Energy Market

Electric energy[1] is *"the generation or use of electric power over a specified time, usually expressed in gigawatt-hours (GWh), megawatt-hours (MWh), or kilowatt-hours (kWh)."*[2] An electric energy market is a "*system for purchasing and selling electric energy using supply and demand to set the price.*"[2] It is a part of an electricity market and is coordinated by an Independent System Operator (ISO) or a Regional Transmission Organization (RTO). The energy market is used in a restructured electric industry where the electric power generating facilities and services are separated from the power transmission and distribution lines and services to provide more energy-efficient energy production. In the restructured industry, generating companies are competing to sell the energy, allowing a consumer to choose his or her own electricity suppliers.

An energy market is different than any other economic market. First, electrical energy cannot be stored in large quantities. It must be produced in real-time to meet a constantly changing demand. Second, electric energy cannot be labeled or traced out to sources or sinks. Once energy is produced, whether by a coal power plant or a renewable power plant, it cannot be distinguished. Third, power flows cannot be controlled by contracts because power flows follow the laws of physics. These differences make an energy market very challenging to operate.

An energy market can have one of three architectures:

- Poolco model – a spot market where generating companies compete for the right to supply energy and consumers compete for the right to consume energy. In the poolco model, supply and consumption go directly to and from the grid, instead of to a specific consumer and from a specific generating company
- Bilateral contracts – trading contracts between a specific generating company (a seller) and a consumer (a buyer) without going through a spot market
- Hybrid model – a combination of the poolco model and the bilateral contracts

Today's markets are mostly hybrid models where an ISO/RTO is coordinating the spot market and is acting as a clearinghouse for the bilateral contracts.

Market Clearing

The energy market is a two-sided auction model. Generating companies submit bids and consumers submit offers to the ISO/RTO. The generating companies submit bids to supply a certain amount of electrical energy at a certain price, while the consumers submit offers to consume a certain amount of electrical energy at a certain price. The ISO/RTO aggregates the bids in a supply curve and the offers in a demand curve. The intersection of the aggregated demand and supply curves represents the market clearing price (MCP) and the market clearing quantity (MCQ). If the generating company's bid is less than the MCP, it will be accepted. Conversely, if a consumer's offer is larger than the MCP, it will be accepted. The generating companies will be informed by the ISO/RTO how much they should generate; consumers will be informed how much they are allowed to draw from the grid. The market clearing mechanism can be illustrated using a simple example with two generating companies and two consumers.

Example 1 – Market Clearing: An ISO/RTO receives the bids and offers, for a particular hour, from two producers and two consumers as shown in Exhibit 1 and Exhibit 2, respectively. Gen Company 1 is willing to sell 200 MWh at $10/MWh, an additional 50 MWh at $25/MWh, an additional 50 MWh at

[1] Many of the technical terms used in this primer are defined in a companion *Glossary for Power Market Primers.*
[2] ISO New England. (2012). *Glossary and Acronyms.* Retrieved on January 5, 2012, from http://www.iso-ne.com/support/training/glossary/index-p2.html

$40/MWh, and an additional 50 MWh at $60/MWh. Gen Company 2 is willing to sell 150 MWh at $15/MWh, an additional 100 MWh at $20/MWh, and an additional 50 MWh at $50/MWh.

Exhibit 1 Generating company bids

Gen Company 1	
Price [$/MWh]	Quantity [MWh]
10	200
25	50
40	50
60	50

Gen Company 2	
Price [$/MWh]	Quantity [MWh]
15	150
20	100
50	50

Similarly, Consumer 1 is willing to buy 50 MWh at $60/MWh, an additional 50 MWh at $50/MWh, and an additional 100 MWh at $30/MWh. Consumer 2 is willing to buy 50 MWh at $80/MWh, an additional 75 MWh at $70/MWh, an additional 150 MWh at $40/MWh, and an additional 200 MWh at $20/MWh.

Exhibit 2 Consumer offers

Consumer 1	
Price [$/MWh]	Quantity [MWh]
60	50
50	50
30	100

Consumer 2	
Price [$/MWh]	Quantity [MWh]
80	50
70	75
40	150
20	200

In order to clear the market, the ISO/RTO determines the aggregated supply and demand curves by stacking up the bids and offers (Exhibit 3).

