12

Introduction to Competitive Electricity Markets

12.1 Overview: Why Competition?

Historically, the utility companies that ran most power systems were vertically integrated, which means that they were responsible for all development, operation, and commercial activities. This included building and operating generating plants, expanding and maintaining power networks, operating the transmission and distribution networks, and sending electricity bills to the consumers. These companies had a monopoly on all these activities over a service territory that had been allocated to them by a governmental authority. While vertically integrated monopoly utilities are still common, concerns about whether they are the best vehicle to achieve societal goals of economic efficiency, reliability, and sustainability have led some governments to restructure the industry and introduce competitive electricity markets. Because they do not have competitors, monopolies indeed do not have a strong incentive to be efficient. Introducing competition compels companies to make better decisions to thrive or survive. Over time, this improved efficiency should lead to lower costs for the consumers. To make competition possible, the various functions of a vertically integrated utility must be unbundled to separate those where competition is possible from those where a monopoly remains the logical choice. In particular, since building multiple transmission or distribution networks makes no sense from an economic or environmental perspective, network operation and network planning should remain monopoly activities. On the other hand, power plants can compete against each other to supply energy to consumers.

12.2 Fundamentals of Markets

Before delving into the organization and operation of electricity markets, it is useful to introduce some fundamental concepts from economics. Markets are locations where buyers and sellers meet to trade goods. While for millennia these were physical locations, in recent years they have increasingly become virtual. Besides providing a venue for executing transactions, markets also give buyers and sellers the opportunity to collect the information that they need to make decisions. When buyers go to the market (either in person or by browsing

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Companion website:

websites) they can see the different goods that are on offer, compare prices, and decide what to buy. Similarly, sellers can gauge the numbers of potential buyers as well as their interest in the various goods.

This ability to gather information makes it possible for the price of goods to settle at an economically efficient equilibrium. Let us examine how this equilibrium price arises using as an illustration the market for T-shirts. For simplicity, we will assume that all the T-shirts on the market are of the same type and quality. Suppose that a manufacturer of T-shirts has determined that its total cost for producing a quantity q of T-shirts is given by a cost function $C(q)$. The derivative of this cost function with respect to the quantity produced q is called the marginal cost function:

$$MC(q) = \frac{dC(q)}{dq} \tag{12.1}$$

Since the marginal cost is the derivative of the total cost, it depends only on the part of this total cost that varies with the quantity produced (e.g., the labor and the cotton) and not on the fixed part of the cost (e.g., the cost of building the factory). This function thus tells us how much it would cost to produce one more T-shirt. The marginal cost tends to increase with the amount produced because manufacturers incur extra costs (e.g., paying workers overtime) as their production volume increases.[1]

Figure 12.1 illustrates what the marginal cost function typically looks like for a particular manufacturer. Using this marginal cost function, this manufacturer can determine the production level that would maximize its profit. Suppose that it is able to sell any number of T-shirts for π dollars each. As Figure 12.1 shows, if it produces less than q^* T-shirts, each of them costs less to produce than the price at which it could be sold and thus generate a profit. On the other hand, each T-shirt beyond the first q^* costs more to produce than the price at which it can be sold. This manufacturer therefore has no incentive to sell more that q^* T-shirts if the price is π. In other words, the marginal cost function tells us how many T-shirts this manufacturer is willing to sell as a function of the price.

Let us now consider all the manufacturers selling the same T-shirt. Typically, each of them has a somewhat different marginal cost function because they are more or less efficient and purchase the raw materials at different prices. As Figure 12.2 illustrates for the case of two manufacturers, we can aggregate all of these functions into what is called the

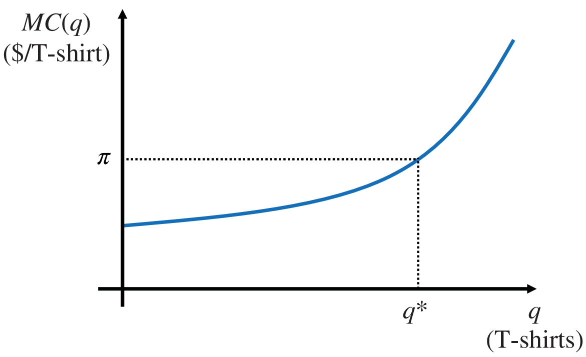


Figure 12.1 Typical marginal cost of production function and optimal production level.

1 The marginal cost of production should not be confused with the *average cost of production,* which is calculated by dividing the total cost of production $C(q)$ by the production volume q. Unlike the marginal cost, the average cost takes into account the fixed costs and initially decreases as the volume increases.

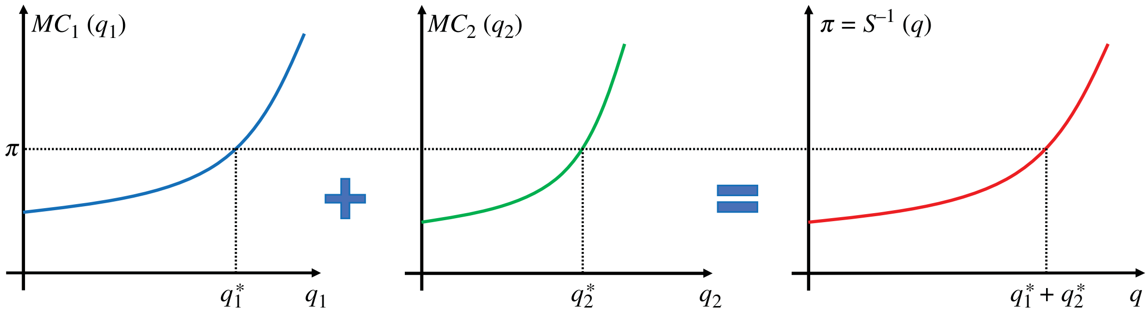


Figure 12.2 Aggregation of two marginal cost functions into an inverse supply function.

inverse supply function, which gives the price that would make these manufacturers willing to sell a quantity q of T-shirts:

$$\pi = S^{-1}(q) \tag{12.2}$$

Looking at this from the other direction, the supply function indicates the quantity that the manufacturers are willing to sell at a given price:

$$q = S(\pi) \tag{12.3}$$

Let us turn our attention to the buyers. People will buy a T-shirt only if the value or utility that they get from owning it is larger than the price they have to pay for acquiring it. While the amount of money that people are willing to pay for a T-shirt is a very individual decision, if we consider all the people who might buy T-shirts, it is clear that the number of T-shirts that they would be willing to buy decreases as the price increases. This is summarized by a demand function:

$$q = D(\pi) \tag{12.4}$$

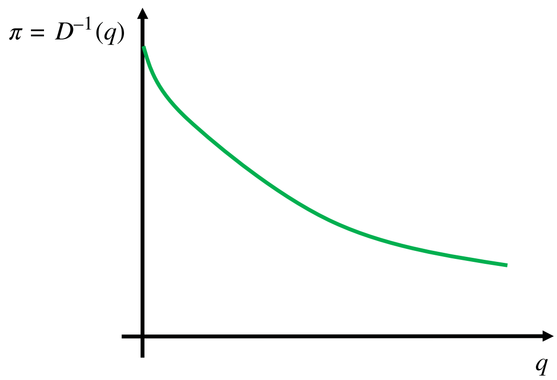
Conversely, the inverse demand function indicates what the price should be for consumers to be willing to buy a certain quantity of T-shirts:

$$\pi = D^{-1}(q) \tag{12.5}$$

Figure 12.3 illustrates the typical shape of a demand or inverse demand function.

