

Restructuring Electricity Supply

ELECTRICITY IS ESSENTIAL TO THE PRODUCTION OF almost all goods and services and so is vital to the public interest.¹ In addition, reliable electricity systems have become more important because businesses and households rely on electronic devices to perform an enormous range of tasks, both basic and advanced. Thus adequate, reliable, competitively priced electricity is essential for modernization, domestic growth, and international competitiveness—and is among the most urgent challenges facing developing and transition economies.

Until recently most electricity industries were vertically integrated monopolies owned by national, state, or municipal governments (Joskow 2003a). But since the early 1980s, when Chile began a radical restructuring and privatization program, more than 70 countries have introduced electricity reforms (Bacon and Besant-Jones 2001). And especially over the past decade, views have changed dramatically on how electricity should be owned, organized, and regulated (Newbery 2000a, 2001). Accordingly, there are numerous perspectives and lessons on the most important reform issues and best policy options.

A clear-eyed assessment is especially important now given the crisis with electricity reform in California (United States), the recent blackouts in Europe (Bialek 2004), and the challenges confronting electricity systems in several developing and transition economies. Events in California have alarmed policymakers around the world, slowing reform and possibly impeding the development of competitive electricity markets (Besant-Jones and Tenenbaum 2001; Joskow 2001). Some developing and transition economies that had planned reforms might

defer them. Others will not consider restructuring and deregulation until there is convincing evidence of their merits.

Background to Electricity Reform

AFTER DECADES OF STRUCTURAL IMMOBILITY IN THE ELECTRICITY industry, governments are allowing market forces to play a role in generation and supply. Structural change accelerated over the past decade and is now a global phenomenon. Although only a handful of countries have achieved substantive market liberalization, almost all have felt considerable domestic and international pressure to reform their electricity systems.

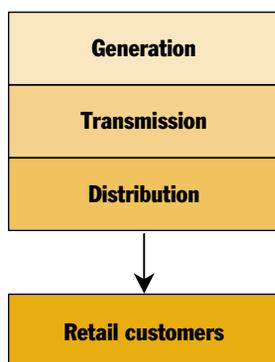
The Industry's Traditional Structure

The electricity industry has three components: generation, high-voltage transmission, and low-voltage distribution (figure 3.1). (In recent years, as a result of sector reforms, supply or retailing—power procurement, billing, and customer service—has increasingly been considered a fourth component.) A wide variety of technologies and primary energy sources are used to generate electricity. Nonrenewable sources include coal, petroleum, natural gas, and uranium; renewable sources include biomass and hydro, wind, solar, and geothermal power.

Historically, the electricity industry has had a monolithic structure, with a single entity owning generation and transmission capacity and performing all system operations. This entity transmits power to one or more distribution companies that hold exclusive rights to serve households and businesses in specific regions. In some countries distribution companies are independent entities with separate governance and legal structures, purchasing their power from the generation and transmission entity at regulated tariffs. In others there is common ownership of generation, transmission, and distribution systems. In most countries—except Germany, Japan, Spain, and the United States—these entities have been publicly owned (Joskow 1998a).

Electricity has unique physical and economic characteristics that limit the extent to which decentralized market mechanisms can replace vertical and horizontal integration (Joskow 2003a). Complementarities between generation and transmission result in significant economies of

Figure 3.1 Vertical Integration in Electricity



Box 3.1 Rationale for Structural Integration of the Electricity Industry

THE ECONOMIC RATIONALE FOR VERTICAL AND horizontal integration in electricity derives from characteristics of transmission networks and from operating and investment relationships between generation and transmission. A key attribute of a transmission grid is its ability to synchronize dispersed generating units into a stable network. This aggregation allows real-time substitution of production from facilities with lower marginal costs for production from facilities with higher marginal costs, increasing efficiency. It also improves reliability by providing multiple links between system loads and generating resources, and can economize on the reserve capacity required for a given level of system reliability.

