Price Formation Enhancements

Technical Workshop

11/16/2022

Workshop Objectives

- Discuss initiative “phasing”
- Develop a set of price formation principles with which to evaluate pricing methods
- Walk through a set of simple examples to build foundational understanding of how market prices are formed

Phase 1	Phase 2	Phase 3
Technical workshops to prepare for Phase 2 items	Proposals beginning after Phase 1 complete	Proposals beginning after Phase 2 complete

Technical Workshops

- Pricing principles
- Price formation examples
- Fast-start pricing initial framework
- Fast-start pricing evaluation metrics
- Price formation and Sept '22 events

- Scarcity Pricing
- Fast-Start Pricing
- MPM "Grouping" Approach
- Extended FRP horizon

- Multi-Interval Optimization/BCR
- Replacement Reserves and other changes to facilitate co-optimized AS

Mike Cadwalader

Atlantic Economics

- Mike Cadwalader is President of Atlantic Economics
- 28 years experience in electricity market design
- Previously worked for Putnam, Hayes & Bartlett and LECG before founding Atlantic Economics in 2010
- Extensive involvement in the design and development of the NYISO market
  - Developed the approach the NYISO uses to construct a supply curve that incorporates the commitment costs of fast-start units, which it uses in fast-start pricing
  - Also involved in areas related to price formation (e.g., ancillary services pricing, shortage/scarcity pricing)
- Additional work related to electricity market development in Ontario, MISO, PJM, and California

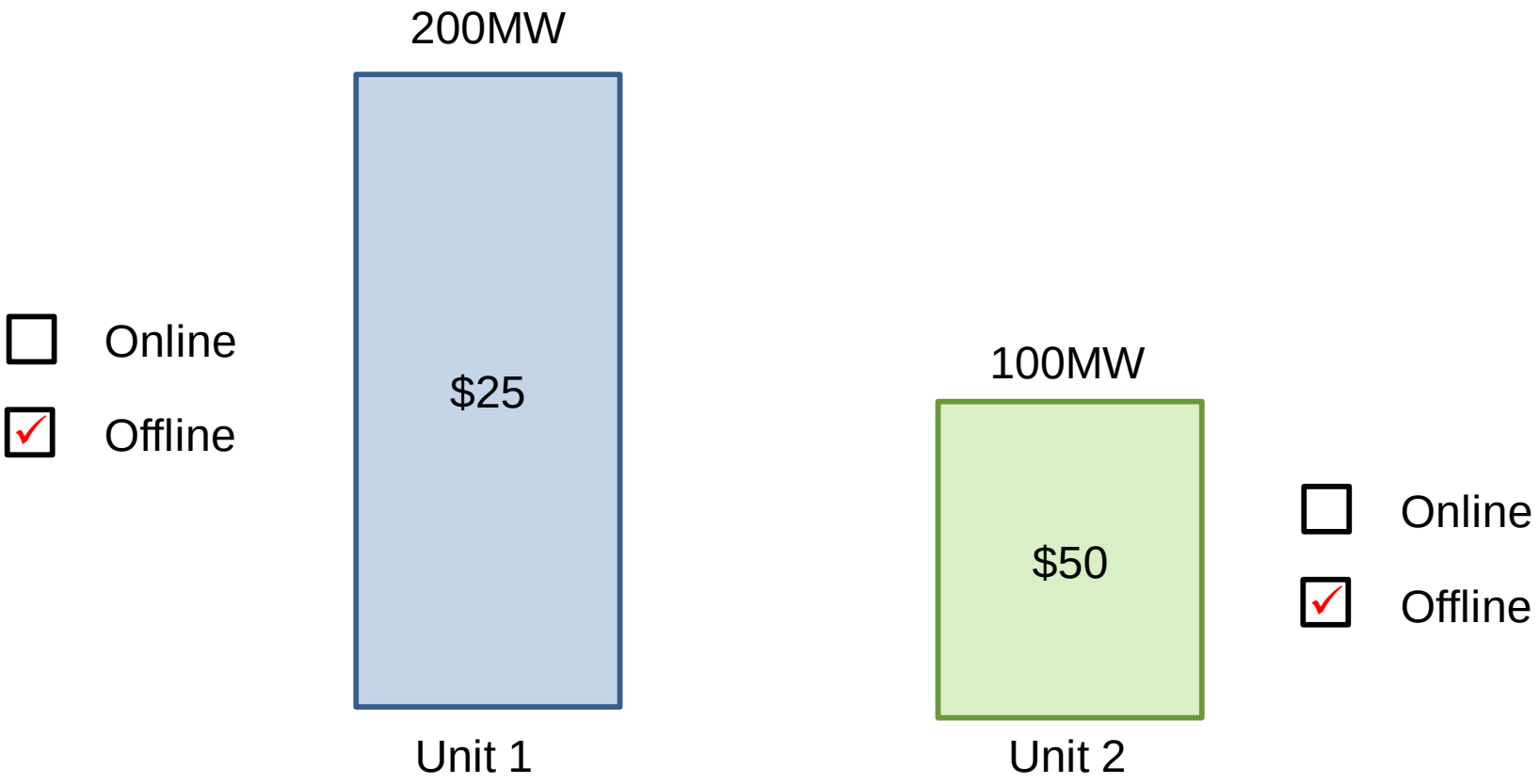
Price Formation Principles

1. Prices should reflect the marginal cost of meeting demand in a way that minimizes production costs/maximizes market surplus.
2. The market clearing process should incentivize bidding that reflects actual costs.
3. Prices should incentivize participants to follow their market schedules and dispatch.
4. Prices should reflect the short-term operational needs of the system and facilitate reliable operations.
5. Prices should help incentivize investments in competitive resources that can provide energy and grid services at lower cost.
6. Prices should be transparent so market participants understand price characteristics, volatility, risk, and revenue opportunities.