When they meet in a market, the suppliers' willingness to sell a commodity such as T-shirts is confronted with the consumers' willingness to buy these T-shirts. We can represent this mathematically by plotting the supply and demand functions on the same

Figure 12.3 Typical shape of an inverse demand function.



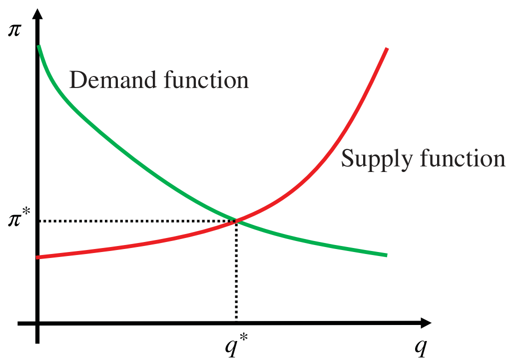


Figure 12.4 Market equilibrium at the intersection of the supply and demand functions.

graph, as shown in Figure 12.4. The intersection of these two curves defines a price π^* such that the quantity q^* that consumers are willing to buy is equal to the quantity that suppliers are willing to sell. Consumers will not buy more than this quantity because the utility that they would derive from these extra T-shirts would be smaller than the price they paid. They will also not buy less than this quantity because they could buy T-shirts for less than the dollar value they put on their utility. Similarly, suppliers will not sell more than q^* because they would have to produce these extra T-shirts at a loss. If they sold fewer T-shirts, they would forgo an opportunity to make a profit. All of these T-shirts will be bought and sold at the same price π^*, which is the price that "clears the market." Even consumers who most desire these T-shirts will not pay more because they can find suppliers who will sell it for that price. Conversely, even the most efficient manufacturers will not sell for less because they can find buyers willing to pay π^*. The market price is thus not just the amount of money coming out of our pockets when we buy a T-shirt. It is also the marginal cost of producing the last T-shirt sold on the market and the marginal utility that consumers place on that shirt. For these reasons, the market price is also called the marginal price.

It must be noted that this efficient market outcome occurs only under perfect competition, a condition that arises only when the market brings together enough sellers and buyers. If some of the sellers or buyers have too big a market share, i.e., sell or buy a very large proportion of the total quantity traded, they hold market power and may be able to artificially raise or lower the market price.

Example 12.1 ***Market Equilibrium*** If the inverse supply function for T-shirts is $\pi = 5 + \frac{q}{100}$ \$/T-shirt and the inverse demand function is estimated to be $\pi = 20 - \frac{q}{50}$ \$/T-shirt, calculate the market clearing price and the number of T-shirts that will be traded.

Since the inverse supply function and the inverse demand function intersect at the market clearing price, we have:

$$20 - \frac{q^*}{50} = 5 + \frac{q^*}{100}$$

Solving this equation, we get $q^* = 500$ T-shirts. Inserting this value in either inverse function gives $\pi^* = 10$ \$/T-shirt.

12.3 Wholesale Electricity Markets

Figure 12.5 illustrates the structure of a basic wholesale electricity market. Generating companies (Gencos) compete against each other to sell the electrical energy produced by the power plants it owns. The buyers in this market are load-serving entities (LSE), each of which supplies the consumers in a given region known as its service area where it also owns and operates the distribution network. Since the energy injected by the Gencos flows to the LSEs through the transmission network, one can say that wholesale competition takes place over the transmission network. An entity called the transmission system operator (TSO) manages this network to ensure that trades do not cause violations of operating limits and reliability issues. To maintain the fairness of the market, the TSO must be a separate entity, independent from the Gencos and LSEs.

While participants in these markets trade electrical energy (MWhs), the physical system is designed to deliver this energy as a continuous flow of electric power (MWs). To reconcile these commercial and practical perspectives, electricity markets define trading periods of typically one hour duration. Thus, when a Genco and an LSE trade a certain number of MWhs, they actually commit to, respectively, inject and extract this number of MW constantly during a given hour-long trading period.

Since flows of electricity are governed by the laws of physics, the energy sold by a given Genco cannot be directed through the network to the LSE that bought it. However, this does not cause any issue because MWhs are interchangeable, and the execution of the various trades can be monitored using meters at both ends.

Trading in wholesale electricity markets can be carried out either bilaterally or in a centralized manner. Bilateral trading is the traditional form of commercial transaction where a buyer and a seller interact directly to negotiate a price and a quantity. However, because the operational constraints of the transmission network must always be respected, the TSO may impose limits on the allowable trades. Centralized trading was developed to facilitate

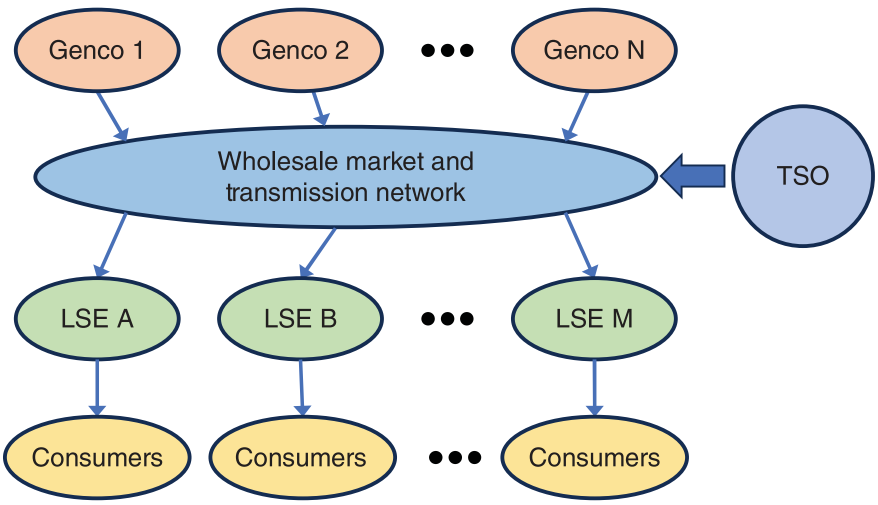


Figure 12.5 Structure of a wholesale electricity market.

the integration of the market with the operation of the transmission system. In a centralized electricity market, LSEs and Gencos do not trade directly with each other, but instead interact separately with the TSO, which takes on the role of market operator. Such market operate as follows for each trading period:

- Prior to the beginning of the trading period, Gencos submit to the TSO offers to sell energy. Each offer takes the form of a quantity/price pairs, for example “100 MW at 23 $/MWh.” The capacity of each generating unit is typically divided into several such offers.
- The TSO ranks these offers in increasing order of price to create the supply curve.
- Similarly, LSEs submit to the TSO bids to buy energy. Each bid also takes the form of a quantity/price pair.
- The TSO ranks these bids in decreasing order or price to create a demand curve.
- The intersection of these supply and demand curves determines the market clearing price and the quantity transacted for this trading period.
- The offers whose price is less than the market clearing price and the bids whose price is higher than the market clearing price are accepted. The others are rejected.
- Gencos and LSEs whose bids and offers were accepted are then committed to inject and extract the corresponding amounts of power during that trading period.

