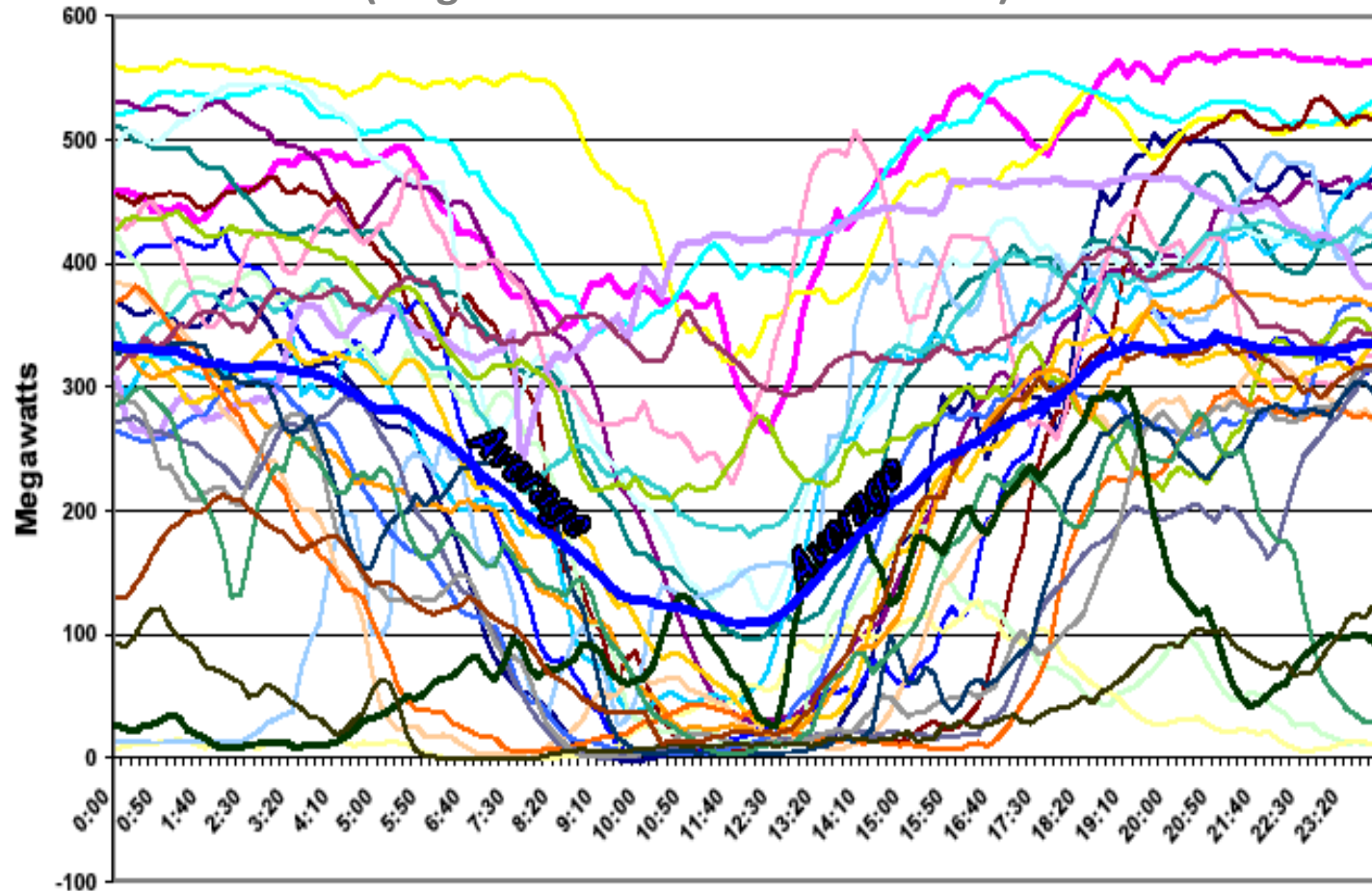
Profile of one day's generation from Stanford GSB (one building)