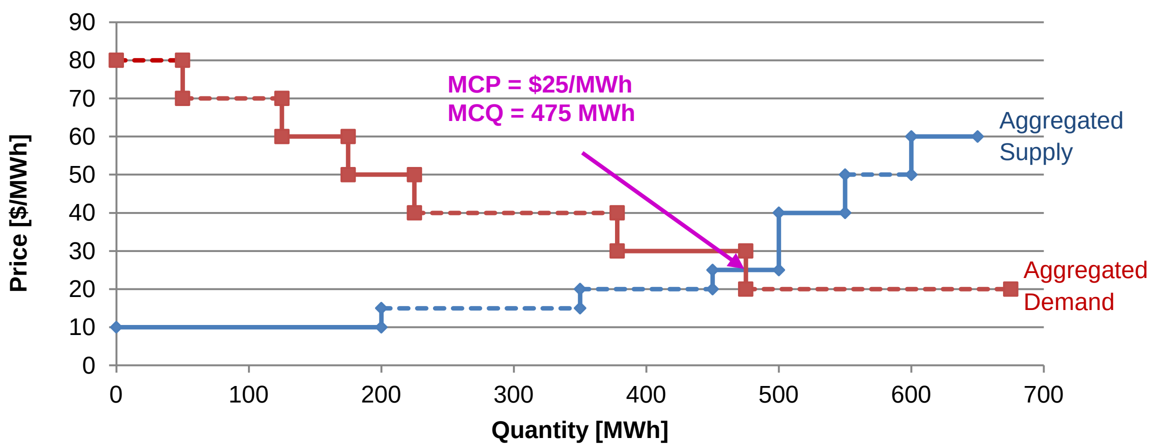
Exhibit 3 Aggregated supply and demand curves

Aggregated Supply		
Price [$/MWh]	Quantity [MWh]	Gen Company
10	0-200	1
15	200-350	2
20	350-450	2
25	450-500	1
40	500-550	1
50	550-600	2
60	600-650	1

Aggregated Demand		
Price [$/MWh]	Quantity [MWh]	Consumer
80	0-50	2
70	50-125	2
60	125-175	1
50	175-225	1
40	225-375	2
30	375-475	1
20	475-675	2

The supply and demand curves are depicted in Exhibit 4. The intersection of these two curves represents the MCP and the MCQ. All bids and offers shown to the left of the MCQ will be accepted.

Exhibit 4 Market clearing price and quantity



For the particular hour, the MCP will be set to $25/MWh and the total traded energy will be 475 MWh. All participants receive/pay the same MCP because the transmission network was not included in the analysis. Gen Company 1 will sell to the grid 225 MWh, with revenue of $5,625. Gen Company 2 will sell 250 MWh, with revenue of $6,250. Consumer 1 will draw from the grid 200 MWh, with an expense of $5,000. Consumer 2 will draw 275 MWh, with an expense of $6,875. The total revenue is equal to the total expenses, if the transmission network is not included in the analysis, or if there is no network congestion.

An ISO/RTO dispatches generators in a merit order, meaning that it starts from the least expensive units and moves up to more expensive units. However, sometimes this is not possible due to power delivery limitations or power constraints of the transmission system. In this case, more expensive generators that have no transmission system limits may be operated in place of the less expensive units. This is referred to as "out of merit dispatch."

Locational Marginal Price

Locational marginal price (LMP) is a pricing mechanism used by an ISO/RTO to price energy purchases and sales, to price transmission congestion cost, and to price the cost of energy losses. LMP is defined as a cost to serve the next MW of load at a specific location, using the lowest production cost of all available generators and with respect to all transmission limits.[3] LMP is based on actual (physical) energy flows within an ISO/RTO, not on contract paths. Example 2[4] is used to illustrate the LMP pricing mechanism.