Example setup

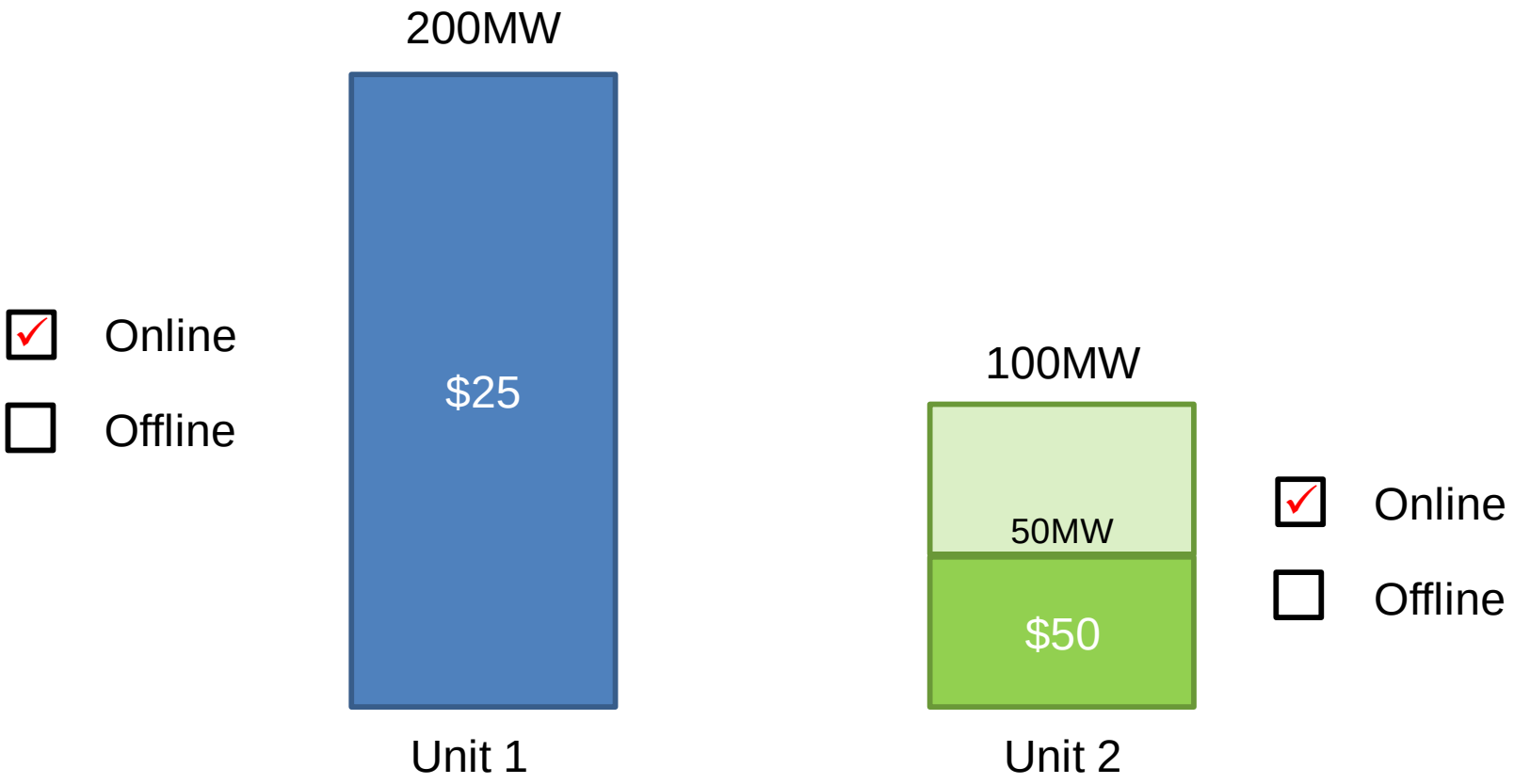
- Simple examples to keep concepts clear
  - These are generalized “textbook” examples – not intended to fully represent CAISO market bidding, processes, or settlement
- Focus is on gaining understanding of pricing concepts and developing common terminology
- Two generators (200MW baseload and 100MW peaker) serving 250MW of demand
- Assume offers reflect actual costs and no market power
- Start up time = 0 minutes

Example #1 – Both resources fully dispatchable
Demand = 250MW



How should we dispatch these units to serve 250MW of demand while minimizing production costs?

Example #1 – Both resources fully dispatchable
Demand = 250MW



Example #1 – Both resources fully dispatchable Demand = 250MW

Unit	Energy Award	Offer Price	Production Cost
1	200MW	$25	$5,000
2	50MW	$50	$2,500
	250MW		**$7,500**

- What price does the market set in this example?
- How would you serve the next increment of demand and what would it cost?

Example #1 – Both resources fully dispatchable Demand = 250MW

Unit	Energy Award	Offer Price	Production Cost
1	200MW	$25	$5,000
2	51MW	$50	$2,550
	251MW		**$7,550**

- The next increment of demand would be served by Unit 2 at an offer price of $50
- Therefore, the market price is set at $50
- This represents “marginal cost pricing”

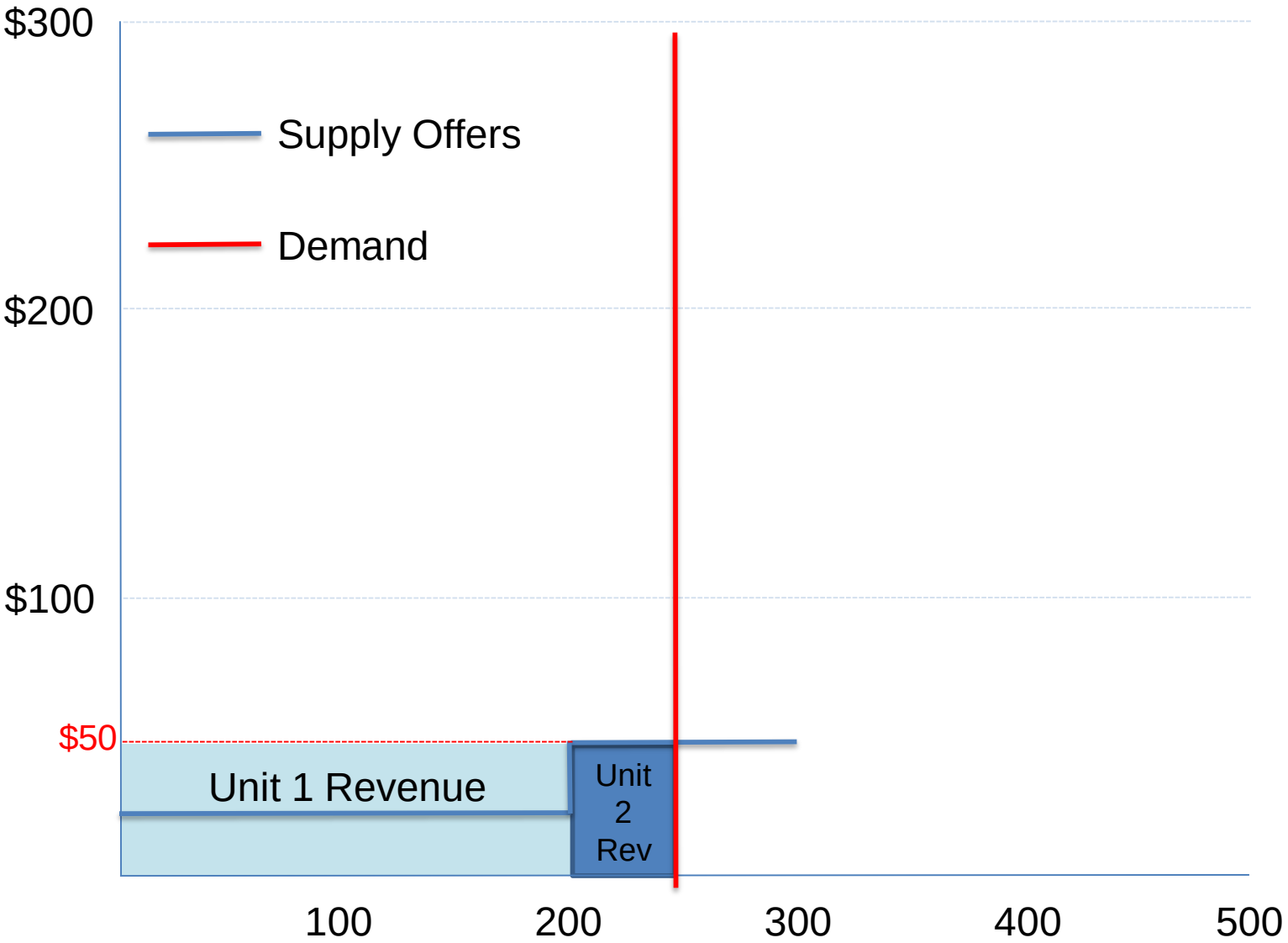
Example #1 – Both resources fully dispatchable