Example 12.2 ***Centralized Wholesale Market Clearing*** Four Gencos and four LSEs participate in the electricity market of the little-known country of Syldavia. They have submitted the offers and bids shown in the table below to the TSO for the trading period between 10:00 am and 11:00 am on June 11.

Offers to sell			Bids to buy		
Genco	**Quantity (MW)**	**Price ($/MWh)**	**LSE**	**Quantity (MW)**	**Price ($/MWh)**
A	100	0.00	P	100	200.00
	100	30.00		100	175.00
	50	50.00		50	150.00
B	100	15.00	Q	100	200.00
	100	40.00		50	175.00
	50	90.00		50	10.00
C	100	0.00	R	100	200.00
	100	25.00		100	175.00
	50	65.00		50	15.00
D	50	10.00	S	100	200.00
	50	20.00		50	175.00
	100	35.00		50	5.00

The TSO ranks these offers to sell in increasing order of price to construct the supply curve shown in Figure 12.6. It also constructs the demand curve by ranking the bids to buy in decreasing order of price. The intersection of these two curves determines the market

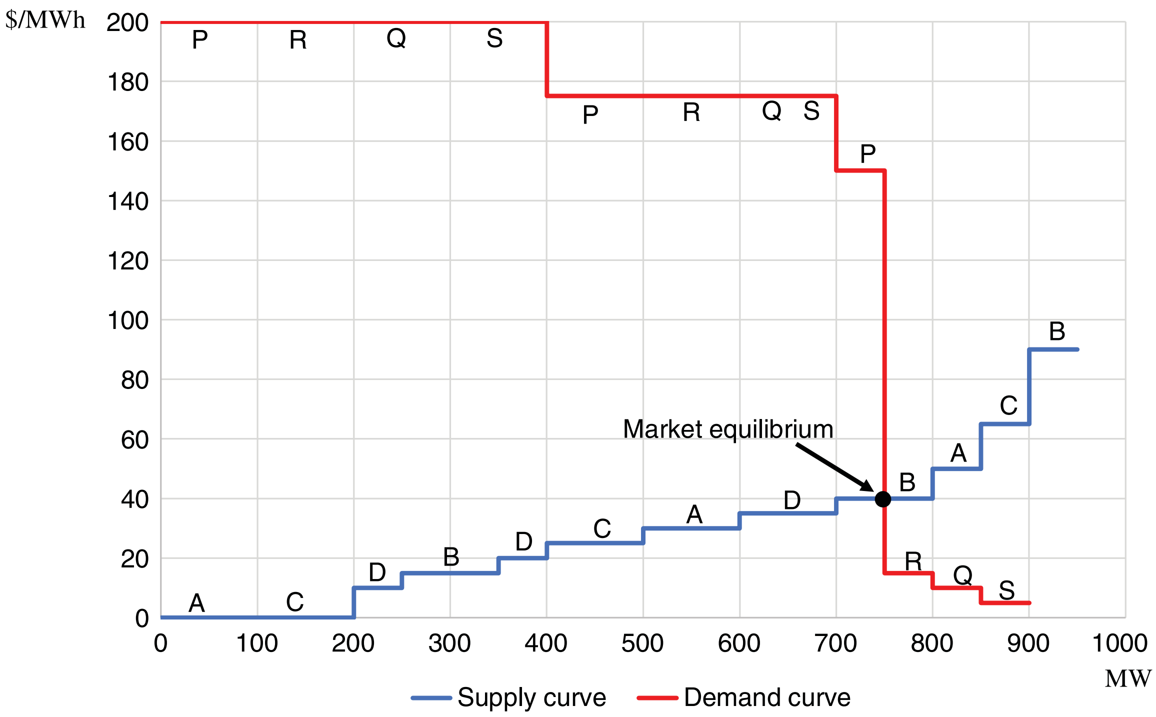


Figure 12.6 Supply and demand curves of Example 12.2. The letters indicate the companies that submitted the bids and offers.

equilibrium. For this trading period, the market clears at 700 MW and 40 $/MWh. The tables below show how each Genco and LSE fared in the market.

Genco	Accepted offers = quantity sold	Revenue
A	100 + 100 = 200 MW	200 × 40 = $8000
B	100 + 50 = 150 MW	150 × 40 = $6000
C	100 + 100 = 200 MW	200 × 40 = $8000
D	50 + 50 + 100 = 200 MW	200 × 40 = $8000
Total	750 MW	$30,000

LSE	Accepted bids = quantity purchased	Expenditure
P	100 + 100 + 50 = 250 MW	250 × 40 = $10 000
Q	100 + 50 = 150 MW	150 × 40 = $6000
R	100 + 100 = 200 MW	200 × 40 = $8000
S	100 + 50 = 150 MW	150 × 40 = $6000
Total	750 MW	$30,000

All the offers below the market price and the bids above the market price are accepted, while the other bids and offers are rejected. Only 50 MW of Genco B's offer of 100 MW at 40 $/MWh was accepted as this was the residual quantity needed to clear the market. This offer thus set the market price.

12.4 Bidding in a Centralized Market

As mentioned above, if a sufficiently large number of companies participate in a market, competition is deemed to be perfect. In such cases, the optimal bidding strategy for a Genco is to submit offers that reflect its marginal cost of generation. If an offer is accepted, it will be paid at the market clearing price, yielding a profit for the Genco. If it is not accepted, the Genco avoids having to produce at a loss. On the other hand, if the Genco offered at a price above its marginal cost, its offer could be rejected, and it would have to forgo an opportunity to make a profit. Conversely, if it offered at a price below its marginal cost, it could be forced to produce at a loss.

When the market is less competitive, for example when the expected demand is high and most of the available generation capacity is likely to be needed, Gencos usually submit some offers at prices substantially higher than their marginal cost. When these offers are accepted, they drive up the market clearing price and increase the profitability of all the accepted offers.

The supply curve of Figure 12.6 reflects these practices. For example, Gencos A and C both offered 100 MW at a price of 0 $/MWh because these companies intend to produce this power with renewable resources such as wind and solar that have a negligible marginal cost of production. The middle part of the supply curve rises gradually, reflecting differences in the heat rate and fuel cost of thermal power plants. The curve then rises more steeply, reflecting offers trying to take advantage of the reduced competitiveness.

While the price directly affects the Gencos' willingness to sell, it has a very limited influence on the amount that LSEs buy. Consumers indeed expect to be able to draw whatever power they need to get on with their lives and businesses independently of what happens in the market. A few of them may be willing to reduce their consumption if the price is too high. A few others can take advantage of a very low price to temporarily increase their demand. As the demand curve of Figure 12.6 illustrates, LSEs will therefore price most of their bids to guarantee that they will be above the market price. A few bids (e.g., LSE P's bid at 150 $/MWh) reflect the willingness of some consumers to curtail their demand. On the other hand, the bids of LSEs Q, R, and S between 5 and 15 $/MWh suggest that they would increase their load or store energy for future use if the price was sufficiently low. Some centralized electricity markets neglect the effect of the price on the demand and replace the demand curve by a vertical line at the value of the load forecast for the trading period. Economists describe such a vertical demand curve as being perfectly inelastic. In Example 12.2, replacing the demand curve of Figure 12.6 by a 750 MW forecast would not change the market clearing.