Intermittency: Wind

Tehachapi - June 2006
Daily Energy Production

(Large Wind Farm in Southern CA)

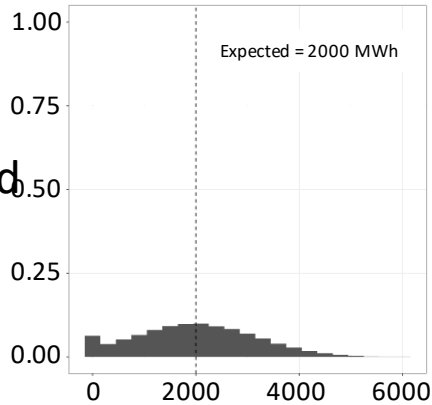


- Characteristic daily generation profile
- Significant variation about this profile

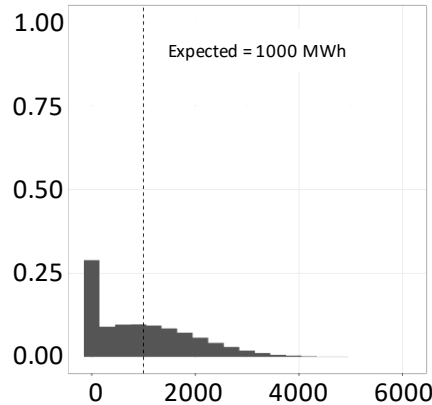
Stylized wind and solar units in our game

Unit Type	Expected Generation (MWh)				Variable Cost (\$/MWh)	Fixed cost (\$/hr)	Est. LCOE (\$/MWh)
	4am	10am	4pm	10pm			
Wind	2,000	1,000	1,000	2,000	\$0	\$45,000	\$30
Solar PV	0	3,000	3,000	0	\$0	\$60,000	\$40