Example #1 – Both resources fully dispatchable Demand = 250MW

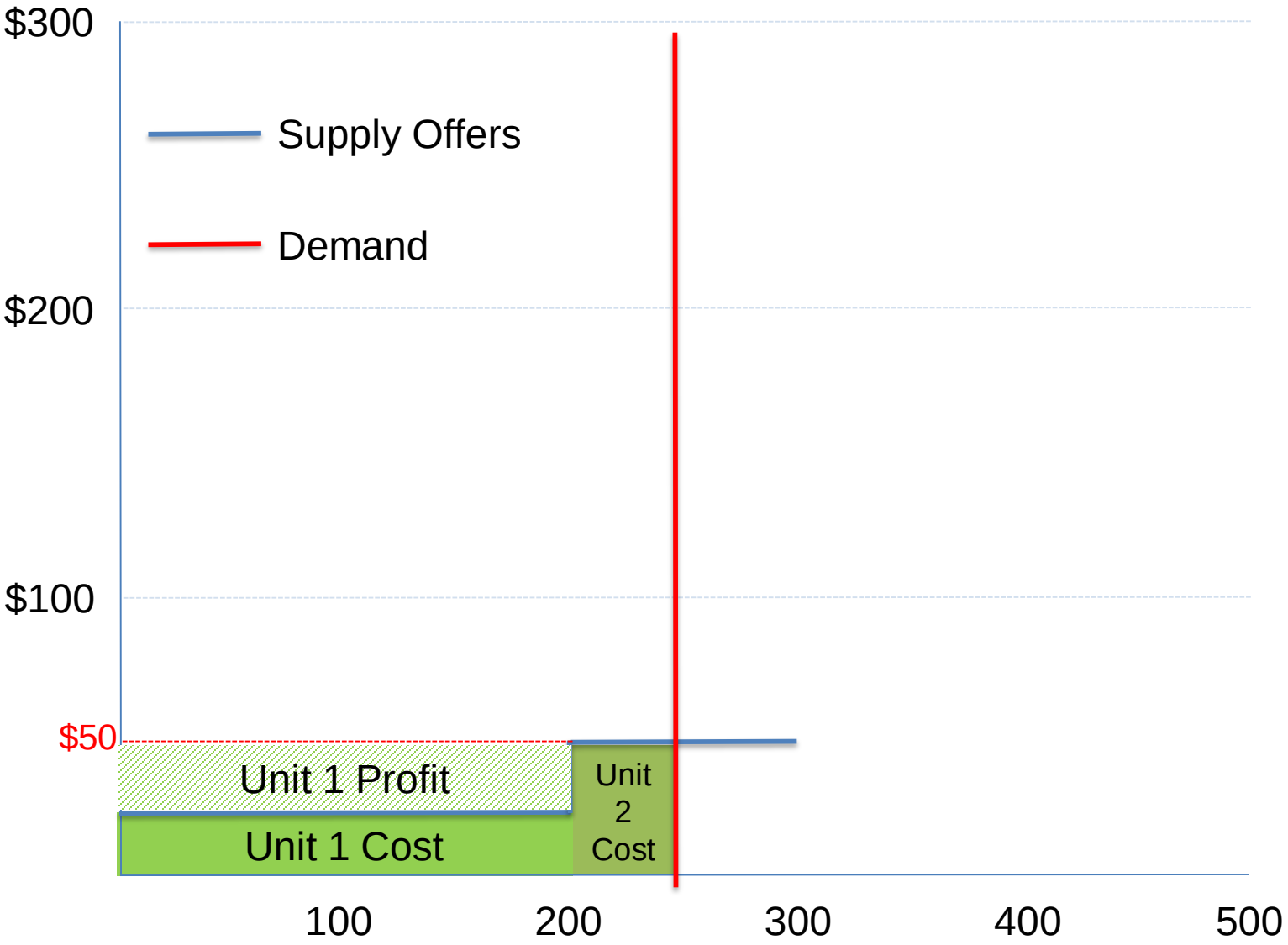
A	B	C	D	E	F	G
Unit	**Energy Award**	**Offer Price**	**Production Cost (B*C)**	**Market Price**	**Revenue (B*E)**	**Profit (F-D)**
1	200MW	$25	$5,000	$50	$10,000	$5,000
2	50MW	$50	$2,500	$50	$2,500	$0
	250MW		**$7,500**			

- Unit 1 earns profit being the infra-marginal resource
- Unit 2 earns no profit being the marginal resource

Example #1 – Both resources fully dispatchable



Example #1 – Both resources fully dispatchable

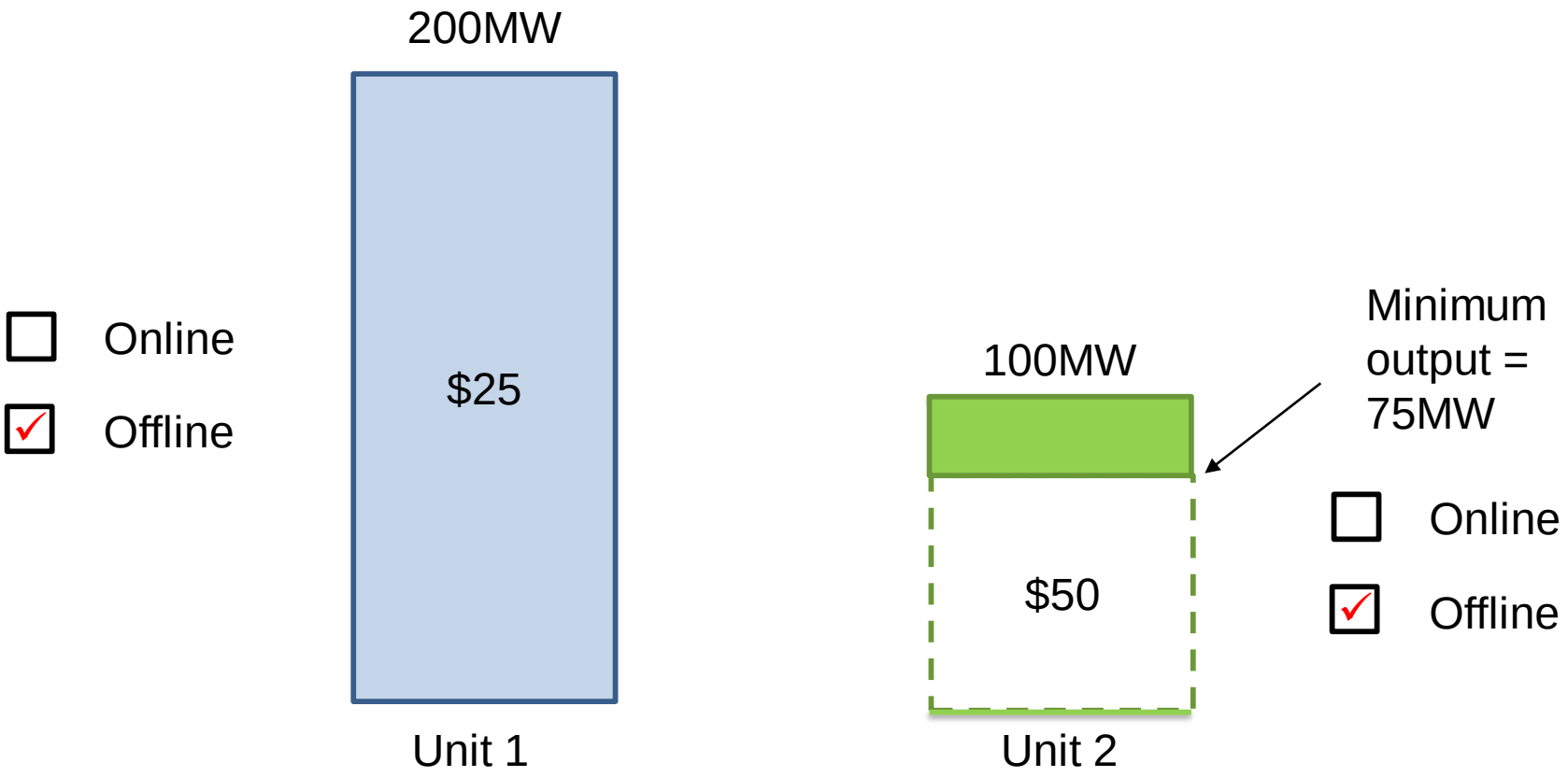


Why pay all resources the marginal cost instead of their offer cost?

