Wholesale Electricity Market Energy Price Formation

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Locational Marginal Prices Overview

- LMP definition: incremental cost to serve the next increment of demand at a particular location and time
  - LMP = [Marginal Cost of Energy] + [Marginal Cost of Transmission Congestion] + [Marginal Cost of Transmission Losses]
  - Mathematically: Partial derivative of objective value (production cost) divided by partial derivative of demand (solved through dual solution of economic dispatch problem, or shadow price of load balance constraint)
  - Numerator typically includes all locations and all times
  - Denominator includes the specific location and time being evaluated
- Locational granularity: Suppliers – nodal; demand – zonal
- Temporal granularity: Day-ahead – hourly; Real-time – 5-min
  - Real-time: Settled hourly in PJM, ISO-NE, MISO until FERC Order 825

Uplift and make-whole payments

- U.S. electricity markets include three part offers: incremental energy (per MWH), no load or minimum generation (per H) and startup cost (per start)
  – Traditional LMP only accounts for marginal resource's incremental energy cost
- ISO guarantees a resource following ISO directions to recover all bid-in operating costs
  – Mitigation and verification may be required for bid-in costs
- When the price for energy does not cover all costs, additional side payments (make-whole payments or revenue sufficiency guarantee) are paid to individual generators
- Typically happens to marginal resource and those with similar costs because no-load costs and start-up costs do not influence the energy price paid
- Often netted across day or commitment period
- Uplift usually allocated to loads, but sometimes to generators that deviate from schedule
- Additional uplifts also occur
  – Day-ahead profit assurance
  – Price volatility make-whole payment
  – Alternative fuel make-whole
  – Lost opportunity costs not provided through price

Seems Simple Enough, right?

So what’s the question?

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Price Formation Debate Example

Gen1: $20/MWh, Pmin=10, Pmax=100

Gen2: $100/MWh, NoLoadCost=$800/hour, Pmin=50, Pmax=80

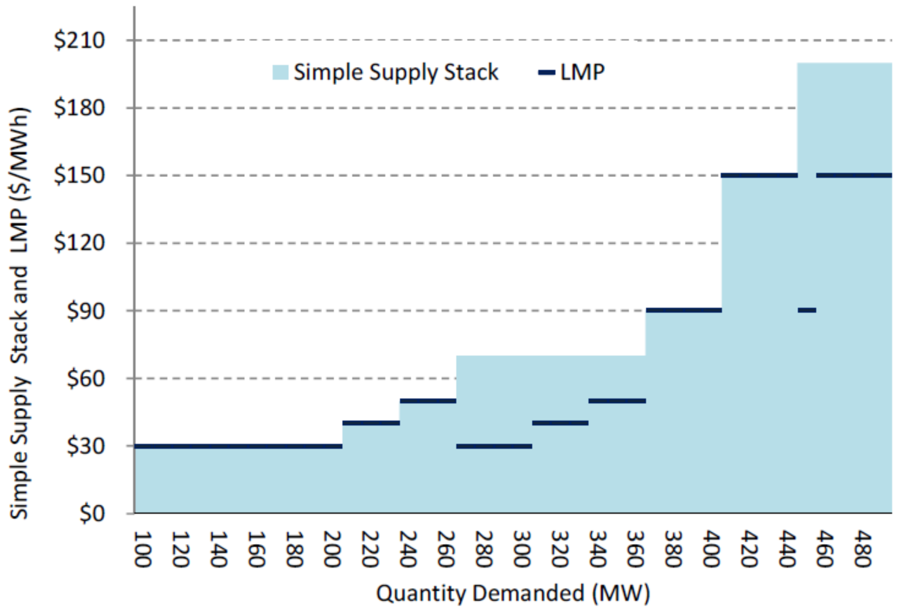
Demand = 120 MW

Optimal Solution

Gen1 P=100MW

Gen2 P=20MW

Figure 2
Example of LMP Pricing Mechanism



FERC, *Operator-initiated commitments in RTO and ISO Markets*, 2014

Price Formation Debate Example

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Gen2: $100/MWh, NoLoadCost=$800/hour, Pmin=50, Pmax=80