12.5 Variation of Market Price with Time

As we discussed in Chapter 2, the consumers' demand for electricity changes as a function of the time of day, time of the year, and weather conditions. Similarly, wind and solar generation also make the quantity offered dependent on these factors. The market equilibrium will therefore change with each trading period. In particular, the market price will increase when the demand rises and the supply decreases. Conversely, it will drop when the demand decreases or the supply increases.

Example 12.3 ***Time-varying Prices*** For simplicity, suppose that the Gencos of Example 12.2 submit the same offers for every hourly trading period of June 11. As discussed at the end of the Section 12.4, we will neglect the effect of the price on the demand curve and represent the demand by a vertical line at the value of the load forecast. The table below gives the values of these hourly forecasts.

Hour	1	2	3	4	5	6	7	8	9	10	11	12
Load	390	375	300	275	225	300	425	550	650	750	775	825
Hour	13	14	15	16	17	18	19	20	21	22	23	24
Load	810	775	750	750	825	875	925	825	750	650	450	425

Figure 12.7 illustrates the market equilibrium for hours 5 (minimum demand), 10, 19 (maximum demand), and 23. Figure 12.8 shows how the market price evolves over the course of that day.

Figure 12.9 illustrates the typical range of prices that arise in an actual electricity market, in this case ISO New England during the year 2022. This price duration curve shows the percentage of the number of hours in a year during which the price exceeds a certain value. Note the small number of hours during which prices reach extremely high values.

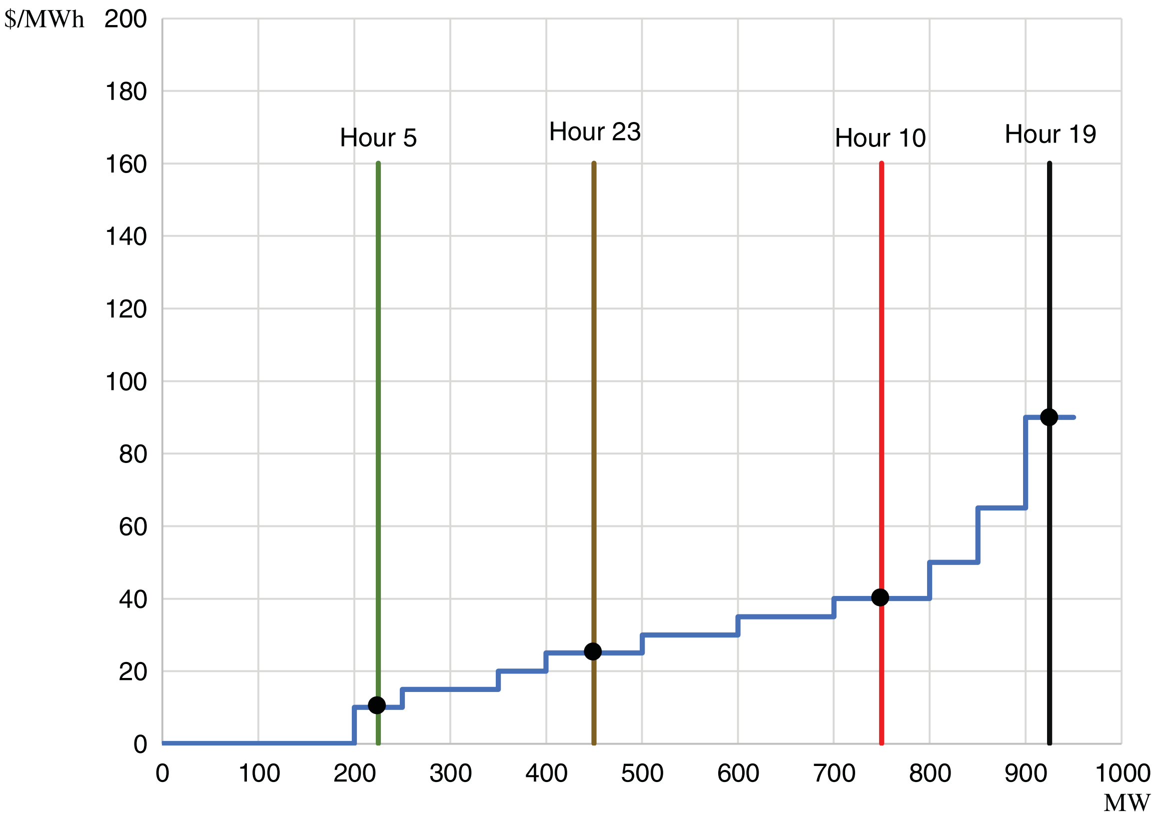


Figure 12.7 Market equilibrium at different hours of the day.

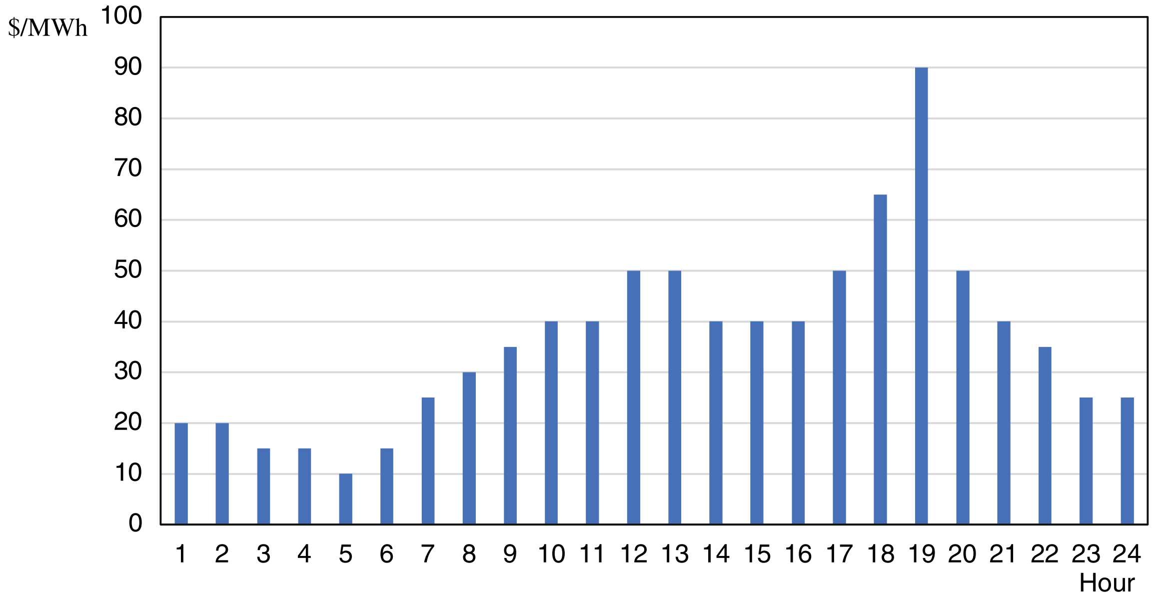


Figure 12.8 Evolution of the market price over the course of the day in Example 12.3.