- Under marginal cost pricing, sellers maximize their surplus by submitting offers that reflect their actual costs
  - Leads to efficient dispatch (selection of resources in merit order of lowest cost)
  - Incentive for sellers to bid their actual costs greatly facilitates market monitoring by permitting the bids of an entity that's exercising market power to be more readily distinguishable from the bidding strategy of an entity without market power that's just trying to maximize its revenue under pay-as-bid

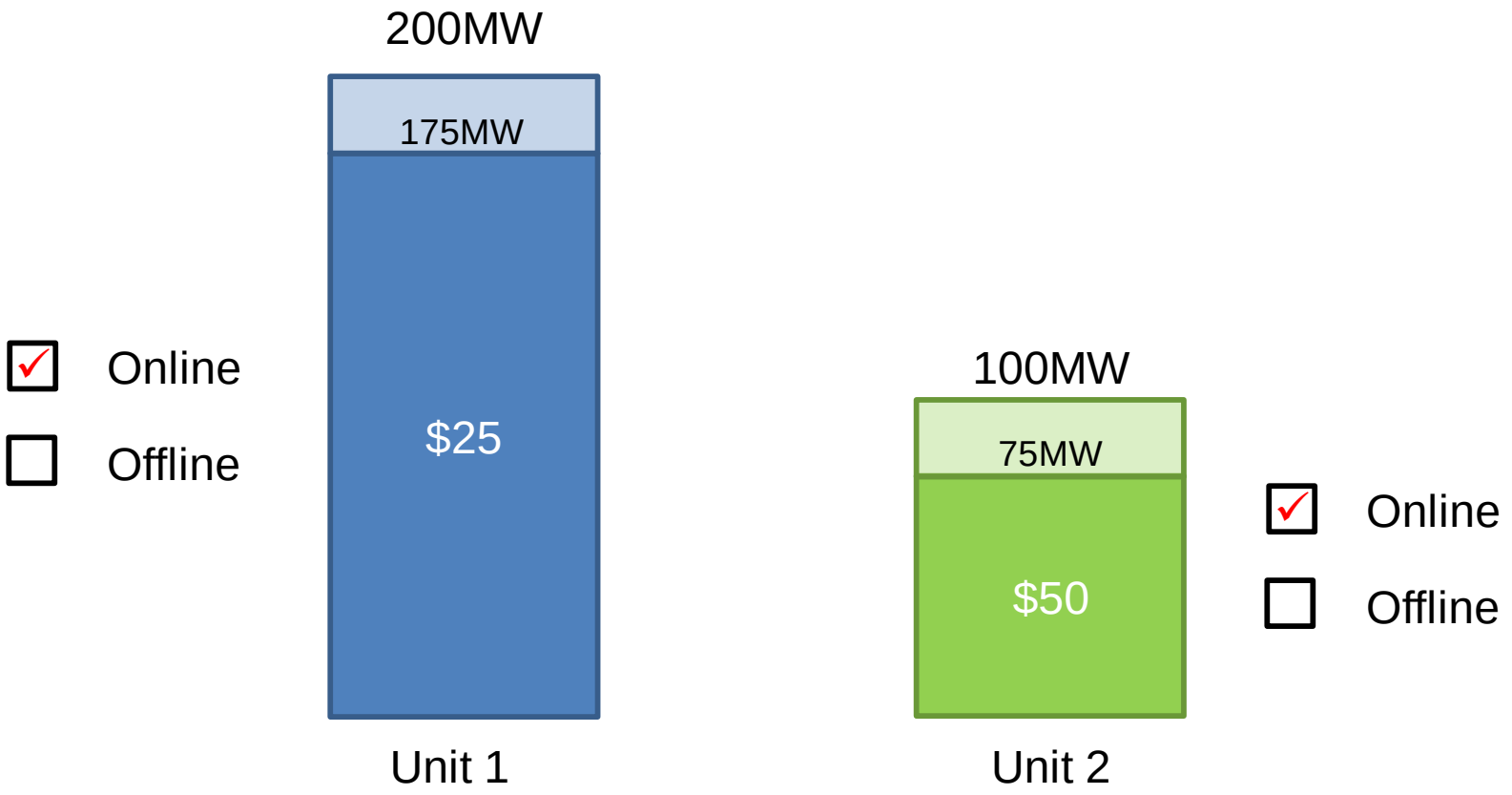
- In Example 1, Unit 1 would earn no surplus bidding actual costs under pay-as-bid pricing.
  - Unit 1 has incentive to markup its offers while still being selected in the dispatch.
  - Given imperfect information about competitors costs and the level of load the market will clear, small errors in the profit-maximizing pay-as-bid offer would lead to distortion of merit order and inefficient dispatch.

Example #2 – Unit 2 has min output
Demand = 250MW



How should we dispatch these units to serve 250MW of demand while minimizing production costs?

Example #2 – Unit 2 has min output
Demand = 250MW



Example #2 – Unit 2 has min output
Demand = 250MW

Unit	Energy Award	Offer Price	Production Cost
1	175MW	$25	$4,375
2	75MW	$50	$3,750
	250MW		**$8,125**

- What price does the market set in this example?
- How would you serve the next increment of demand and what would it cost?

Example #2 – Unit 2 has min output
Demand = 250MW

Unit	Energy Award	Offer Price	Production Cost
1	176MW	$25	$4,400
2	75MW	$50	$3,750
	251MW		**$8,150**

- The next increment of demand would be served by Unit 1 at an offer price of $25

- Therefore, the market price is set at $25
  - If market price was $50 would Unit 1 have incentive to follow its dispatch?