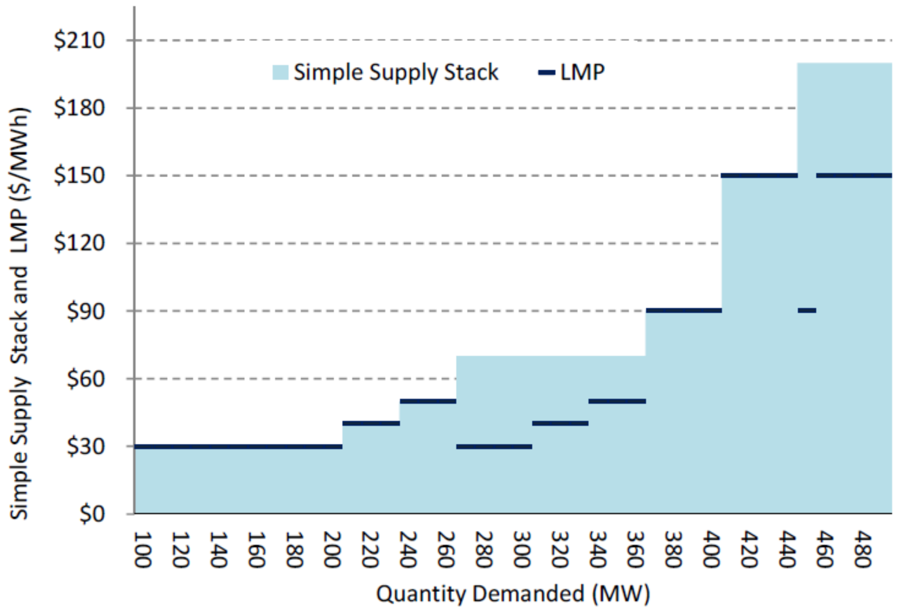
Demand = 120 MW

Optimal Solution

Gen1 P=100MW

Gen2 P=2~~0~~MW

Figure 2
Example of LMP Pricing Mechanism



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Price Formation Debate Example

Gen1: $20/MWh, Pmin=10, Pmax=100

Gen2: $100/MWh, NoLoadCost=$800/hour, Pmin=50, Pmax=80

Demand = 120 MW

Optimal Solution

Gen1 P=70MW

Gen2 P=50MW

What is the LMP?

$20/MWh? $100/MWh? $110/MWh?

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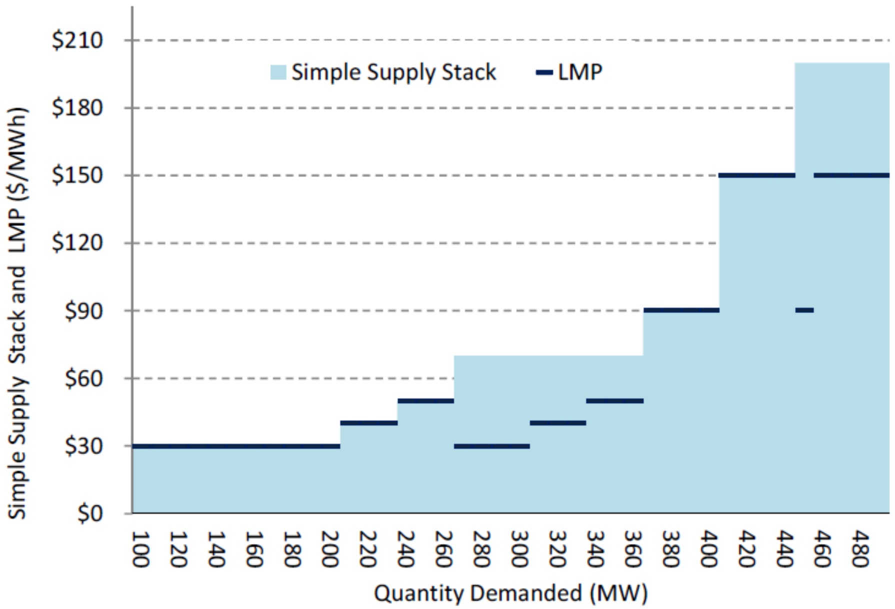
Example of LMP Pricing Mechanism



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Pricing with non-convexities: History

- NYISO and FERC, 2000
  - High cost block-loaded CTs in NYC were not able to set price and this led to depressed LMPs, reduced incentives for demand response, inappropriate price separation between NYC and rest of state, and poor investment signals
- MISO, ~2007-2009
  - Introduced concept of convex hull pricing (P. Gribik et al.), lengthy stakeholder process ensued
  - Extended LMP (ELMP) Phase I initiated in 2015, Phase II in 2017
- FERC NOPR 2016
  - Allow all fast-start units to set price, even when at minimum generation, incorporate start-up and no-load costs to price, and apply to day-ahead and real-time
- 2017: PJM Proposal to apply “fast start pricing” to all resources
- Dec. 2017: FERC ends broad fast start pricing NOPR, orders specific rules to NYISO, PJM, and SPP