Example 2 – Locational Marginal Price: An ISO/RTO receives the bids and offers, for a particular hour, from two producers and two consumers, shown in Exhibit 5. Gen Company 1 and Consumer 1 are located in Area 1, and Gen Company 2 and Consumer 2 are located in Area 2. Area 1 and Area 2 are connected with a transmission line with a power limit of 500 MW. Gen Company 1 is willing to sell 500 MWh at $25/MWh and Gen Company 2 is willing to sell 250 MWh at $35/MWh. Consumer 1 is willing to buy 200 MWh and Consumer 2 is willing to buy 275 MW, regardless of the electricity price. Using the same approach illustrated in Example 1, the ISO/RTO set the MCP to $25/MWh and energy traded at 475 MWh.

Exhibit 5 Simple electric energy system without congestion

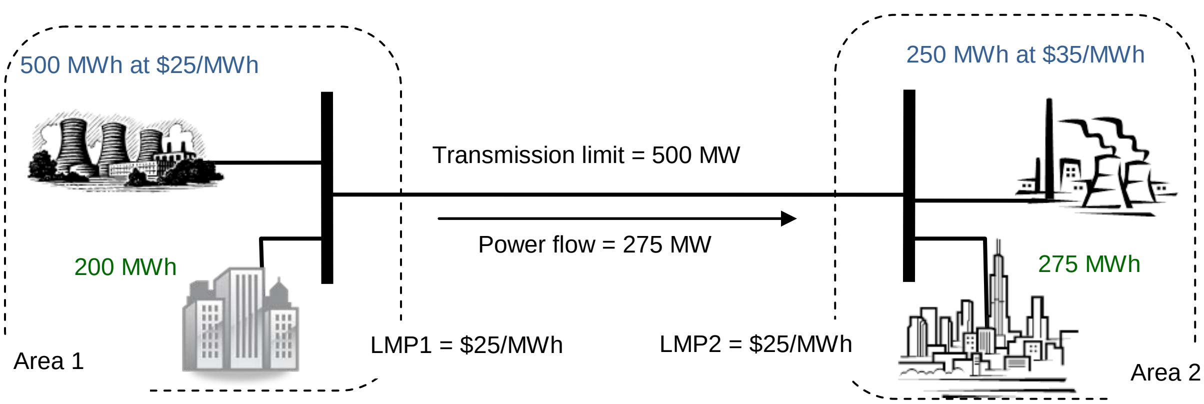


Image created by NETL.

[3] New York ISO. (2011). *Glossary: Locational Marginal Price*. Retrieved on December 28, 2011, from http://www.nyiso.com/public/markets_operations/services/customer_support/glossary/index.jsp

[4] Example 1 may also be used to illustrate LMP; however, due to the complexity to obtain the optimal solution for a transmission congestion problem, Example 1 is replaced with a simpler example that illustrates LMP more intuitively. Solving a transmission congestion problem in Example 1 requires using an optimization solver and is beyond the scope of this primer.

Gen Company 1 meets all demand and sells to the grid 475 MWh at $25/MWh. Consumer 1 draws 200 MWh from the grid and pays $25/MWh, while Consumer 2 draws 275 MWh and pays $25/MWh. Power flow over the transmission line is 275 MW from Area 1 to Area 2. The generating companies' total revenues ($11,875) are equal to the total consumers' payments ($11,875) because there is no congestion in the system. The ISO/RTO used the cheapest generation company to provide energy for both demands.

Assuming the transmission line has a power limit of 250 MW (Exhibit 6), the ISO/RTO will not be able to schedule the cheapest resources first. The maximum power that can be transferred from Area 1 to Area 2 is constrained to 250 MW. Because of the fully-loaded transmission line, an additional MW of load in Area 1 is provided by Gen Company 1 at $25/MWh and an additional MW of load in Area 2 is provided by Gen Company 2 at $35/MWh. The marginal production cost is therefore different in each area. Because the marginal price depends on the location where the energy is produced or consumed, it is called "locational marginal price." LMP for Area 1 is set to $25/MWh and LMP for Area 2 is set to $35/MWh.