Example #2 – Unit 2 has min output

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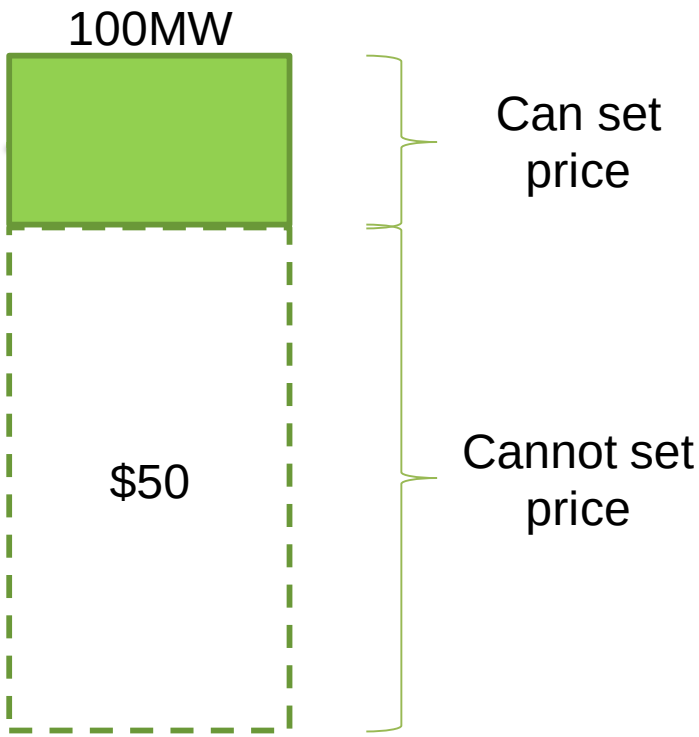
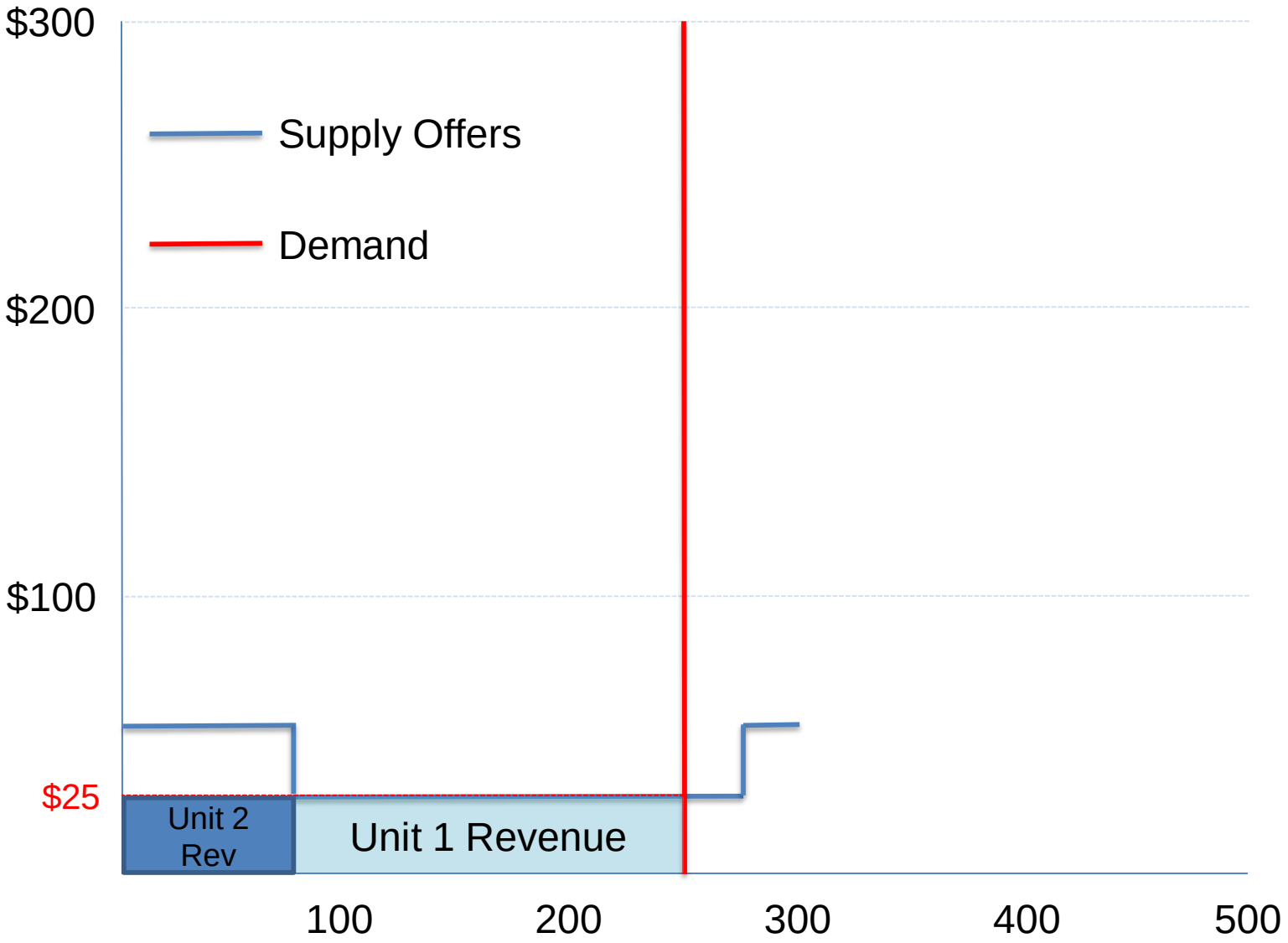


Example #2 – Unit 2 has min output
Demand = 250MW

A	B	C	D	E	F	G
Unit	**Energy Award**	**Offer Price**	**Production Cost (B*C)**	**Market Price**	**Revenue (B*E)**	**Profit (F-D)**
1	175MW	$25	$4,375	$25	$4,375	$0
2	75MW	$50	$3,750	$25	$1,875	$(1,875)
	250MW		**$8,125**			

- Unit 1 earns no profit being the marginal resource
- Unit 2 earns negative profit and requires an uplift payment to make it whole to its offer costs

Example #2 – Unit 2 has min output



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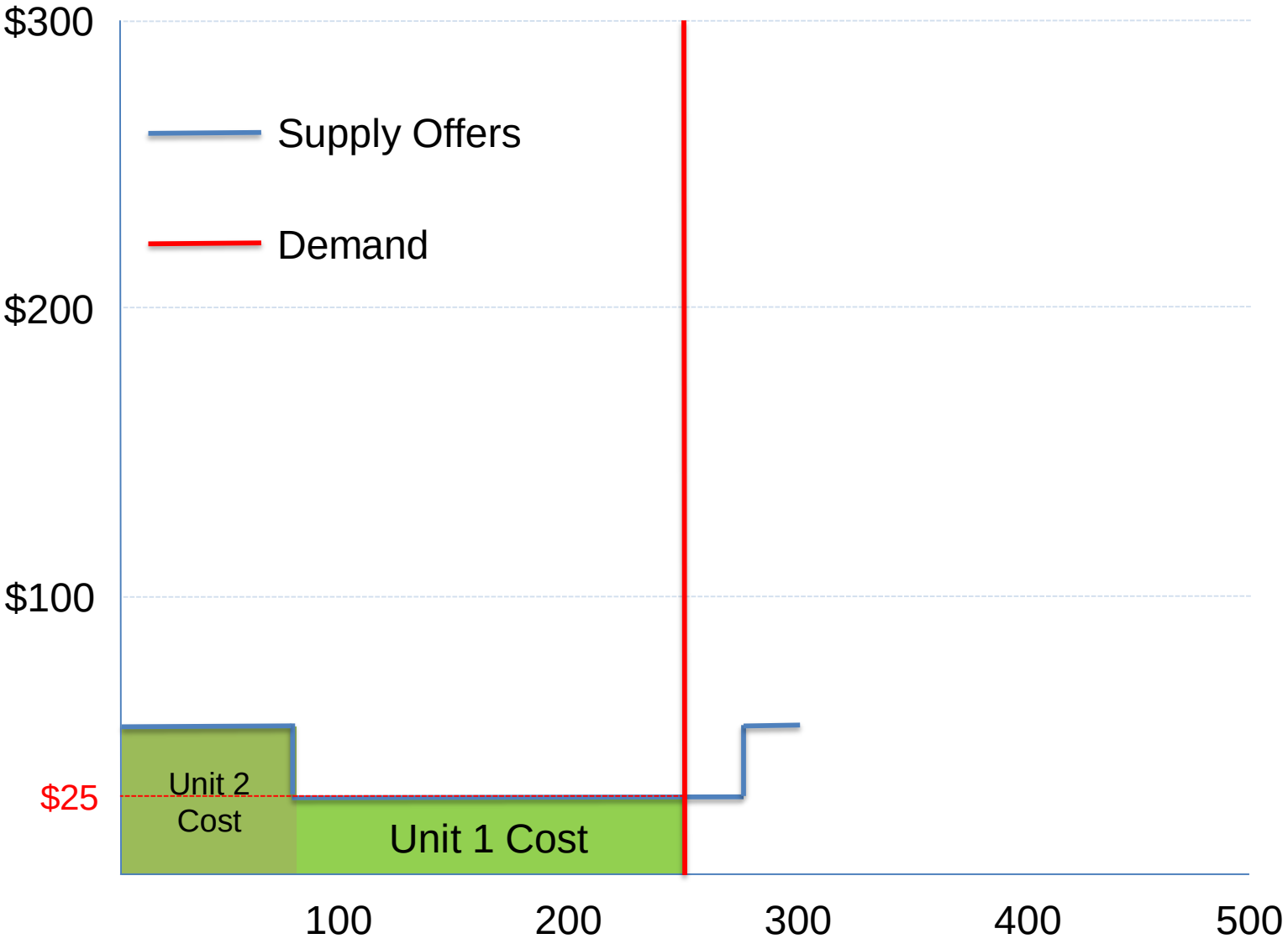