Electricity generation and consumption need to be balanced continuously and almost instantly for a network to meet specific physical parameters (frequency, voltage, stability). Unlike other switched

networks, such as railroads or telecommunications, where routing in the physical delivery of products can be specified, flows in electricity networks are hard to control. A transmission network is largely passive and has few “control valves” or “booster pumps” to regulate power flows on individual lines. Electrons follow the path of least resistance, and control actions are limited to adjusting generation output and removing or adding transmission lines. Moreover, every action can affect all other activities in the grid: if the failure of a single element in the system (such as the shutdown of a generation unit or transmission line) is not managed properly, it can destabilize the entire electricity grid. Similarly, large swings in load at one node affect conditions at other nodes. Thus electricity requires careful, deliberate, systemwide coordination to achieve real-time balancing of supply and demand.

Source: Joskow (2000a).

scale and scope, which are the main reason the industry evolved with a vertically integrated structure (box 3.1). In most countries dispersed generators are also horizontally integrated into a single firm. Transmission and distribution are quintessential natural monopolies (although technological change is weakening this characterization).² Because they entail substantial, largely sunk fixed costs, competition would lead to wasteful duplication of network resources. Thus in most countries a single entity governs the transmission network for all or most of the country. Although economies of scale are not pervasive in generation, vertical integration between generation and the network elements of the natural monopoly limits competition in generation—even when numerous generating plants are connected to the network.

Other features that distinguish electricity from other network utilities limit the scope for competition or reliance on market mechanisms. Electricity supply is rigid by nature. Electricity cannot be stored economically because storage technologies—such as batteries and hydro-

electric pumps—are extremely inefficient. Thus electricity is the ultimate real-time product, with production and consumption occurring at essentially the same time. But because of physical constraints on production and transmission, achieving real-time balancing of supply and demand is difficult and requires intensive system coordination. Network congestion constrains the ability of remote generators to respond to the supply needs of a given area. Moreover, generating units have capacity constraints that cannot be breached without risking costly damage. As a result the amount of electricity that can be delivered in an area at a given time is limited and supply is highly inelastic—especially at peak times (Borenstein 2000).

The challenges created by electricity supply are exacerbated by the lack of flexibility in demand. Although technologies are available to enable real-time pricing, no electricity market makes significant use of them. So, few if any electricity customers pay real-time prices. Because demand is almost completely inelastic in the short run, little or no supply and demand balancing can be conducted on the demand side. Inelastic short-run demand and supply (at peak times), combined with the real-time nature of the market, make the electricity industry highly vulnerable to the exercise of market power.

The physical properties of electricity transmission imply that an imbalance of demand and supply at any location on the grid can affect the stability of the entire system. Thus the matching between a supplier and a customer is effectively part of the overall system balancing. Any mismatch could disrupt the delivery of electricity for all suppliers and consumers (Borenstein and Bushnell 2001). Because of electricity's inability to be stored, the varying demand for it, random failures in generation and transmission, and the need to continuously match supply and demand at every point in the system to maintain frequency, voltage, and stability, there is a need for real-time "inventory" to keep the system in balance. In theory the inventory problem could be resolved by market mechanisms with standby generators providing ancillary services in response to changing demand and supply conditions. But in practice such systems are difficult to design (Joskow 2003a).

These features have important implications for the design of efficient electricity markets and regulatory institutions. Simplistic approaches that ignored these attributes have led to serious problems for the public interest.

Pressures for Reform

The forces driving structural changes in the electricity industry differ between countries—especially between industrial and developing countries. In mature industrial countries pressure for change has grown with the emergence of excess capacity and from disillusionment with capital-intensive generation projects triggered by the oil crises of the 1970s. In developing and transition countries reforms have been driven by the poor operating and financial performance of state-owned electricity systems (with low labor productivity, poor service quality, and high system losses), lack of public funds for badly needed investments, unavailability of service for large portions of the population, and government desires to raise revenue through privatization (IEA 1999; Bacon and Besant-Jones 2001; Joskow 2003a).³ Reforms were also prompted—and facilitated—by technological innovation.