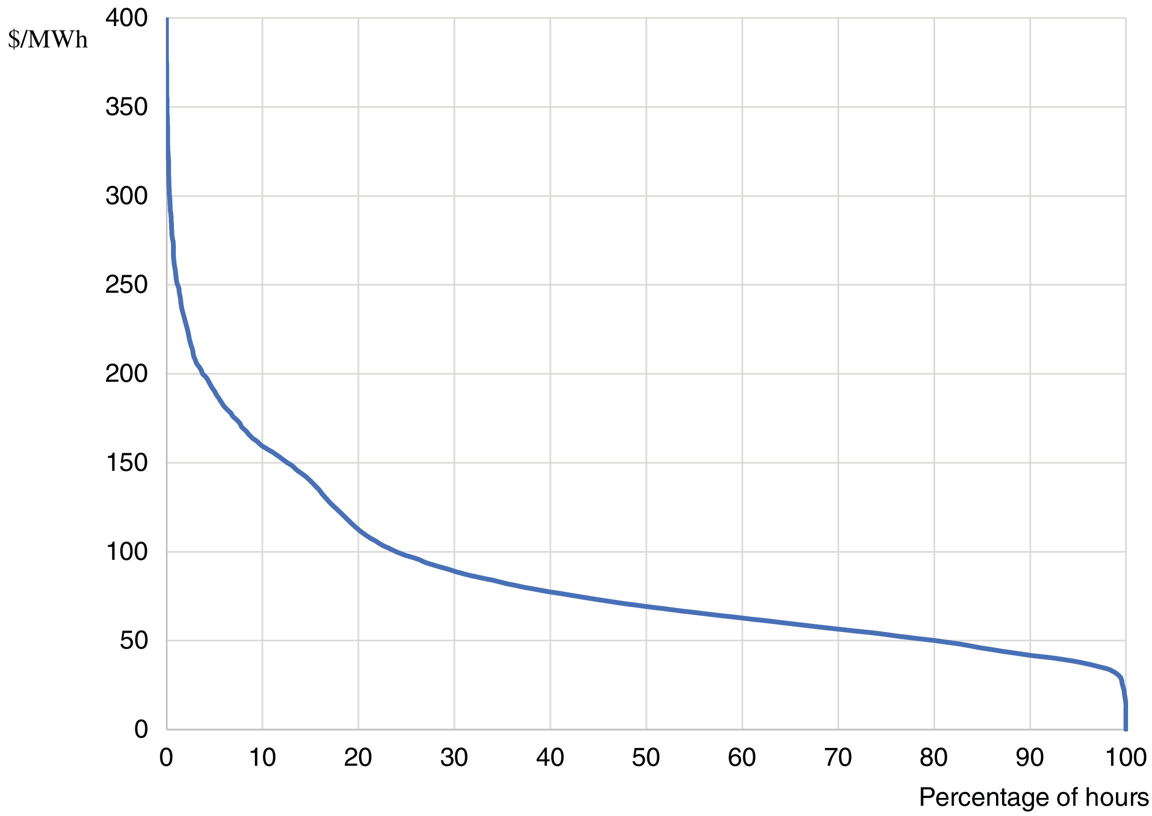


Figure 12.9 Price duration curve for ISO-NE during 2022. The highest price was 374.98 $/MWh, the lowest 14.02 $/MWh, and the average 85.56 $/MWh. Source: Adapted from www.iso-ne.com.

12.6 Effect of Transmission Capacity Limits

So far, we have assumed that at each trading period the market equilibrium is determined by the intersection of supply and demand curves that combine the offers and bids of all the Gencos and LSEs. Each generator then produces power according to its accepted offers and the market price is applied uniformly to all the energy transacted. However, the generation pattern resulting from these accepted offers would often cause power flows that violate operational limits on the transmission network. Since this is unacceptable, the market clearing process must be modified to satisfy these constraints. Essentially, some cheaper offers at the "wrong" location must be rejected and replaced by more expensive offers in the "right" place. A consequence of these adjustments is that the market price is then no longer uniform. Instead, the price that Gencos receive, and that LSEs pay, depends on where they inject or extract power in or out of the grid. This practice is called locational marginal pricing.

Example 12.4 ***Locational Marginal Pricing*** The electricity market of Syldavia that we introduced in in Example 12.2 is divided into two regions connected by a transmission line rated at 50 MW. Gencos A and D are located in the Western region, while Gencos B and C are located in the Eastern region. These four Gencos have submitted the same offers as in Example 12.2. The demand is modeled as an inelastic 750 MW load, 225 MW of which is in the Western region and 525 MW in the Eastern region. Figure 12.10a illustrates what would happen if the 50 MW limit on the transmission line was ignored when clearing the market. Generation would then exceed the load in the Western region, and 175 MW would flow from West to East on the transmission line. Since this exceeds the 50 MW rating of this line, generation in the Western region must be reduced by 125 MW and increased by the same amount in the Eastern region. Referring to Figure 12.6, we see that this will require rejecting D's 100 MW offer at 35 $/MWh and curtailing A's offer at 30 $/MWh to 75 MW. To compensate, in the Eastern region, the remaining 50 MW of B's offer at 40 $/MWh must be accepted, as must C's 50 MW offer at 65 $/MWh and 25 MW of B's offer at 90 $/MWh. Figure 12.10b illustrates the generations and flow that result from this improved market clearing.

Another way of approaching this problem is to observe that the transmission constraint splits what we treated as a single market into two markets, one for the Western region and one for the Eastern region. In the Western market, A and D compete to supply the 275 MW demand (225 MW of local load plus the 50 MW outflow on the transmission line). In the Eastern market, B and C compete to supply the 475 MW demand (525 MW of local load minus the 50 MW inflow on the transmission line). As Figure 12.11 illustrates, the Western market clears at 30 $/MWh, while the Eastern market clears at 90 $/MWh. Generators in the Western region thus collect less revenue for each MW that they produce than their counterparts in the Eastern region. The transmission constraint also reduces the amount of energy that they can sell. Conversely, consumers in the Eastern region pay more for electrical energy than consumers in the Western region because the transmission constraint prevents them from accessing the cheaper Western generation.