Properties of "fast start pricing"

- Relaxation of minimum generation levels and for what resources
- Whether separation of pricing algorithm from scheduling algorithm exists
- Assurance that resources will stay on dispatch to ensure power balance when prices do not align with dispatch
- Incorporation of no-load/min-gen and start-up costs into pricing and for which resources
- Ability of offline resources to set the price in real-time market

Relaxation of minimum generation

Gen1: $20/MWh, Pmin=10, Pmax=100

Gen2: $100/MWh, NLCost=$800/hour, Pmin=0, Pmax=80

Demand = 120 MW

<u>Optimal Solution</u>

Gen1 P=70 MW

Gen2 P=50 MW

LMP=$20/MWh

<u>Relaxation</u>:

Gen1 P=100 MW

Gen2 P=20 MW

LMP = $100/MWh

Incorporation of No Load and Start-up Cost into prices

Gen1: \$20/MWh, Pmin=10, Pmax=100

New Gen2 Cost = \$100 + \$800/80 = \$110/MWh, Pmin=0, Pmax=80

An incremental amount of load has no impact on start-up cost or no load cost (commitment not part of pricing solution)

<u>Optimal Solution</u>

Gen1 P=70 MW

Gen2 P=50 MW

LMP=\$20/MWh

<u>Modified Solution</u>:

