Free markets. Real solutions.

R STREET'S ELECTRICITY 101 SERIES
NO. 3

August 2016

ECONOMIC CHARACTERISTICS OF ELECTRICITY

INTRODUCTION

The physical fundamentals of energy inform the economic fundamentals of electricity. Power plants that generate electricity face both fixed and variable costs. Fixed costs do not vary with the level of output; they primarily include capital costs and land costs associated with building a facility. The costs faced by transmission and distribution facilities are almost entirely fixed.

The variable costs of electricity – including fuel, labor and maintenance costs – depend on a power plant's level of output. Over the short term, these are captured by looking to a plant's marginal cost – that is, the cost to produce one more increment of output. Marginal cost provides the conceptual basis for cost-effective operation of the electricity system.

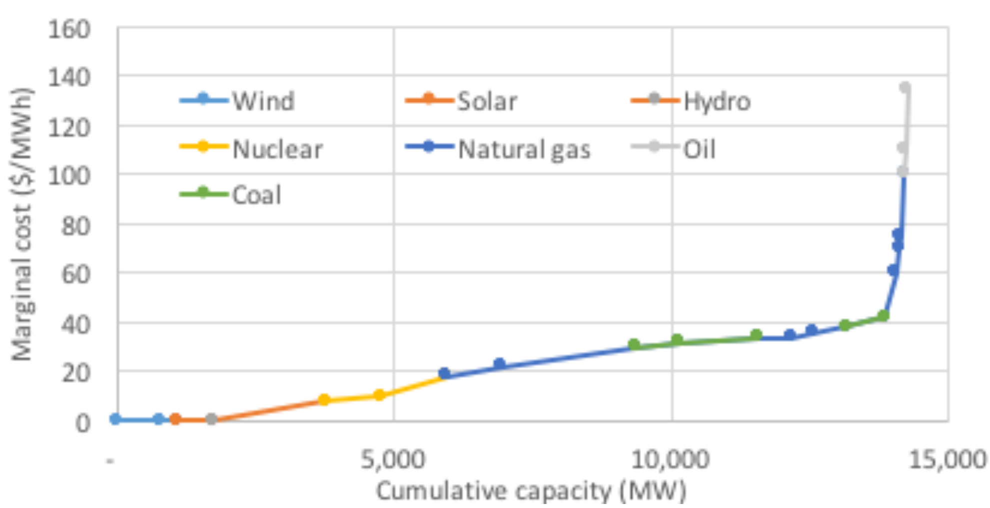
OPERATIONAL ECONOMICS

Unique short-term supply-and-demand characteristics make electricity an unusual product. Notably, all producers and consumers require access to a shared network (transmission), where the actions of some participants can affect the quality of service received by others. The challenge of balancing supply and demand is compounded by the lack of cost-effective storage options, like batteries. This makes the system very sensitive to short-term supply and demand shifts.

Historically, consumers had no way to assess real-time grid conditions for themselves, meaning they also had no way to adjust their consumption accordingly. Advances in technologies and services have given customers new information about grid conditions, like high costs on hot evenings or low costs on cool mornings. Nonetheless, most customers remain unresponsive to these changing grid conditions, which can cause rapid fluctuations in the marginal cost of generation. Some large consumers are a notable exception and change their demand according to grid conditions in order to save money on their bills.

Operating the grid in the "least-cost" manner requires minimizing generation costs. This involves dispatching gen-

FIGURE 1: AN ILLUSTRATION OF TYPICAL ENERGY SUPPLY CURVE



erators in order of lowest to highest marginal cost to meet demand. The primary component of marginal cost for generators is fuel. This is determined both by fuel cost and by the efficiency with which a generator converts fuel into electricity. The result largely drives the shape of the supply curve. Fuel costs vary little over months for coal and nuclear generators, who usually sign long-term fuel contracts. Natural gas costs can vary substantially between and within a day, which shifts the supply curve considerably. Wind and solar, given their free fuel supply, have marginal costs near zero. Their dependence on the weather shifts the supply curve considerably. Most generators also incur substantial costs to start, shut down and adjust their output.

The marginal cost to serve demand, or "load," in a particular area depends on the marginal cost of generation and the typically small "line loss" associated with transmitting power over transmission and distribution lines. Load also is limited by transmission availability. If power from the least-cost generator cannot flow to a load area because of constraints on the transmission system, the least-cost generator who can serve that load moves up in the dispatch order. The difference between these two generators' marginal cost is referred to as the "marginal cost of transmission congestion." This represents the extra cost to satisfy demand when transmission constraints require generation to be redispatched.

TABLE 1: ECONOMIC CHARACTERISTICS BY FUEL TYPE

Type	Fixed costs	Marginal costs
Coal	Medium	Medium
Natural gas	Low	Low to high
Nuclear	High	Low
Hydroelectric	Medium	Zero
Solar	High	Zero
Wind	Medium	Zero
Oil	Low	High

INVESTMENT ECONOMICS

Historically, units with higher fixed costs – like nuclear, hydroelectric and coal – had low marginal costs. These units would provide the lowest average cost of electricity when they were operated frequently. As such, they were built to run at a steady level in a "baseload" role – that is, to meet minimum levels of demand. It proved more cost-effective to build low fixed-cost generation, like natural gas and oil, to meet less-frequent demand needs.

In recent years, cheap natural-gas prices have usually made it more cost-effective to build natural-gas power plants in a baseload role than either coal or nuclear. Wind and solar expansion has contributed to lowering marginal generation costs, but their variability limits those sources' ability to replace conventional power plants. This is because their maximum output capability at peak periods is constrained by weather.

Electric infrastructure is capital-intensive, meaning its fixed costs are high relative to its variable costs. Spreading fixed costs out over a greater scale results in lower average per-unit costs, thus offering what are known as economies of scale. For example, building and operating a 600 MW plant is less expensive than two 300 MW plants.

Electric infrastructure also is long-lived, operating for decades at a time. It requires long lead times to build. Once built, the high fixed costs become large sunk costs (that is, costs that were already incurred) to generation owners. This magnifies the consequences of poor investment decisions. Furthermore, investment economics depends on a variety of conditions that are difficult to predict, such as fuel prices, technology advances and policy changes. All these factors make generation investment risky for investors.

These features have made long-term planning an indispensable tool to minimize cost and risk. Through a process commonly known as "integrated resource planning" (IRP), producers aim to determine the least-cost mix of resources. This involves evaluating the fuel type, size and timing of new resource investments and retirements to meet expected future demand. For example, many IRPs in recent years support expanded demand-side management programs, construction of new natural-gas-fired generation and retirement of coal-fired generation. Policy interventions that deviate from IRP principles, such as those dictating a part of the fuel mix, tend to result in higher-cost investments.

Characteristics like enormous economies of scale and the inefficiencies of duplicate transmission and distribution system investments led the electric power industry historically to be designated a natural monopoly. This meant that one firm would provide electricity at lower cost than multiple, competing firms. For example, a firm with an existing transmission network can expand its network at lower cost than a new entrant starting from scratch.

New technologies reduced the economies of scale, starting in the 1980s, as smaller generation facilities became more economical. These shifts called into question whether a single generation provider would deliver lower-cost service than multiple providers in a competitive market. Competition also could offer incentives for generators to manage risks, lower costs, innovate and provide superior customer service. This set the foundation for industry reforms in the 1990s, when electricity markets began signaling investment decisions for much of the United States.

CONTACT

If you have questions regarding this subject, please contact Electricity Policy Manager Devin Hartman or Outreach Director Lori Sanders at the R Street Institute at 202-525-5717.