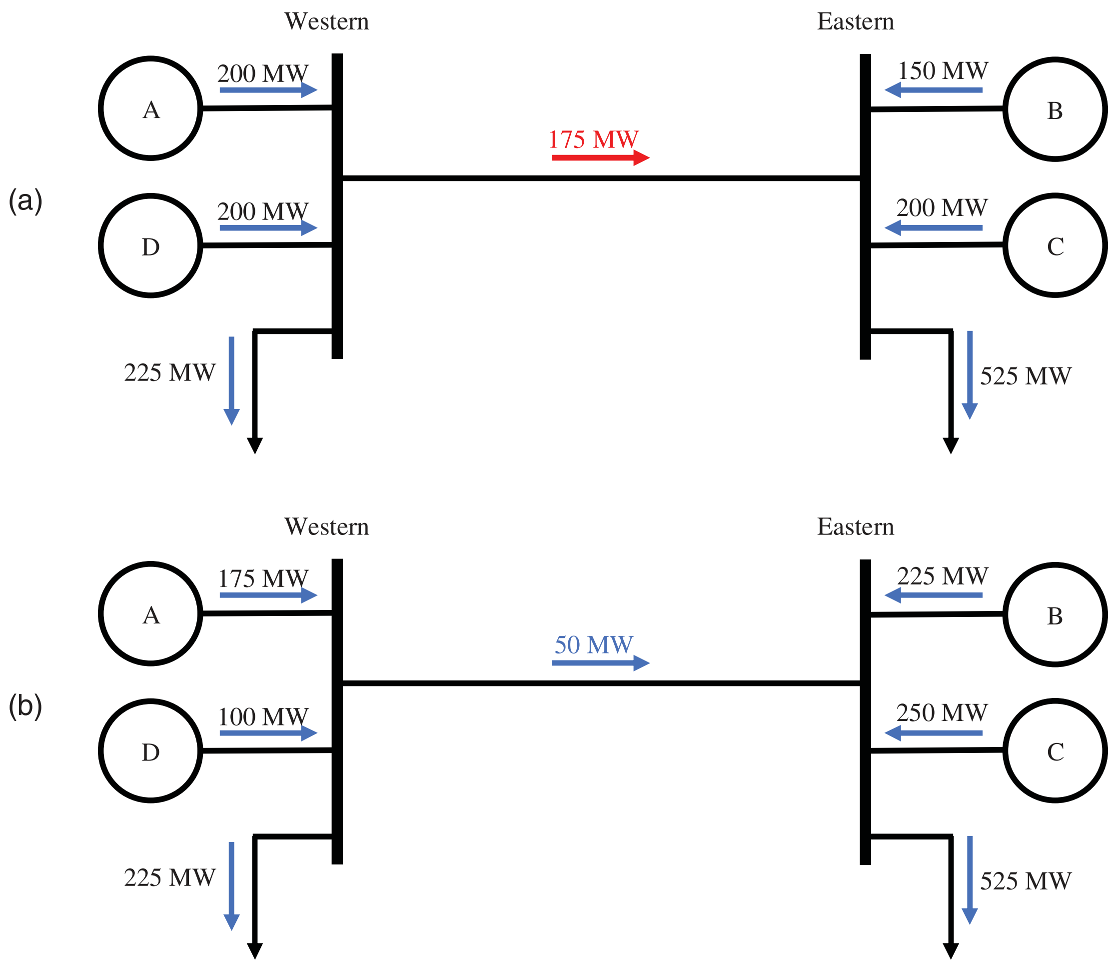


Figure 12.10 Generations and flow in the Syldavian electricity: (a) If the transmission constraint is ignored; (b) if the transmission constraint is incorporated in the market clearing process.

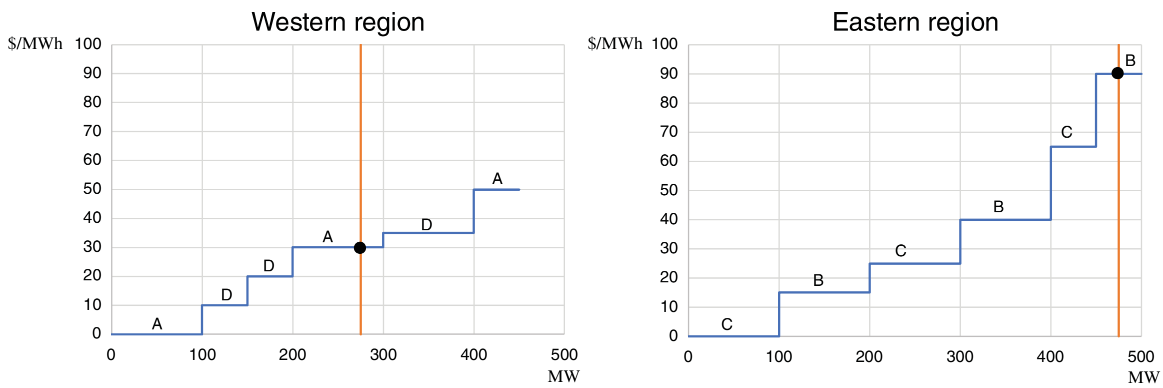


Figure 12.11 Market clearing in the Western and Eastern regions of the Syldavian electricity market.

Because the electricity market of the previous examples comprises only two zones connected by a single transmission line, it was relatively easy to identify what must be done to optimally adjust the results of the market to ensure that they respect the transmission limits. Clearing the market in actual systems where generators and loads are located at many nodes connected through multiple paths requires the solution of a linearized version of the optimal power flow problem described in Section 8.8. It can be shown that the prices of electrical energy at each bus are then given by the dual variables (Lagrange multipliers) associated with the corresponding power balance

12.7 Two-Settlement Markets

As we discussed in Section 6.5, substantial savings can be achieved if the operation of thermal generating units is scheduled over a day or more. Performing a unit commitment indeed makes it possible to optimize the number and type of generating units that are connected, to amortize their startup-costs, and to respect their operating constraints. To retain this benefit, many electricity markets operate both a day-ahead market and a balancing market.

On day D-1 of a day-ahead market, Gencos submit their offers to provide energy for every hourly or half-hourly trading period of day D. In addition to price-quantity pairs, these offers also specify the startup cost of the generating units and their operational constraints. At the same time, LSEs submit their demand curve for each trading period of day D. A complex calculation that combines a unit commitment and an optimal power flow then clears the market, i.e., determines the power to be produced or consumed by each entity at each location and every trading period, as well as all the locational marginal prices for all trading periods.

However, many things can happen between day D-1 and each trading period on day D: large generating units fail, wind and solar generation exceed expectations, load forecasts turn out wrong. To keep the system in balance, the power injections scheduled on D-1 must be incrementally adjusted up or down. Balancing markets operate shortly before real-time and are designed to determine these adjustments in an economically efficient, market-driven manner. In these markets, Gencos that can adjust their output quickly submit offers to increase or decrease their generation over 5- to 15-minute trading periods. LSEs that have the ability to alter their loads can also participate. The TSO determines which of these bids and offers it needs to call upon to keep the system in balance. The price of the most expensive bid or offer selected sets the real-time price.

Transactions cleared in the day-ahead market are settled at the day-ahead prices as if the energy actually produced or consumed was exactly equal to what had been scheduled. Any difference between the amounts scheduled on the day ahead and the actual values is settled at the real-time price.

Example 12.5 ***Two-settlement Market*** On June 10, the day-ahead electricity market of Syldavia cleared the hourly trading period 8 of June 11 at a price of 23 \$/MWh at bus Patagonia. At this location during that trading hour Genco Blue was scheduled to inject 100 MW while LSE Orange was scheduled to extract 50 MW. The table below shows what Blue and Orange actually injected and extracted during each of the 15-minute trading intervals of the balancing market for hourly trading period 8. It also shows the real-time price at bus Patagonia, which reflects the bids and offers that the TSO accepted to maintain the power balance at that bus while respecting the operational constraints on the transmission network.

Trading interval	Injection by Blue (MW)	Extraction by Orange (MW)	Real-time price ($/MWh)
7:00–7:15	92	50	25.00
7:15–7:30	104	46	20.00
7:30–7:45	100	54	23.00
7:45–8:00	20	42	30.00

The table below summarizes the settlement of the day-ahead (DA) and real-time (RT) markets for Genco Blue for hour 8 of June 11. According to the standard accounting convention, parentheses indicate a negative value, i.e., an expense. The factors ¼ convert MW imbalances over a 15-minute period to a MWh value. Note the significant loss that Genco Blue incurred during the 7:45–8:00 trading interval because its injection fell significantly below the scheduled value.

Trading period	MWh	Price	Amount
DA: 7:00–8:00	100	23.00	$2300
RT: 7:00–7:15	$\frac{1}{4} \times (92 - 100) = -2$	25.00	($50)
RT: 7:15–7:30	$\frac{1}{4} \times (104 - 100) = 1$	20.00	$20
RT: 7:30–7:45	$\frac{1}{4} \times (100 - 100) = 0$	23.00	$0
RT: 7:45–8:00	$\frac{1}{4} \times (20 - 100) = -20$	30.00	($600)
		Total:	$1670

The settlement for LSE Orange is shown below.