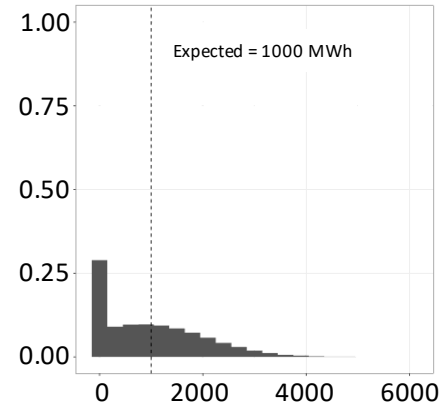
Period 1



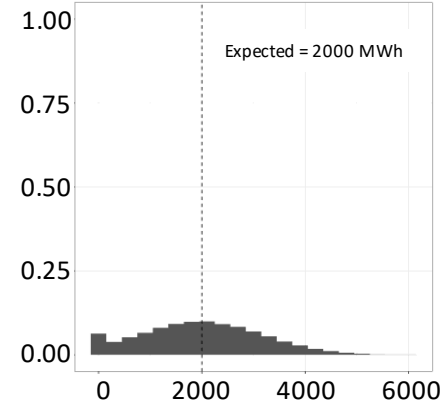
Period 2



Period 3

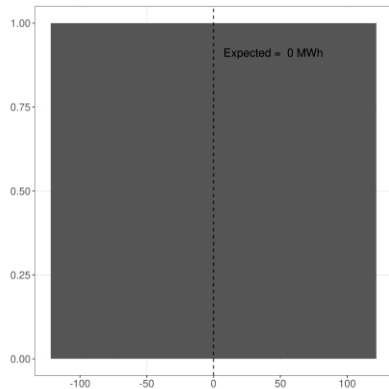


Period 4

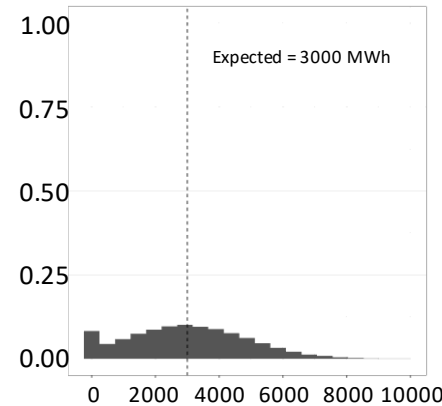


Wind

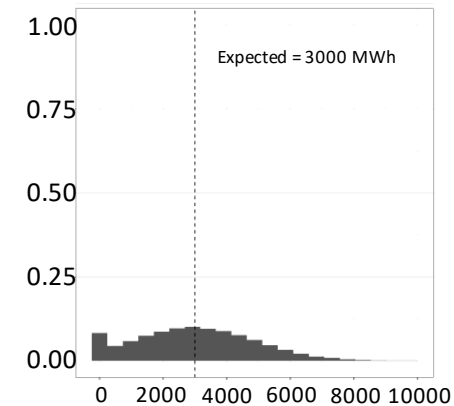
Period 1



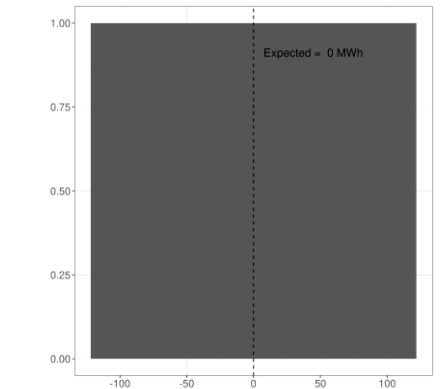
Period 2



Period 3

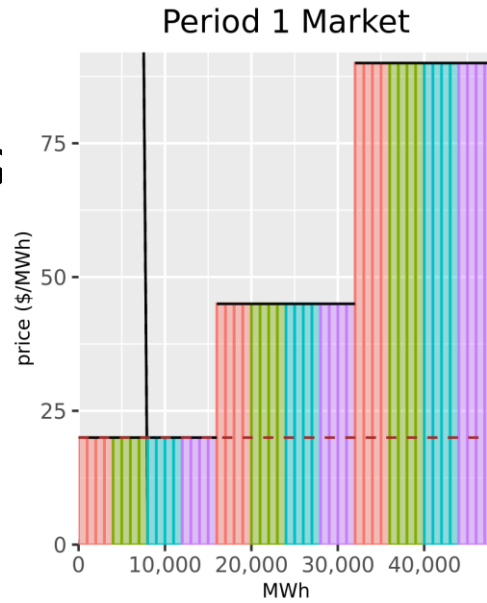


Period 4

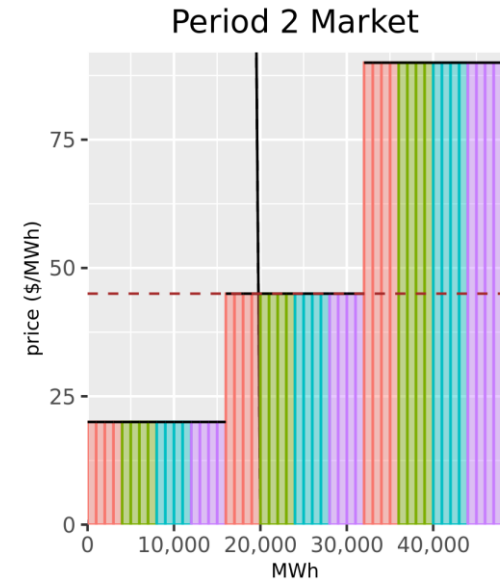