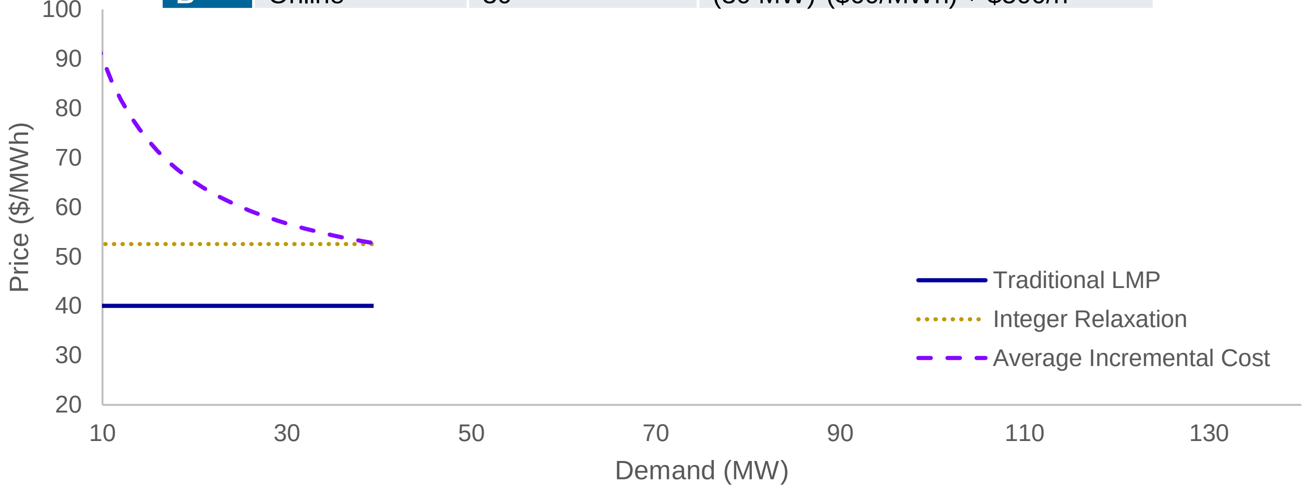
Gen1 P=100 MW

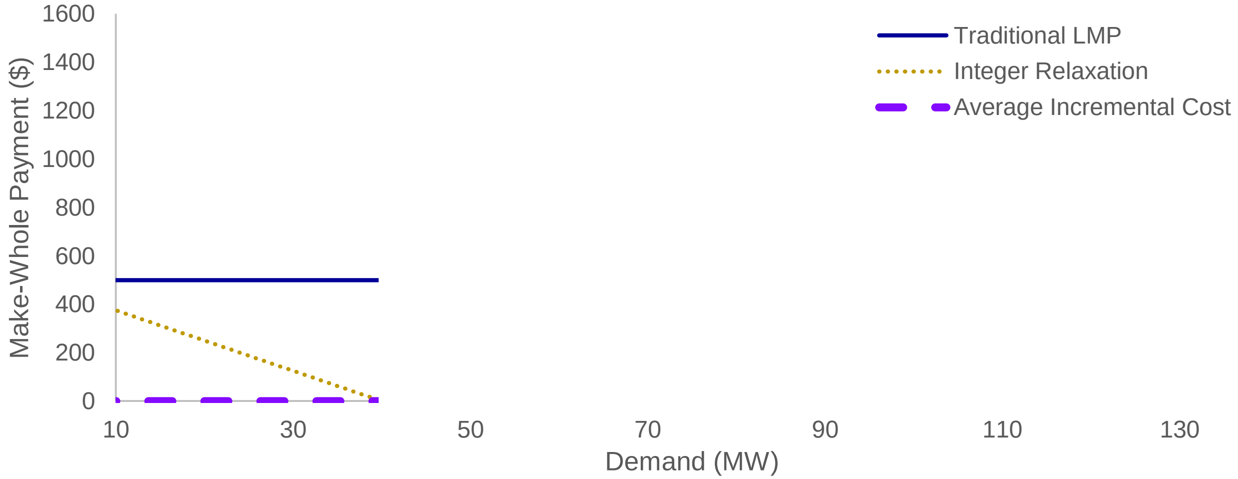
Gen2 P=20 MW

LMP = \$110/MWh

Price Comparisons

Gen	Commitment	Dispatch (MW)	Cost ($)
A	Online	40	(40 MW)*($40/MWh) + $500/h
B	Online	30	(30 MW)*($60/MWh) + $500/h





Traditional LMP: Historical way; the cost of meeting the next infinitesimally small increment of load

Integer Relaxation/Relaxed Minimum: Relax the variables in pricing run to account for non-convex costs and constraints (most existing and FERC direction)

Average incremental cost: Price equal to the total cost per MWH of marginal resource. No uplift (not used in practice anywhere)

Method	Price
Traditional LMP	C_g
Integer Relaxation* **Relaxed Minimum***	$C_g + \frac{C_g^{NL}}{P_g^{max}} + \frac{C_t^{SU}}{T^{MRT} P_g^{max}}$
Average Incremental Cost*	$C_g + \frac{C_g^{NL}}{p_{gt}^*} + \sum_t \frac{C_g^{SU}}{p_{gt}^*}$

Cg: Incremental energy cost
C^{NL}:No load cost; C^{SU}: Startup cost
P^{max}:Max capacity; T^{MRT}:Min run time
p^*: Operating level of marginal resource

Why does this matter and what are we doing about it?

- LMPs are made up (nonphysical) values – You can't plug in a voltmeter to an outlet and measure the LMP
  - Thus, we must create them in such a way to meet various objectives
- Different pricing methods may mean the difference between $0/MWh and not $0/MWh; >$1,000/MWh or much less
  - Different pricing logic can lead to different incentives
  - Can impact additional side payments or capacity payments
- EPRI facilitating ISO/RTO Price Formation Working Group
- NREL and EPRI just completed report on impact of price formation on revenue sufficiency on high renewable systems
- Continuing research with interested parties going forward into 2019
  - Administrative Shortage pricing levels
  - Intertemporal marginal resources and flexibility incentives
  - Incentives for reliability services, resilience attributes

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Summary on Resilience and Reliability Incentives

- Definition of resilience relative to reliability important
  - Supplier resilience (new definition): “the ability to harden supply resources, including associated fuel and all supply components against—and quickly recover from—high impact, low frequency (HILF) events.”
  - Supplier resilience one part of overall power system resilience– it may be the only type that is possible to incentivize through market structures in power-supply based markets
  - Transmission and distribution outages affect entire system regardless of fuel supply
  - Metrics (or calculation method for metrics) for reliability, resilience, and recovery and linkages across may need re-evaluation
- Existing mechanisms for incentivizing supplier resilience across markets
  - Capacity Performance (PJM, ISO-NE)
  - Min oil / Dual Fuel Constraints and Cost Recovery (NYISO)
  - Reserve and Transmission Shortage Pricing (all ISOs)
  - Emergency Pricing Procedure (MISO) and Scarcity Pricing (NYISO)
- Potential enhancements
  - Consider externally driven events, vulnerabilities from supply fleet, and common mode in resource adequacy calculation
  - Shortage pricing during T&D outages to incentivize local supply
  - Evaluate which reliability services not compensated
  - Price separation for fuel security when applicable
  - Can resilience simply be “keep doing what you’re doing, but make sure to include events beyond faults and ‘typical’ generator outages in your calculations”?