Trading period	MWh	Price	Amount
DA: 7:00–8:00	50	23.00	($1150)
RT: 7:00–7:15	$\frac{1}{4} \times (50 - 50) = 0$	25.00	$0
RT: 7:15–7:30	$\frac{1}{4} \times (50 - 46) = 1$	20.00	$20
RT: 7:30–7:45	$\frac{1}{4} \times (50 - 54) = -1$	23.00	($23)
RT: 7:45–8:00	$\frac{1}{4} \times (50 - 42) = 2$	30.00	$60
		Total:	($1093)

12.8 Ancillary Services

While the TSO is responsible for reliably operating the transmission system, it does not own the resources needed to do so. It must therefore enter into contracts with Gencos and other entities that own these resources and can provide the necessary services. These services are called ancillary because they are accessory to the markets for energy but do not involve the recurring provision or consumption of a substantial amount of energy. The definition of these services varies from market to market, but typical examples include:

- *Contingency reserve*: As we discussed in Chapter 6, the system must be able to recover from a sudden significant imbalance between load and generation. This is possible only if enough generation capacity is held in reserve to respond to such contingencies. Since this reserve capacity cannot be used to produce and sell energy, generators that provide this service must be compensated for this loss of opportunity. Owners of battery energy storage systems, as well as large industrial consumers that are willing to disconnect part of their load at very short notice, can also provide this service.

- *Frequency control*: As we also discussed in Chapter 6, random fluctuations in load and generation cause small deviations in the system frequency. To maintain the frequency close to its nominal value, small adjustments must be made on a continuous basis to the power injections. On average, the net amount of energy required is close to zero. Generators operating on automatic generation control customarily provided this service. However, in recent years it has become a substantial source of revenue for battery energy storage systems.
- *Reactive power*: TSOs rely on the reactive power supplied by generators to control the voltages in the transmission network. However, as the loading capability diagrams of synchronous generators show (Figure 4.20), providing reactive power limits a generator's ability to supply active power and thus restricts its owner's opportunity to participate in the energy markets. Generators that inject reactive power must therefore be compensated for providing this service.
- *Black start capacity*: Before a large thermal generating units can be synchronized to the grid, a substantial amount of power is required to run its auxiliary systems (e.g., pumps and coal crushers) Under normal circumstances, this is just another load on the grid. However, in the event of a blackout, all generating units shut down and no power is immediately available to restart them. To restore the grid to a normal operating state, some generating units must therefore be able to restart without access to an external power source. These so-called black start generating units are typically hydro plants or small diesel generators whose power output is sufficient to restart the larger thermal units. These black start generating units are often not competitive in the energy markets. Since all power systems will at some point suffer a blackout, some Gencos must be compensated to maintain generating units with enough black start capacity.

12.9 Retail Markets

In some jurisdictions, the wholesale market has been complemented by a retail market. As Figure 12.12 illustrates, in these markets, companies called retailers purchase electrical energy in bulk on the wholesale market. These retailers then compete against each other to sell energy to individual consumers on the retail market. Since the retailers purchase electricity at the locations where distribution networks are connected to the transmission network and resell it to consumers who are located at the edges of the distribution network, one can say that retail competition takes place over the distribution networks. To ensure the fairness of the retail markets, these distribution networks are usually owned and operated by distribution companies (Discos) that are separate from the retailers.

12.10 Unbundled Industry Structure

The introduction of wholesale and retail electricity markets has required the breakup of vertically integrated, monopoly utilities. In the following paragraphs, we describe how the

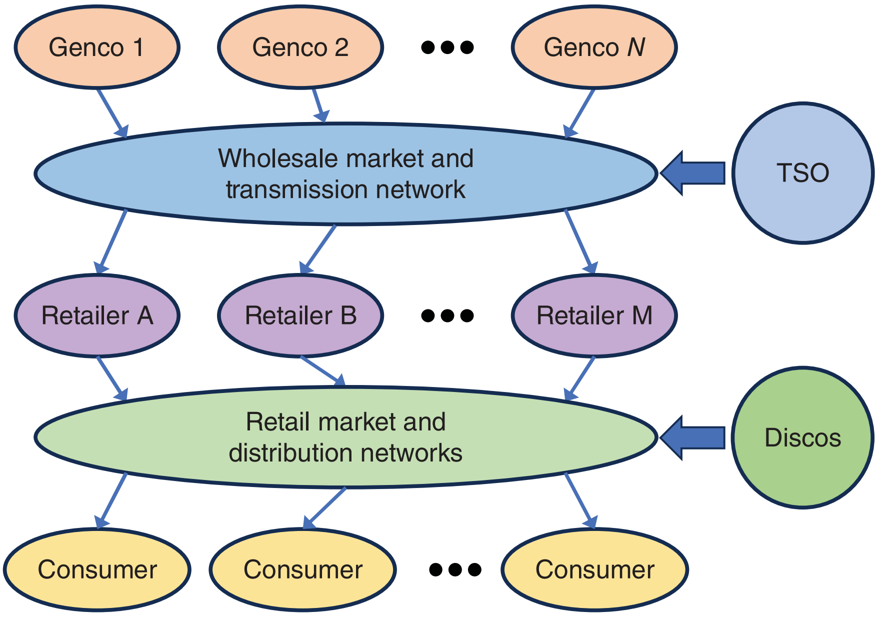


Figure 12.12 Combination of wholesale and retail electricity markets.

various functions that these utilities performed are typically unbundled between different types of companies. We also briefly discuss their sources of revenues.

A **generating company** (Genco) owns and operates one or more power plants. Some Gencos specialize in a specific generation technology (e.g., nuclear, wind), while others prefer to operate a portfolio of different types of plants. They collect revenues from the sale of energy and the provision of ancillary services.

Retailers buy electricity in bulk on the wholesale market and resell it to consumers at retail rates. To be profitable, these retail rates must be higher than the average price at which they purchased energy on the wholesale market. Retailers usually do not own significant physical assets.

A **transmission company** (Transco) owns and operates all the lines, substations, and other equipment that support the transmission of power from the generators to the distribution networks over a given geographical area. Transcos are thus regulated monopoly companies. They charge usage fees to the Gencos and retailers that inject and extract power in or out of their network.

A **distribution company** (Disco) owns and operates the distribution network serving a given geographical area. They are thus also regulated monopoly companies. Their revenues stem from fees that all consumers in their service area pay through their retailer.

The primary responsibility of the **transmission system operator** (TSO) is to maintain the reliability of the transmission system while operating the wholesale market in a fair and economically efficient manner. In some jurisdictions, it is called the independent system operator (ISO) or the regional transmission organization (RTO). These entities are usually non-profit and cover their costs by charging fees to users of the system. The only physical assets owned by TSOs are the control center and the communication equipment required for the day-to-day operation of the system. TSOs also often provide a forum where stakeholders can discuss and decide how to upgrade or expanding the transmission network.

Owners of storage systems can perform arbitrage in the wholesale electricity market, i.e., buy energy to charge their batteries when the price if low, and discharging these batteries to resell this energy when the price is high. They can also provide ancillary services to the TSO. Alternatively, they can operate in conjunction with renewable generators to firm up wind or solar energy and sell it at the best possible price.