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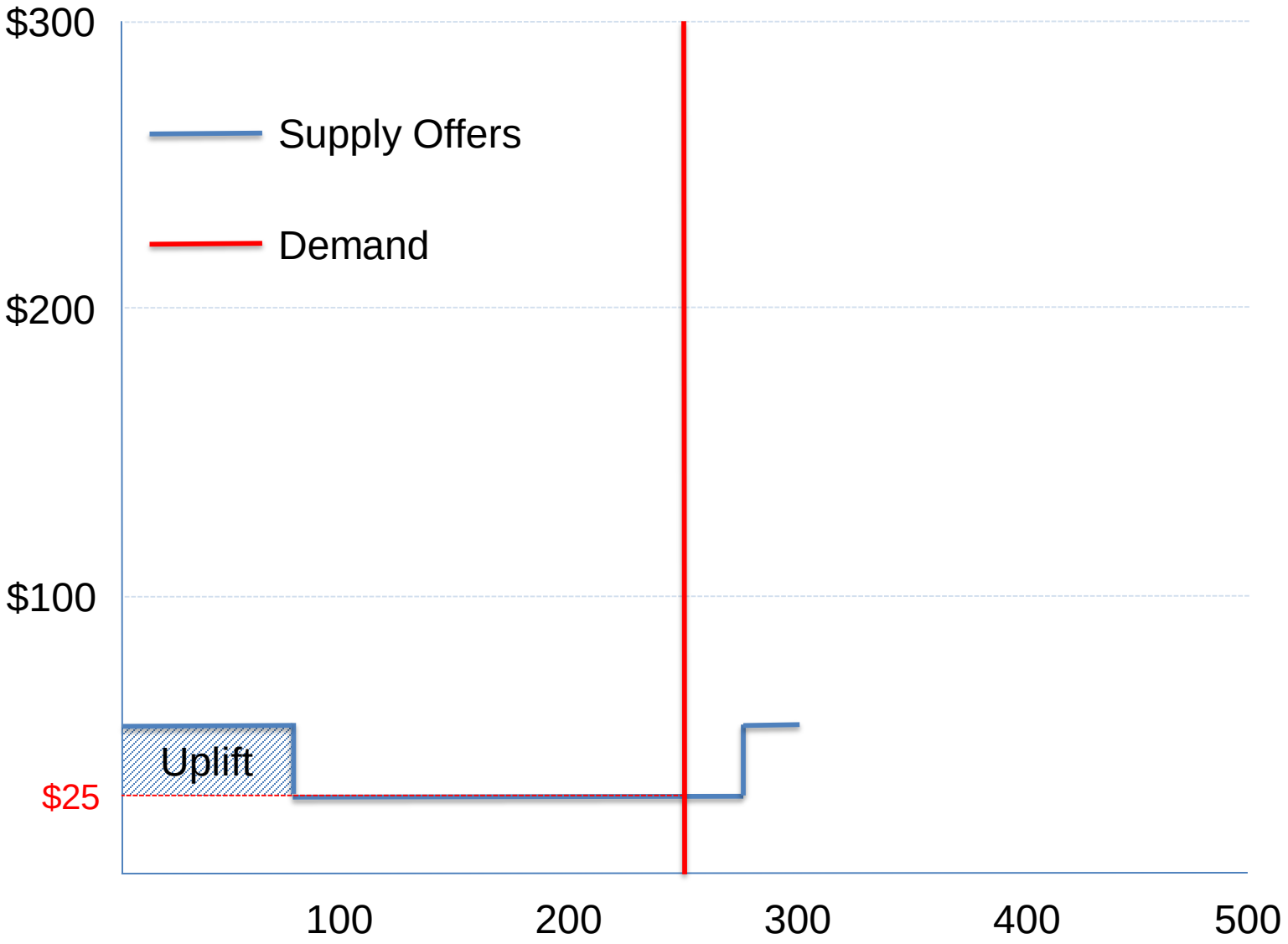
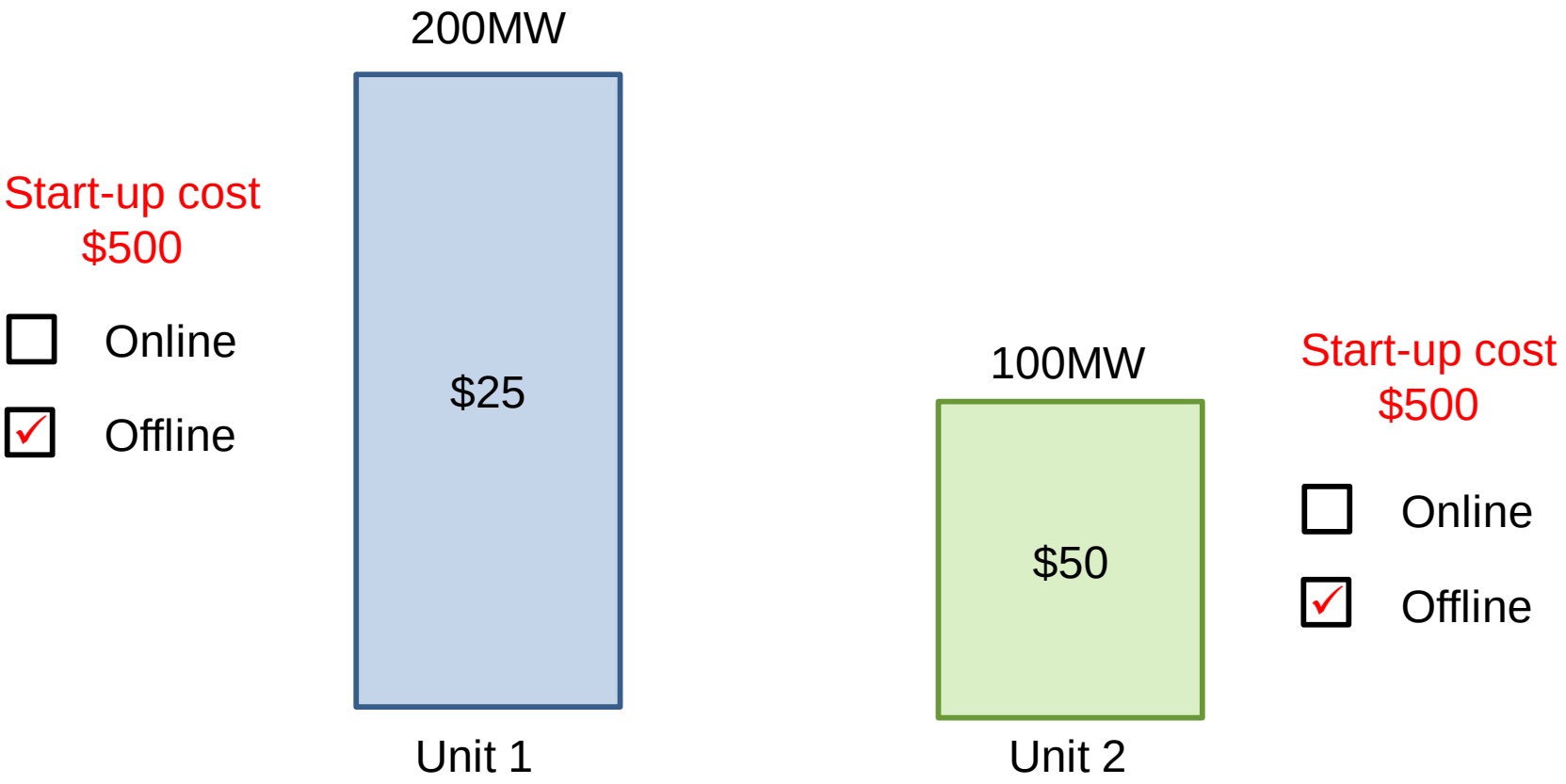


Example #3 – Unit 2 is dispatchable w/ fixed costs
Demand = 250MW



How should we dispatch these units to serve 250MW of demand while minimizing production costs?