Solar

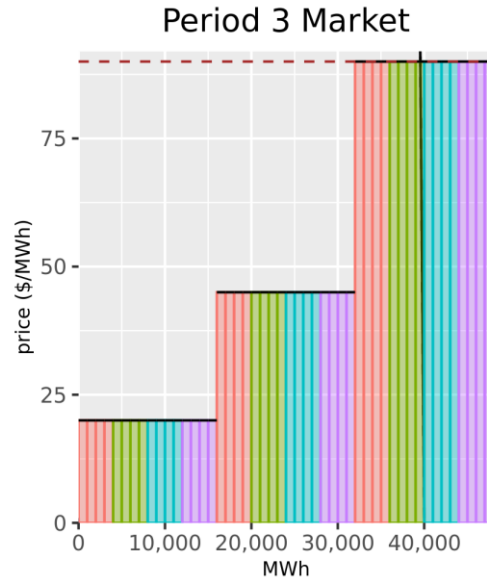
No renewables case



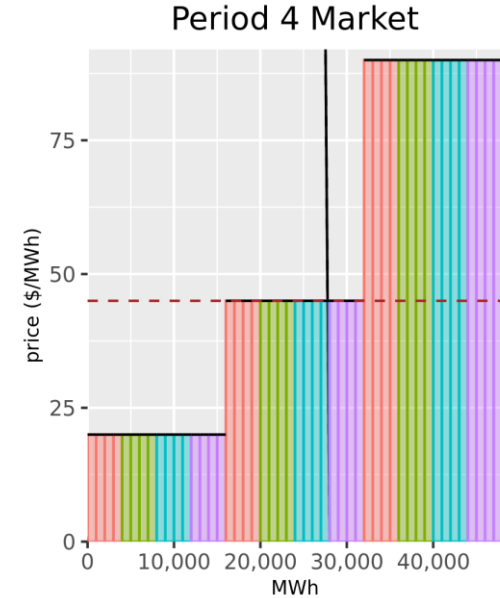
Market price: \$20.00
 Wind: 100% of expected
 Note: black line shows marginal cost



Market price: \$45.00
 Wind: 100% of expected
 Solar: 100% of expected
 Note: black line shows marginal cost



Market price: \$90.00
 Wind: 100% of expected
 Solar: 100% of expected
 Note: black line shows marginal cost