Excess capacity in industrial countries. For about 30 years after World War II, industrial countries experienced remarkably high and steady growth in demand for electricity. But in the 1970s this growth was interrupted, and it has never returned to its previous level. In an understandable response to that decade's oil shocks, industrial countries tried to reduce their dependence on oil for power generation. This shift increased interest in options such as nuclear power and large, supercritical coal-fired generating stations.⁴ At the same time, budget pressures, high inflation, and attempts by state enterprises to contain the prices of their goods (part of strategies to counter inflation) squeezed electricity profits, delayed investments, and undermined confidence in previously smooth-running planning systems.

Still, the resulting circumstances were fairly benign. The development of high-efficiency combined-cycle gas turbines weakened the case for closely integrated generation and transmission systems based on economies of scale. The rapid development of gas pipelines and increasing availability of cheap gas in Western Europe and the United States made combined-cycle gas turbines more attractive than existing technologies. Dense, well-integrated electricity grids, an abundance of power stations, and excess capacity made competition between generating companies feasible and attractive.

The United Kingdom began reforming and privatizing electricity in 1990, showing that it was possible to replace state-owned, vertically integrated monopolies with privately owned, unbundled, and regulated companies. The European Union soon started pressing for electricity liberalization in its member states, and its Electricity Directive required open access and liberalized markets starting in 1998.

Similar efforts were under way in North America. In the United States reform has been complicated by the need to ensure that stranded assets are compensated, though initially there was great confidence that a deal could be struck that would benefit all parties.⁵ Then, just when the European Union was pressing for further reform, California's recent electricity crisis shook political confidence in the liberalization agenda.

Need for investment in developing countries. Many developing countries are at a stage of economic development where demand for electricity increases rapidly, requiring enormous investment. Between 1999 and 2020 global electricity consumption is projected to increase by 2.7 percent a year, but in the developing world the increase is projected to be 4.2 percent a year (table 3.1).

Table 3.1 Net Electricity Consumption in Industrial and Developing Countries, 1990–2020

(billions of kilowatt-hours)

Country group	1990	1999	2005	2010	2015	2020	Average annual change, 1999–2000 (percent)
Industrial countries	6,385	7,517	8,620	9,446	10,281	11,151	1.9
United States	2,817	3,236	3,793	4,170	4,556	4,916	2.0
Eastern Europe and former Soviet Union	1,906	1,452	1,651	1,807	2,006	2,173	1.9
Developing countries	2,258	3,863	4,912	6,127	7,548	9,082	4.2
Asia	1,258	2,319	3,092	3,900	4,819	5,858	4.5
China	551	1,084	1,523	2,031	2,631	3,349	5.5
India	257	424	537	649	784	923	3.8
Other	450	811	1,033	1,220	1,404	1,586	3.3
Central and South America	449	684	788	988	1,249	1,517	3.9
World total	10,549	12,832	15,183	17,380	19,835	22,406	2.7

Note: Data for 2005–20 are projections. Totals for industrial and developing countries include countries and regions other than those listed.
Source: EIA (1999, 2002b).

Box 3.2 Power Shortages in the Philippines

IN THE PHILIPPINES IN 1992, EXCESS DEMAND WAS EQUAL TO NEARLY half of system capacity. Brownouts lasted up to 10 hours a day. Shopping malls were ordered to reduce their hours of operation by 2 hours, and industrial areas faced 12-hour blackouts three times a week. Of 512 international firms that had or planned to open their Asian headquarters in Manila, 123 closed their operations and 226 cancelled their registrations.