Exhibit 6 Simple electric energy system with congestion

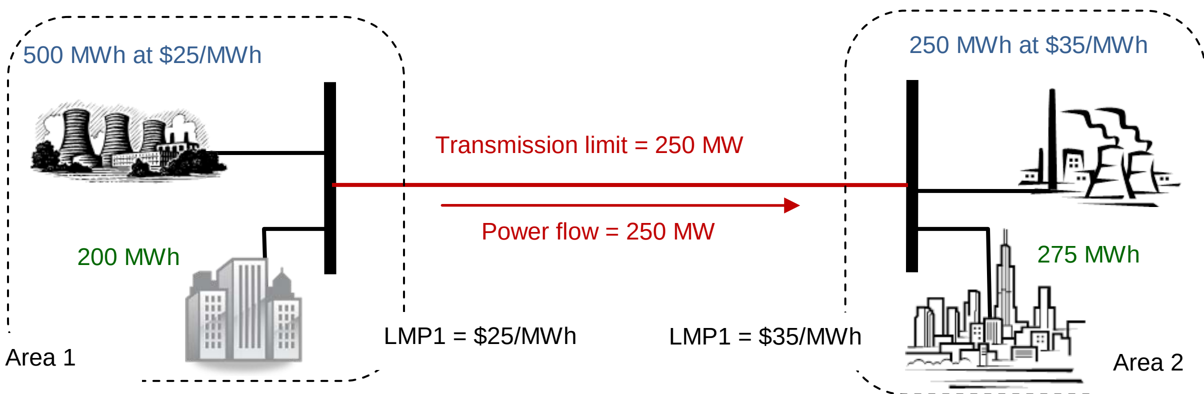


Image created by NETL.

Gen Company 1 produces 450 MWh and is paid $25/MWh. Gen Company 2 produces 25 MW and is paid $35/MWh. Consumer 1 buys 200 MWh at $25/MWh. If this was a bilateral market, Consumer 2 would buy 250 MWh at $25/MWh and 25 MWh at $35/MWh; however, Consumer 2 buys all 275MWh at $35/MWh because Consumer 2 is in a pool market. The total generators' revenue ($12,125) is not equal to the total consumers' payment ($14,625), because the congested transmission limited the use of cheaper generating resources. In this case the consumers pay more than the generating units receive. The excess is the congestion cost. The congestion costs are collected by the market operator and are given to holders of a financial transmission right (FTR) as a compensation for transmission congestion charges that arise when the transmission grid is congested. More details about FTR can be found in the *Financial Transmission Rights* primer.

Congestion Cost (Congestion Surplus)

The congestion costs are approximately[5] equal to a difference in LMP prices across the transmission line multiplied by the transferred amount. In Example 2, the congestion cost is equal to $2,500.

Time Frames of Energy Markets

Different ISOs/RTOs in the United States coordinate energy markets over different time frames. Energy markets can be day-ahead, hour-ahead, or real-time, depending on when the operating hours occur. The

[5] Exact calculation of the transmission cost is a more complex problem and it requires usage of optimization tools.

illustrated procedure for the market clearing and locational price is applicable to each market. However, some markets have additional decisions that should be made and can influence the generation dispatch. As an example, in a day-ahead market, generating units are dispatched based on several factors including marginal fuel cost and technical constraints, such as start-up and shut-down costs, how fast the unit can go from zero to maximum power output, and the water level for hydro units.

Exhibit 7 summarizes the existing energy markets in the U.S. by ISO/RTO.

Exhibit 7 Energy markets in the U.S.

ISO/RTO	Energy market		
	Day-ahead	Hour-ahead	Real-time
California ISO	Yes	Yes	Yes
ERCOT	Yes	No	Yes
Midwest ISO	Yes	No	Yes
ISO New England	Yes	No	Yes
New York ISO	Yes	No	Yes
PJM	Yes	Yes	Yes
Southwest Power Pool	In 2014	In 2014	Yes

More details about the different markets can be found in the ISO/RTO primers *California Independent System Operator*, *ERCOT Independent System Operator*, *MISO Regional Transmission Organization*, *ISO New England Regional Transmission Organization*, *New York ISO Regional Transmission Organization*, *PJM Regional Transmission Organization* and *Southwest Power Pool, Inc*.