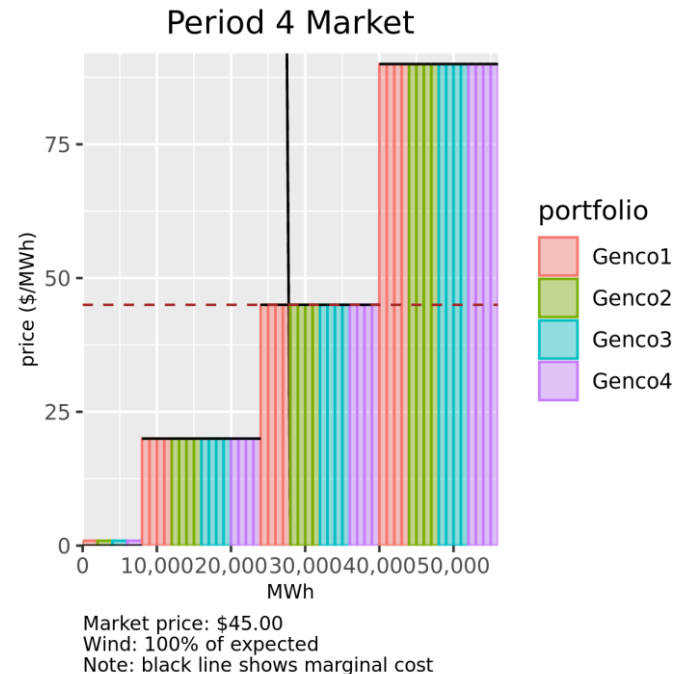
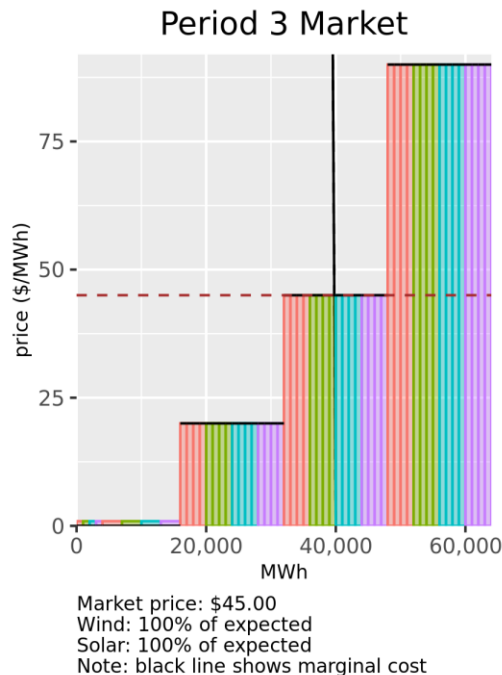
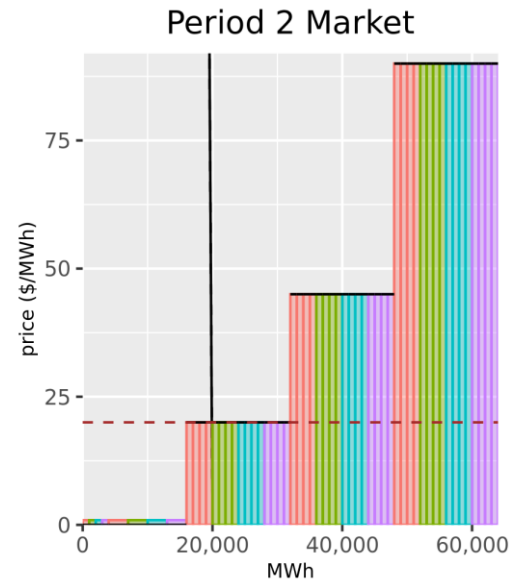
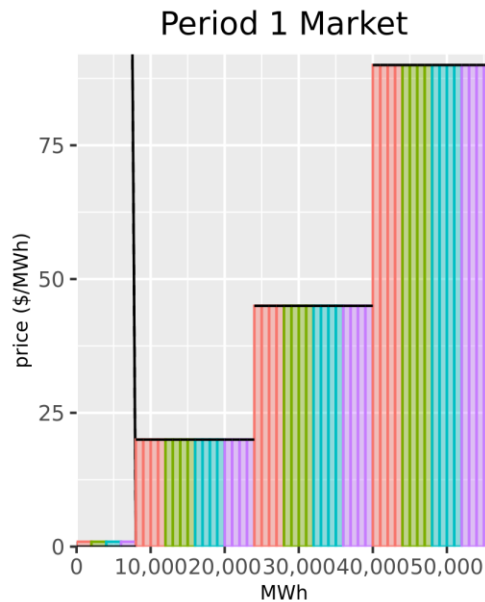


Market price: \$45.00
 Wind: 100% of expected
 Note: black line shows marginal cost

Hour	Approx. Demand (MWh)	Expected Price (\$/MWh)
4am	8000	20
10am	20000	45
4pm	40000	90
10pm	28000	45

Profit per genco
 = \$52,000

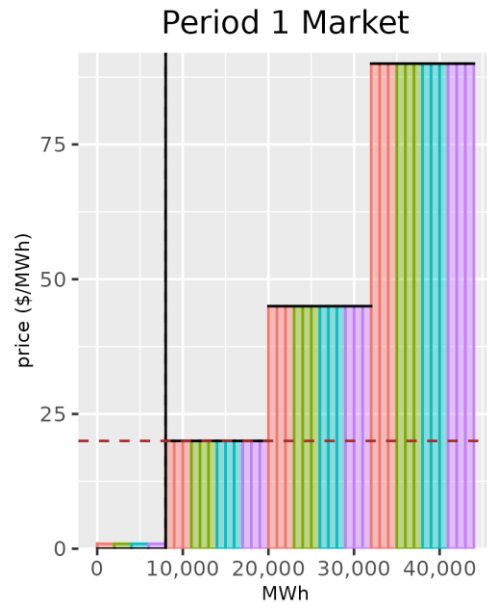
50% expected renewable generation (if wind and solar exactly as forecast)