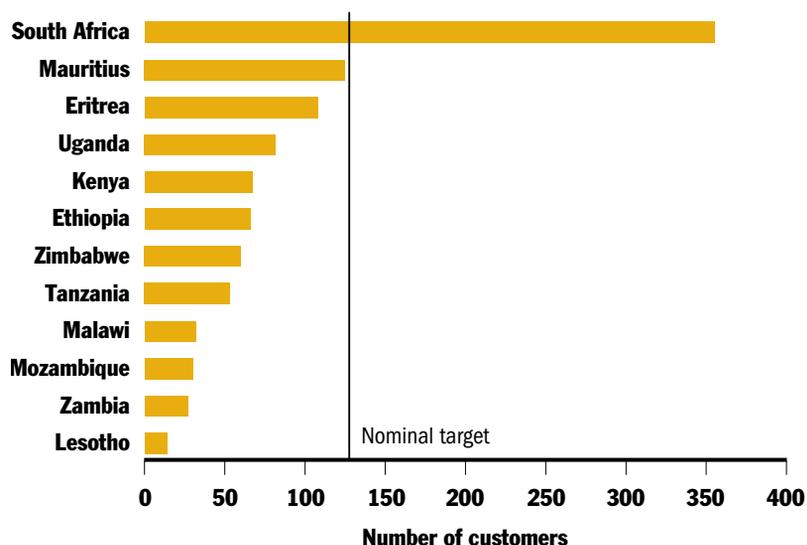
Source: Henisz and Zelner (2001).

Electricity systems are under stress in many developing countries. The balance between demand and supply is tight, and lack of spare capacity often leads to blackouts (box 3.2). Thus significant investments are needed in generation, transmission, and distribution. But the governance structure in the sector—typically vertically integrated, state-owned, and centrally planned—is poorly suited to mobilizing the long-term capital needed for adequate, reliable electricity supply.

In the early days of rapid growth and young plants, prices could be set at cost recovery levels and even allowed to fall due to the rapidly decreasing costs resulting from economies of scale and new technologies. Thus integrated, state-owned electricity systems performed reasonably well—but only at first.

Over time, especially as inflation and budget pressures increased, the margin between revenues and costs was squeezed. In most developing countries electricity prices stopped covering costs and were far below the long-run incremental costs of system expansion. Such pricing made it difficult to maintain facilities and finance new investments. As a result systems became inadequate and unreliable, and supply shortages increased. Moreover, underpricing for favored groups became more noticeable politically, yet harder to reverse. Political interference also led to management deterioration and extraordinarily high excess employment (figure 3.2). Lack of effective monitoring led to theft and losses that further undermined the sector's financial sustainability.

Technological innovation. Recent technological advances have dramatically altered the cost structure of electricity generation. They are

Figure 3.2 Customers per Electricity Employee in Selected African Countries, 1998

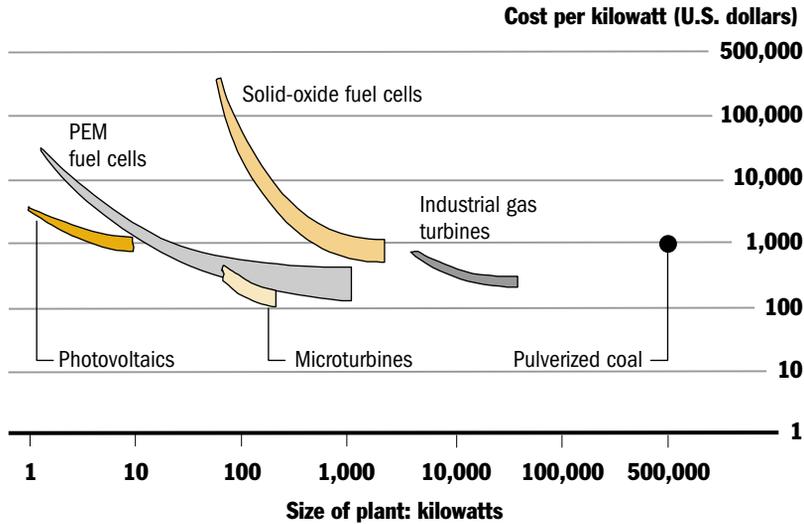
Source: Kerekezi and Kimani (2001).

also changing the network economics of the electricity grid in both industrial and developing countries.