Nowadays many aspects of power systems operate on the basis of free market economics. However, there is still a need for **regulators**. These government organization fulfill several functions. First, they ensure that the rules of the market are fair and encourage competition. Second, they set the rates that monopoly transmission and distribution companies can charge for the use of their networks. Third, they enforce the technical standards that all the types of companies described above must abide by to ensure the reliability of the power systems. In the United States, wholesale markets and transmission networks are regulated at the federal level while the various states regulate the retail markets and distribution networks.

Further Reading

Kirschen, D.S. and Strbac, G. (2018). *Fundamentals of Power System Economics*, 2e. Wiley.

Problems

P12.1 Suppose that the inverse demand function for jeans in a university town is $\pi = 100 - 0.01q$ \$/jean and the inverse supply function is estimated to be $\pi = 20 + 0.01q$ \$/jean. Calculate the market clearing price and the number of jeans traded.

P12.2 Given that the inverse supply function for T-shirts is $\pi = 15 + 0.01q$ \$/shirt and the demand function is $q = 700 - 10\pi$, calculate the market clearing price and the quantity traded.

P12.3 Economists estimate that the variable cost of production of electrical energy in the Bordurian electricity market is given by the following expression:

$$C(Q) = 20{,}000 + 500Q + 10Q^2\ (\$) \quad \text{for } Q \leq 90\,\text{MWh}$$

$$C(Q) = 141{,}400 + 287.5(Q - 86)^2\ (\$) \quad \text{for } Q \geq 90\,\text{MWh}$$

where Q is in MWh.
They also estimate that the demand curve for electricity is given by the following expressions:
For the hour of maximum load: $Q = 100 - 0.00125\pi$ (MWh)
For the hour of minimum load: $Q = 55 - 0.001\pi$ (MWh)
where π is the price in \$/MWh.

a. Sketch the supply and demand curves for this market.

b. Determine the following quantities at the market equilibrium for the hour of minimum load and the hour of maximum load:
   - The quantity traded.
   - The market price.
   - The revenue collected by the producers.
   - The total variable cost of production for all the producers.

P12.4 The supply curve for a commodity is given by the following expression:

$$\pi = 1000 + 20\,Q + 0.1\,Q^2 \quad (\$)$$

where π is the price of the commodity and Q is the quantity.
Consider the following three demand curves for this commodity:

a. $\pi = 5000 - 20Q$
b. $\pi = 3000$
c. $Q = 100$

For each of these curves, determine the following quantities at the corresponding market equilibrium:

- The quantity traded.
- The market price.
- The revenue collected by the producers.
- The total variable cost of production for all the producers.
- The economic profit collected by these producers.

P12.5 Economists assess the consumers' sensitivity to the price of a commodity using a measure called the price elasticity of the demand, which is defined as the relative change in demand that results from a relative change in price:

$$\varepsilon = -\frac{\frac{dq}{q}}{\frac{d\pi}{\pi}} = -\frac{\pi}{q}\frac{dq}{d\pi}$$

Calculate this elasticity for each of the market equilibria of Problem P12.4.

P12.6 Given that the supply function for the widget market is $q = 0.2\pi - 40$ and the demand function: $\pi = -10q + 2000$, calculate:

a. The demand and the price at the market equilibrium.
b. The producers' revenue.
c. The producers' production cost.
d. The producers' profit.

P12.7 The TSO of the centralized electricity market of Borduria has received the following day-ahead bids and offers for the 10:00–11:00 trading period of January 25.

Offers to sell			Bids to buy		
Genco	Quantity (MW)	Price ($/MWh)	LSE	Quantity (MW)	Price ($/MWh)
Blue	300	10.00	Maple	250	300.00
Blue	100	30.00	Maple	200	250.00
Blue	50	60.00	Maple	50	20.00
Green	150	0.00	Oak	150	325.00
Green	200	20.00	Oak	100	275.00
Green	50	100.00	Oak	50	5.00
Orange	250	15.00	Fir	300	300.00
Orange	200	40.00	Fir	100	25.00
Orange	50	80.00	Fir	50	10.00
Purple	250	25.00	Larch	200	250.00
Purple	200	50.00	Larch	275	250.00
Purple	50	120.00	Larch	75	150.00

a. Build and plot the supply and demand curves for this trading period.
b. Determine the market price and quantity traded during this trading period.
c. Calculate the revenue collected by each Genco for this trading period.
d. Calculate the amount paid by each load serving for this trading period.

(Hint: Draw the supply curve neatly as you will need if for subsequent problems.)

P12.8 Instead of using a demand curve, let us assume that the electricity market of Borduria uses a price-insensitive forecast of the load to model the demand.

a. Using the supply curve that you determined in Problem 12.7, determine the market price and the accepted offers if this load is forecasted to be 1200 MW for a given hourly trading period. Calculate the revenue collected by each Genco.
b. If the load is divided among the LSE as shown in the table below, calculate how much each of them will have to pay for this trading period.

LSE	Fraction of system load
Maple	20%
Oak	30%
Fir	40%
Larch	10%

P12.9 Assuming that the supply curve you determined in P12.7 is valid for all the hourly trading periods of that day, draw a graph of the market price as a function of the time of day if the market clears at the quantities shown in the table below.

Hour	1	2	3	4	5	6	7	8	9	10	11	12
MW	950	800	725	625	800	950	1100	1325	1400	1500	1550	1600
Hour	13	14	15	16	17	18	19	20	21	22	23	24
MW	1625	1550	1425	1400	1500	1600	1725	1820	1775	1600	1300	1100

P12.10 Assume that the Gencos have submitted the same offers to the electricity market of Borduria that we introduced in Problem P12.7 and that a price-insensitive forecast of the load is used to model the demand.

a. Calculate the market price, the accepted offers, and the revenues of each Genco for a load of 1300 MW.
b. This market is divided into two regions connected by a single transmission line rated at 50 MW. Gencos Blue and Green are located in the Northern region while Gencos Orange and Purple are located in the Southern region. Calculate the market price and the accepted offers in each region, as well as the revenues of each Genco if the load is 500 MW in the Northern region and 800 MW in the Southern region.
c. Discuss the differences between the results of parts a and b. Under these conditions, who would gain and who would lose if the capacity of the transmission line was increased?

P12.11 Repeat Problem P12.10 assuming that the load is 875 MW in the Northern region and 425 MW in the Southern region.

P12.12 Genco PowerMax injects power in Northern Borduria while LSE BPower extract power in Southern Borduria. Both participate in the electricity market of Borduria. At the close of the day-ahead market for November 5, for the 13:00–14:00 hourly trading period PowerMax had sold 300 MW at the northern price of 30.00 \$/MWh, while BPower had bought 200 MW at the southern price of 25.00 \$/MWh.

The electricity market of Borduria also operates a real-time market on 15-minute intervals that is used to settle imbalances between commitments in the day-ahead market and actual power injections. The table below shows the performance of these two companies as well as the real-time prices between 13:00 and 14:00 on November 5. Calculate the net revenue or expense for these two companies during this hourly trading period.

Trading interval	PowerMax injection (MW)	BPower extraction (MW)	Northern real-time price (\$/MWh)	Southern real-time price(\$/MWh)
13:00–13:15	296	204	32.00	25.00
13:15–13:30	304	192	30.00	24.00
13:30–13:45	100	200	40.00	30.00
13:45–14:00	0	208	50.00	28.00