Example #3 – Unit 2 is dispatchable w/ fixed costs
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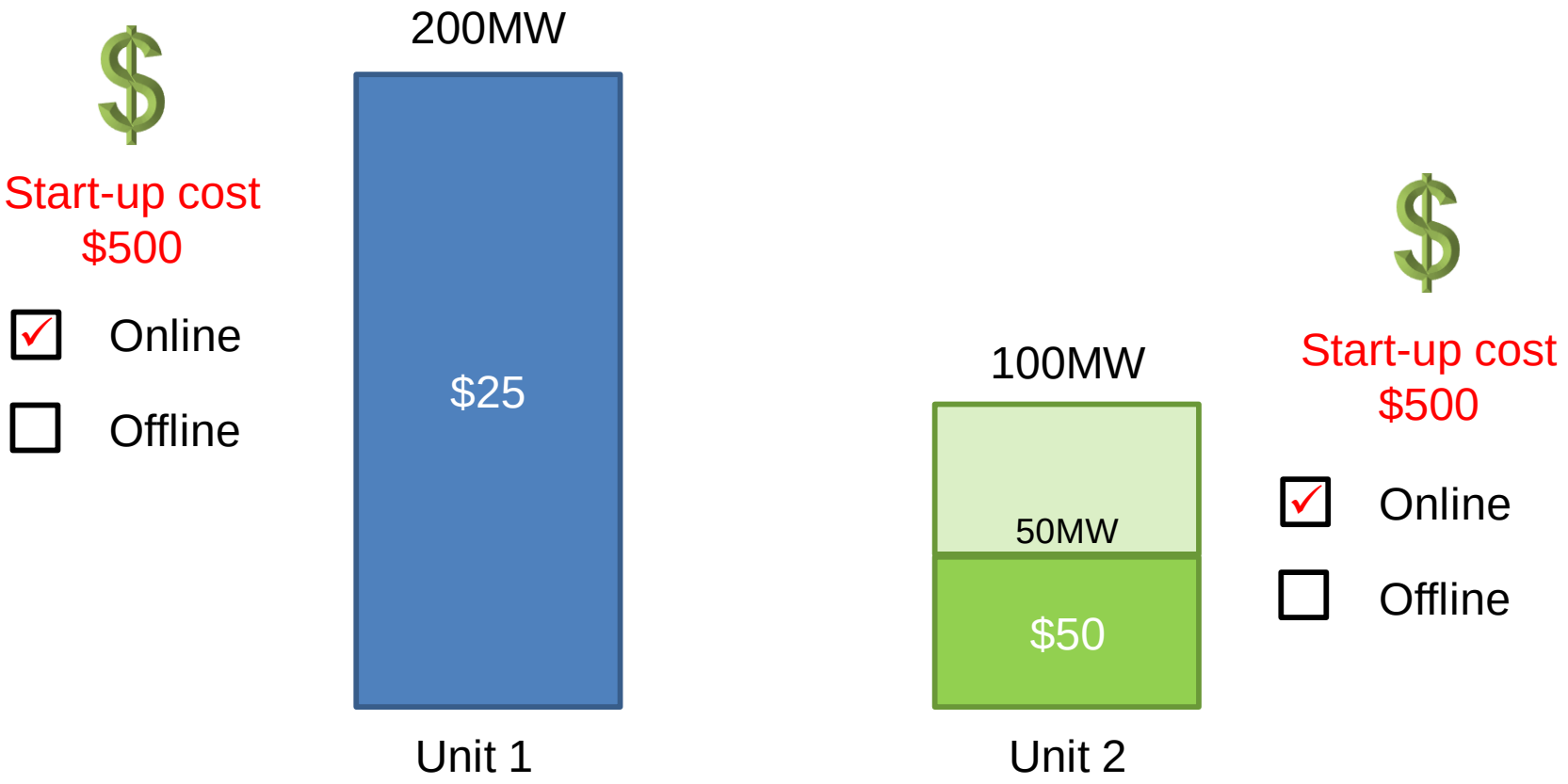


Example #3 – Unit 2 is dispatchable w/ fixed costs Demand = 250MW

Unit	Energy Award	Offer Price	Fixed Cost	Production Cost
1	200MW	$25	$500	$5,500
2	50MW	$50	$500	$3,000
	250MW			**$8,500**

- What price does the market set in this example?
- How would you serve the next increment of demand and what would it cost?

Example #3 – Unit 2 is dispatchable w/ fixed costs Demand = 250MW

Unit	Energy Award	Offer Price	Fixed Cost	Production Cost
1	200MW	$25	$500	$5,500
2	51MW	$50	$500	$3,050
	251MW			**$8,550**

- The next increment of demand would be served by Unit 2 at an offer price of $50
- Therefore, the market price is set at $50
- Unit 2s fixed cost does not affect the marginal cost and therefore does not affect the market price

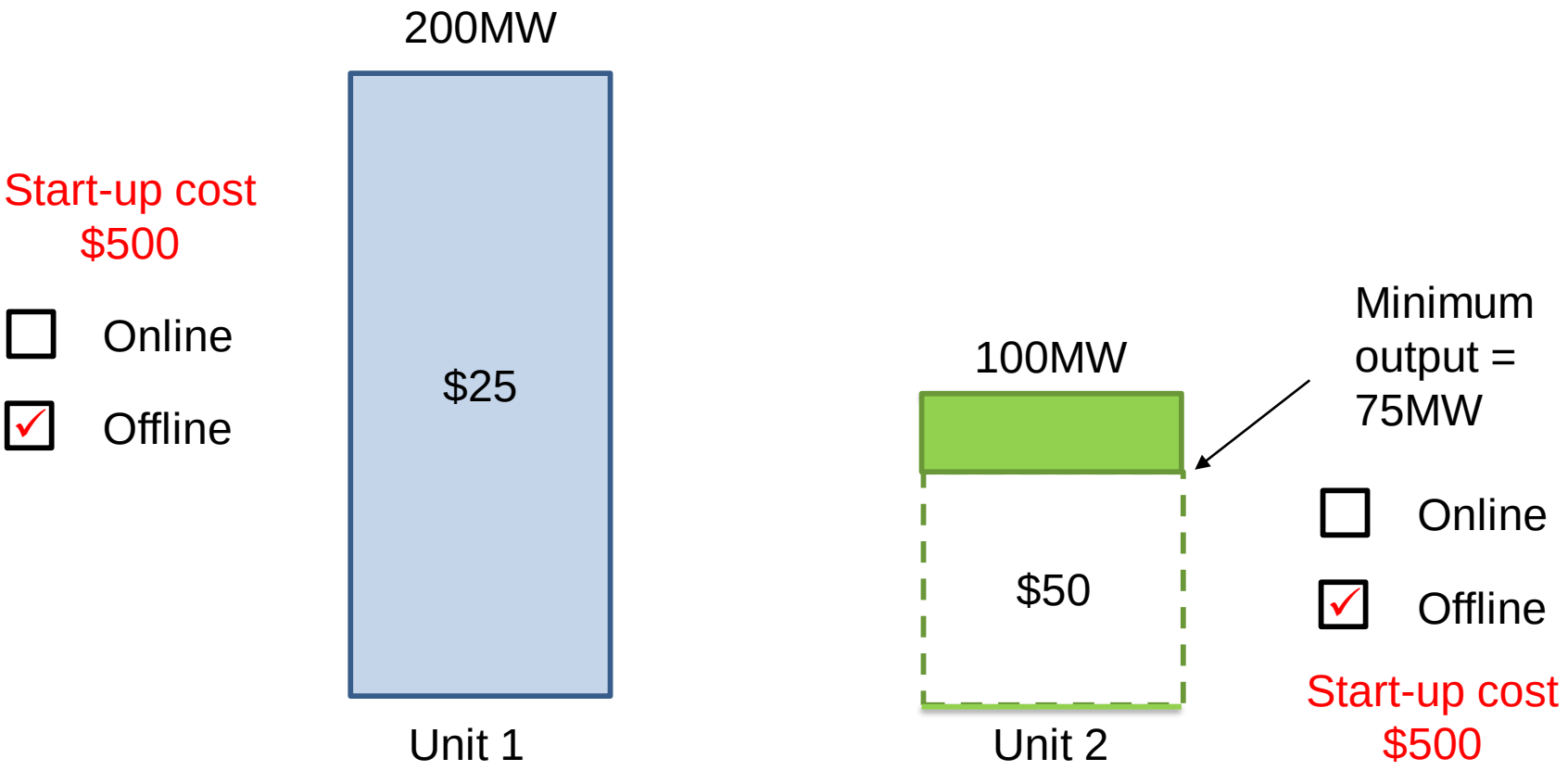
Example #3 – Unit 2 is dispatchable w/ fixed costs Demand = 250MW