From the start of the 20th century until the early 1980s, technological developments led to larger and more efficient fossil-fuel power plants built farther and farther from cities and factories. But in recent years technological improvements in gas turbines and the development of combined-cycle gas turbines have recast economies of scale in electricity, reversing a 50-year trend toward large, centralized power stations (Bayless 1994; Casten 1995). Combined-cycle gas turbines can be brought online faster (within 2 years) and at more modest scale (50–500 megawatts) than coal or nuclear plants (5–10 years and 1,000 megawatts). Aero-derivative gas turbines can be efficient at scales as small as 10 megawatts (Balzhiser 1996).

Although natural gas and light oil distillates are the preferred fuels for gas turbines, a wide variety of low-calorific fuels have also been used successfully. (For example, the Kot Addu plant in Pakistan has accumulated 60,000 hours of successful operation burning heavy oil and naphtha, and the Paguthan plant in India has accumulated 19,000 hours.) Thus gas turbine technology is of growing importance even for

Figure 3.3 Projected Costs of Small-Scale Electricity Generation Technologies, 2000–15



Source: "The Dawn of Micropower," *The Economist*, 5 August 2000.

developing and transition economies that lack natural gas resources (Taud, Karg, and O'Leary 1999).⁶

Electricity utilities are already using small-scale generators to meet peak demand and serve other purposes. But small generators can also be used to bypass utilities. And when demand is sufficient to realize economies of mass production, the capital costs of small-scale generating units will likely fall. In the 1980s wind generators cost \$4,000 per kilowatt installed, but today cost just \$1,250 per kilowatt. Thus it might soon be possible to add efficient capacity of 1–10 megawatts—the range needed for many factories, large housing developments, and other institutions (figure 3.3).

But while small-scale generation holds considerable promise, it is not yet competitive with centralized power systems. A number of factors affect the competitive balance between centralized and distributive generators, including differing regulations, efficiencies, fuel prices, capital costs, and environmental externalities.⁷ Relative to large centralized generation, capital costs per kilowatt are about twice as high and efficiencies about half for distributive generation.⁸ For example, gas-fired central plant generating facilities have efficiencies of 48–52 percent—

Efficient fuel cells could offer a way to generate power at the consumer site—causing transmission and distribution to cease being natural monopolies

twice that of gas microturbines. Moreover, gas-fired distributive generators are likely to pay higher prices for inputs because large central stations can buy their gas in bulk at much lower rates. And because of their lower efficiency, small-scale technologies emit far more carbon dioxide than do efficient combined-cycle gas turbines. On the other hand, distributive generation leads to lower network costs (Lee 2003).

In most developing countries there is considerable uncertainty about the reliability of electricity systems. The proximate cause is the inadequate response to increased demand for electric power through generation, transmission, and distribution upgrades and expansions. What role (if any) distributive generation will play in the baseload electricity market—and thus in resolving the reliability problem—is hard to predict. If gas microturbines and other small-scale generation technologies significantly reduce their costs and improve their efficiencies, they might have a considerable impact on the structure of electricity markets.

Having many small generators operating at or close to load would reduce reliance on transmission and even distribution facilities. New electricity storage technologies would have the same effect (Thomas and Schneider 1997). Although small generators are not expected to displace large thermal plants, at least in the foreseeable future, new generation capacity will likely come from smaller units. Distributive generation can play an increasingly important role in providing ancillary services such as emergency backup power and voltage support, increasing system reliability. In developing countries—where centralized supply has yet to reach 1.8 billion people—small-scale, modular generation close to the point of consumption might be a more realistic and even economical option.

This new industry model would enhance the ability of gas pipelines to compete with electricity transmission networks. Having small generators delivering power at or near the point of consumption would cap the prices that other generators and transmitters could charge, especially to large industrial users. Indeed, the mere threat of bringing on-line gas turbine capacity would constrain the behavior of a transmission monopolist (Baumol, Panzar, and Willig 1988).