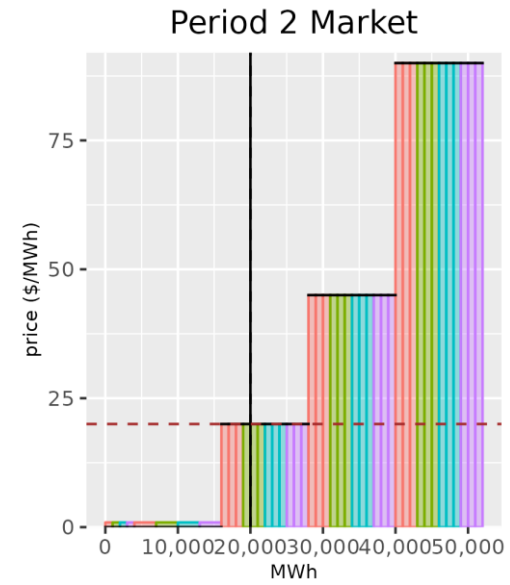
Hour	Approx. Demand (MWh)	Expected Price (\$/MWh)
4am	8000	-20
10am	20000	20
4pm	40000	45
10pm	28000	45

Profit per genco
= **-\$438,000**

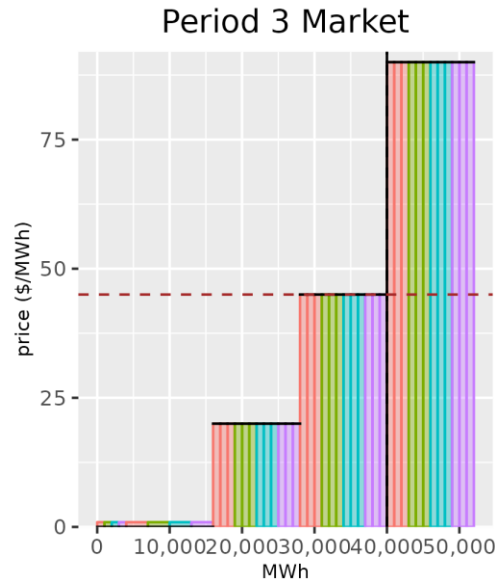
50% expected renewable generation (if wind and solar exactly as forecast), reduced portfolios



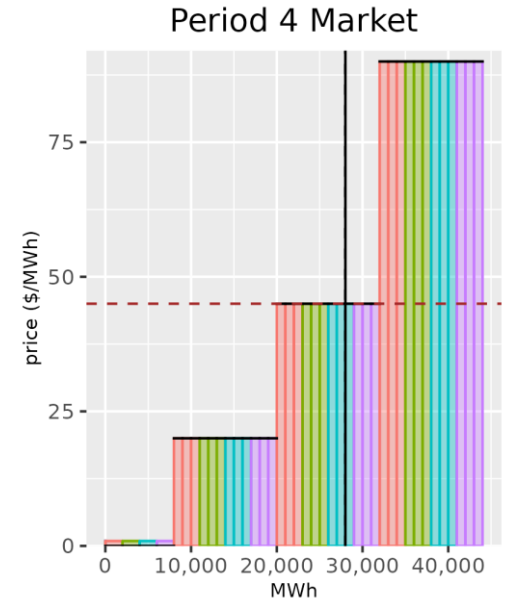
Market price: \$20.00
Wind: 100% of expected
Note: black line shows marginal cost



Market price: \$20.00
Wind: 100% of expected
Solar: 100% of expected
Note: black line shows marginal cost



Market price: \$45.00
Wind: 100% of expected
Solar: 100% of expected
Note: black line shows marginal cost



Market price: \$45.00
Wind: 100% of expected
Note: black line shows marginal cost

Hour	Approx. Demand (MWh)	Expected Price (\$/MWh)
4am	8000	-20
10am	20000	20
4pm	40000	45
10pm	28000	45

Profit per genco
= **-\$336,000**

Game #5

Day-Ahead Market

with Variable Renewable Energy

Thank you