A	B	C	D	E	F	G	H
Unit	**Energy Award**	**Offer Price**	**Fixed Cost**	**Production Cost ((B*C)+D)**	**Market Price**	**Revenue (B*F)**	**Profit (G-E)**
1	200MW	$25	$500	$5,500	$50	$10,000	$4,500
2	50MW	$50	$500	$3,000	$50	$2,500	$(500)
	250MW			**$8,500**			

- Unit 1 earns profit being the infra-marginal resource
  - Its market revenues are sufficient to cover its fixed costs

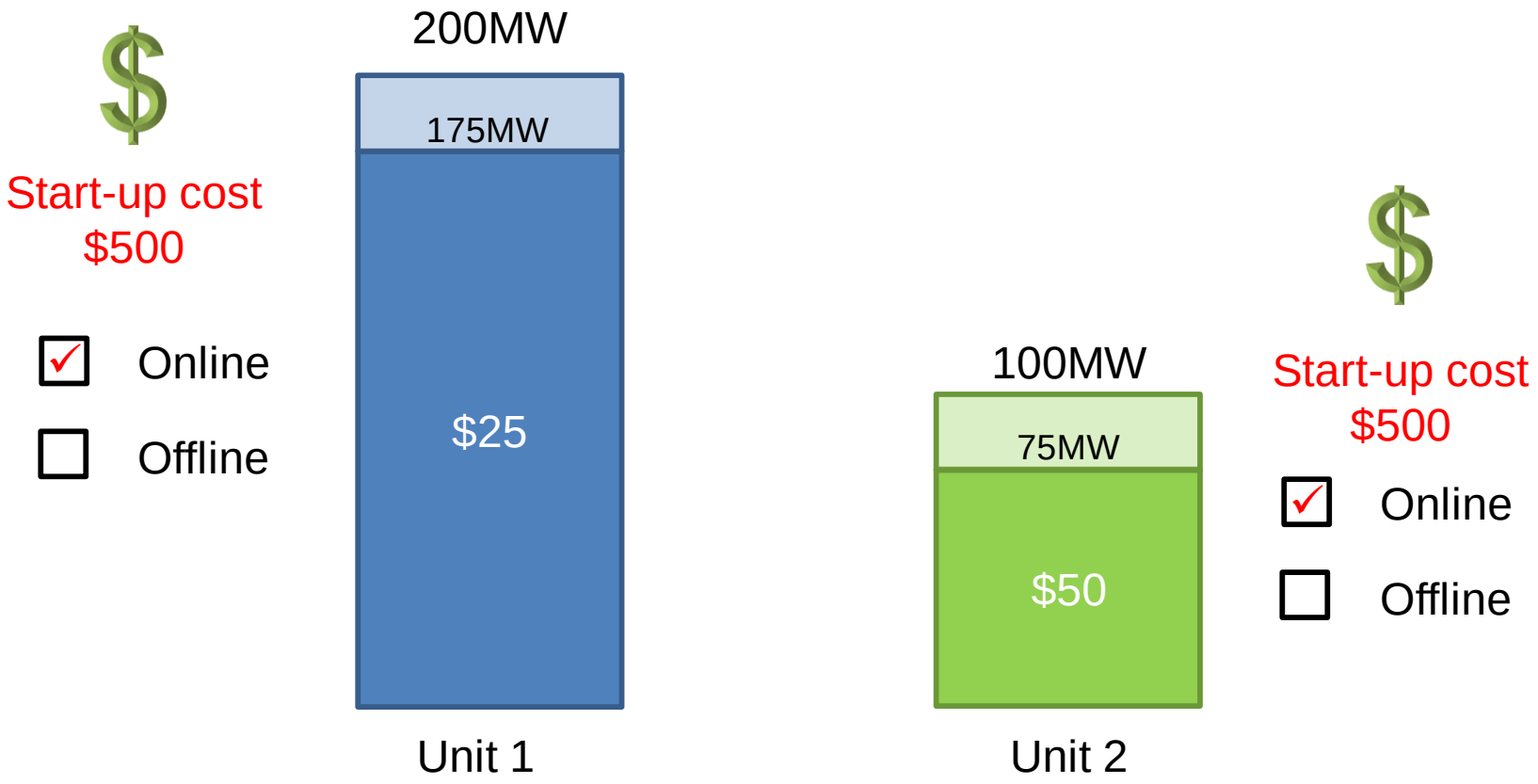
- Unit 2 earns no profit being the marginal resource
  - Its market revenues are insufficient to cover its fixed costs. The market would pay $500 of uplift.

Example #4 – Unit 2 is block-loaded w/ fixed costs
Demand = 250MW



How should we dispatch these units to serve 250MW of demand while minimizing production costs?

Example #4 – Unit 2 is block-loaded w/ fixed costs
Demand = 250MW



Example #4 – Unit 2 is block-loaded w/ fixed costs Demand = 250MW

Unit	Energy Award	Offer Price	Fixed Cost	Production Cost
1	175MW	$25	$500	$4,875
2	75MW	$50	$500	$4,250
	250MW			**$9,125**

- What price does the market set in this example?
- How would you serve the next increment of demand and what would it cost?

Example #4 – Unit 2 is block-loaded w/ fixed costs Demand = 250MW

Unit	Energy Award	Offer Price	Fixed Cost	Production Cost
1	176MW	$25	$500	$4,900
2	75MW	$50	$500	$4,250
	251MW			**$9,150**

- The next increment of demand would be served by Unit 1 at an offer price of $25
- Therefore, the market price is set at $25
- Unit 1s fixed cost does not affect the marginal cost and therefore does not affect the market price

Example #4 – Unit 2 is block-loaded w/ fixed costs Demand = 250MW

A	B	C	D	E	F	G	H
Unit	**Energy Award**	**Offer Price**	**Fixed Cost**	**Production Cost ((B*C)+D)**	**Market Price**	**Revenue (B*F)**	**Profit (G-E)**
1	175MW	$25	$500	$4,875	$25	$4,375	$(500)
2	75MW	$50	$500	$4,250	$25	$1,875	$(2,375)
	250MW			**$9,125**			

- Unit 1 market revenues are sufficient to cover its fixed costs. The market would pay $500 of uplift.

- Unit 2 market revenues are insufficient to cover its fixed costs. The market would pay $2,375 of uplift.

Workshop #2 planned topics

- Fast-start pricing features
- Fast-start pricing initial framework
- Fast-start pricing metrics