Small-scale generation is already changing the service landscape in several developing countries where there is no regulation or where entry to the sector is formally allowed. In Yemen small generators supply rural towns and villages not served by the public utility. Operations range from individual households generating power for themselves and a few neigh-

Box 3.3 Opening the Electricity Market—Photovoltaic Systems in Kenya

WHEN A UTILITY FAILS TO PROVIDE SERVICE TO many households, allowing entry by entrepreneurs can fill the gap. Kenya's electricity utility fails to provide connections to more than 98 percent of the rural population, so households have started turning to alternative systems. Between 1982 and 1999 the market for photovoltaic units grew into a \$6 million a year industry.

In the 1980s the demand for photovoltaic systems came from nongovernmental organizations installing demonstration systems in schools and missions, and from off-grid community leaders and

middle-income households. Photovoltaic retailers realized that continued sales required expanding the market. The availability of smaller, cheaper systems helped on the supply side. Local marketing emphasized the technology's many uses—from lighting to television—raising demand. In the late 1990s local entrepreneurs sold more than 22,000 modules a year. Competition lowered the retail price from \$100 a module in 1990 to \$65 in 1998. The introduction of hire-purchase options has further extended the market. Since 1990, 60 percent of the 2.5 megawatts in photovoltaic sales has been to households.

Source: Hankins (2000).

bors to units supplying up to 200 households. Although these small electricity suppliers have been criticized for being inefficient and expensive, the alternative for Yemeni households is not service by the utility but no service at all—or far less efficient, even more costly alternatives such as dry cell batteries (Ehrhardt and Burdon 1999; Tynan 2002).

In Kenya, because the rural population is so sparse, expanding coverage from the national power grid would be extremely costly. So, some rural households are being served by private companies offering a different technology: photovoltaic systems (box 3.3). Since 1990 more than 2.5 megawatts of photovoltaic capacity have been sold, providing power to more than 1 percent of the country's 25 million rural inhabitants (Hankins 2000). Standalone photovoltaic systems are also being used in Brazil, India, Namibia, Senegal, South Africa, and Thailand—powering water pumps, streetlights, lanterns, and telecommunications relay stations.

Addressing the Problems of State Ownership

UNDER STATE OWNERSHIP, MANAGERS AND POLITICIANS favor underpricing to stimulate demand and secure political support. Excess demand signals a need for investment, which

managers desire and politicians view as a sign of development. Before the reform era, international donor agencies were happy to fund investments in power because electricity utilities were a visible sign of technology transfer and had high social returns. Insufficient power had high costs even in developing countries. But inflationary pressures caused tariff agreements to be abandoned and further encouraged low prices for public electricity. As a result real electricity prices fell, as did profits—and hence utilities' ability to finance their investments. One problem with capital-intensive electricity utilities is that their operating costs (mainly fuel) are only about half their total costs, so if they underprice services they can still cover their operating costs.

A 1989 survey of 360 electricity utilities in 57 developing and transition economies found that the average annual return on revalued net fixed assets was less than 4 percent, well below the 10 percent target normally set by donors. In 1991 these utilities financed just 12 percent of their investment requirements, and revenue covered only 60 percent of power sector costs. Underpriced electricity imposed a fiscal burden of \$90 billion a year in the early 1990s, or 7 percent of government revenues in developing countries—larger than required power investments of about \$80 billion a year. Moreover, technical inefficiencies caused nearly \$30 billion a year in economic losses (Besant-Jones 1993; World Bank 1994b; Newbery 2001).

These outcomes occurred despite several decades of studies on tariff reforms, agreements to improve pricing, and reports arguing that underpricing electricity was inefficient, fiscally harmful, and distributionally unjust. Underpricing was also the main cause of underinvestment in developing countries (box 3.4). Lacking an alternative source of investment, countries persuaded donors to continue support, reducing incentives to make politically unpopular pricing decisions. When Chile, followed by the United Kingdom and other countries, showed that privatization works, it seemed like the obvious solution to the problem—introducing financial prudence, competent management, and operational efficiency while relieving governments of heavy investment costs.