ISO/RTO Price Formation Comparisons

Characteristic	ISO-NE	CAISO	NYISO	MISO	PJM
Separation of scheduling & pricing	Separate	Integrated	Separate	Separate	Integrated
Length of RTM horizon	Single 15-minute ahead	Multiple, 13 intervals, 1-hour ahead	Multiple, 5 intervals, 1-hour-ahead	Single, 10-minute ahead	Single, 10-minute ahead
Set of resources with alternative pricing applied	30-min start-up resource	Online registered Constrained Output Generators (block-loaded)	Block-loaded resources	60-min start-up resources (ELMP Ph. II) includes DR	Block loaded resources
Minimum Output	Relaxed to zero	Relaxed to zero	Relaxed to zero	Relaxed to zero	Relaxed to 80%
Commitment Cost	No load and start-up cost amortized over Pmax	Min gen cost amortized over Pmax	Start-up and min gen cost amortized only for offline resources	No load and start-up cost incorporated into price based on “unit status”	None
Incentive to stay on dispatch	Provide lost opportunity cost	Penalties for poor performance	Penalties for poor performance	Penalties for poor performance	No lack of incentive. ACE corrected through regulation
Offline resources			Yes, if 10-min startup	Yes, if relieving transmission/ reserve shortage condition	

Notes

CAISO: There are currently no resources that have opted to be designed as Constrained Output Generators (COG)

MISO/ISO-NE: resources that have pricing logic applied also must have minimum online times that are 1 hour or less.

ERCOT: Minimum generation relaxation allowed as manual process for fast start resources, who are allowed to bid fixed operating costs

SPP: allow “enhanced energy offers” including SU/NL costs but impacts physical dispatch; min-gen relaxation to physical not pricing

IESO, AESO: Generally, no special pricing logic

Parallel Pricing and Scheduling Runs

Gen1: $20/MWh, Pmin=10, Pmax=100

Gen2: $100/MWh, NLCost=$800/hour, Pmin=0, Pmax=80

Demand = 120 MW

Optimal Solution	Relaxation:
Gen1 P=70 MW	Gen1 P=100 MW
Gen2 P=50 MW	Gen2 P=20 MW
LMP=$20/MWh	LMP = $100/MWh

ACE = +30MW!

Parallel Pricing and Scheduling Runs

Gen1: $20/MWh, Pmin=10, Pmax=100

Gen2: $100/MWh, NLCost=$800/hour, Pmin=0, Pmax=80

Demand = 120 MW

Provide Schedules from Physical Run and Prices from Pricing Run

Optimal Solution	Relaxation:
Gen1 P=70 MW	Gen1 P=100 MW
Gen2 P=50 MW	Gen2 P=20 MW
LMP=$20/MWh	LMP = $100/MWh

ACE = 0MW

Assurance of low cost resources following schedule

Gen1: $20/MWh, Pmin=10, Pmax=100

Gen2: $100/MWh, NLCost=$800/hour, Pmin=0, Pmax=80

Demand = 120 MW

Option 1: Penalize for deviation

Gen1 Profit: $5600

Optimal Solution

Gen1 P=70 MW

Gen2 P=50 MW

LMP=$20/MWh

Option 2: Provide $2400 Opportunity Cost

Gen1 Possible Profit: $8000

Relaxation:

Gen1 P=100 MW

Gen2 P=20 MW

LMP = $100/MWh

Recent FERC Orders

- NYISO
  - Apply pricing logic to all fast start resources rather than "block loaded" resources
  - Include commitment costs, for resources
- PJM
  - Relax minimum generation 0 rather than 90%
  - Allow all fast start resources to set price and incorporate commitment costs
  - Fast start should be less than 1 hour start-up time
  - Include logic in market services tariff
- SPP
  - Adjust scheduling and dispatch to be more consistent with least cost dispatch
  - Relaxing of minimum generation for pricing and incorporate commitment costs
  - Apply to all fast start even those that don't register as quick start
  - Include logic in market services tariff

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