In competitive markets where private owners pursue profits, there are incentives for efficiency and mechanisms for adequate investment. The problem with electricity supply is that transmission and distribution are natural monopolies and cannot be operated competitively. The

Box 3.4 Underpricing Undermines Electricity Expansion in Zimbabwe

THE MAIN CASUALTY OF ZIMBABWE'S FAILURE TO RAISE ELECTRICITY tariffs to cost-reflective levels was the country's electricity development plan, which sought to expand existing power stations and add new ones. Frequent changes of ministers of energy and weak policy commitment to remunerative tariffs undermined efforts to privatize the Hwange power station and attract private participation in a plant planned at Gokwe North. Foreign investors abandoned privatization and expansion projects in 2000, mainly because of the government's failure to realign prices with long-run marginal costs.

Source: Mangwengwende (2002).

logical solution is to separate potentially competitive generation and supply (or retailing) from the natural monopoly networks. Generation and supply can then operate in competitive markets, and the natural monopolies regulated to imitate the effects of competition.

The crucial question is how to introduce competition into generation (and supply). The standard answer is that competition requires a market, so generation needs a wholesale electricity market organized as a power exchange or a pool. That model works well if there is adequate generation and transmission capacity and enough independent generators to ensure competition. But such conditions are demanding and may not be sustainable. Although many electricity industries have been restructured successfully, they all started with substantial spare capacity. As time passes, if prices remain low because of strong competition, entry will be unattractive and capacity will become scarce. In addition, generators may want to merge to increase their market power and deter additional entrants.

Thus this approach should be pursued with caution. It may be sustainable if there is sophisticated regulation of competition and regulators can find a way to ensure adequate investment in transmission. But California's recent experience is a reminder that sophisticated regulation is a scarce commodity even in advanced industrial countries.

Options for Restructuring Electricity Markets

Electricity markets can be structured in four ways, reflecting varying competition and customer choice:

- *Monopoly*—the traditional status quo, where a single entity generates all electricity and delivers it over a transmission network to distribution companies or costumers.
- *Single buyer*—where a single agency buys electricity from competing generators, has a monopoly on transmission, and sells electricity to distributors and large power users without competition from other suppliers.
- *Wholesale competition*—where multiple distributors buy electricity from competing generators, use the transmission network to deliver it to their service areas under open access arrangements, and maintain monopolies on sales in their service areas.
- *Retail competition*—where customers have access to competing generators, directly or through a retailer of their choice, and transmission and distribution networks operate under open access arrangements (table 3.2).⁹

Given the unique economic characteristics of the electricity industry—especially the need for coordination between generation and transmission, and the difficulty of replicating vertical relationships with market mechanisms—the monopoly option has some appeal. In theory an integrated company could minimize the cost of meeting demand at each point in time through optimal dispatch of its power stations, taking into account systemwide transmission constraints and losses. In the long run it could exploit the investment relationships between generation and transmission and undertake investments based on systemwide planning.

Table 3.2 Options for the Structure of Electricity Markets

Feature	Monopoly	Single buyer	Wholesale competition	Retail competition
Competing generators?	No	Yes	Yes	Yes
Choice for retailers?	No	No	Yes	Yes
Choice for customers?	No	No	No	Yes

Source: Hunt and Shuttleworth (1996).

But these benefits will likely be small relative to those that come from promoting competition in generation: lower construction and operating costs, incentives to close inefficient plants, and better pricing (Joskow 2000a). Because the monopoly option does not allow for competition in generation, it is largely a straw man today: no one would choose it to promote the public interest. The three other options progressively increase competition and market-oriented decisionmaking in the electricity industry and its vertical relationships. Most reform programs are designed to move from monopolies to wholesale and retail competition. Complex policy issues arise when determining whether the single-buyer option is a sensible transition to wholesale competition and the stage at which retail competition is appropriate and feasible. (The single-buyer option and wholesale competition are analyzed in more detail below.)

Though the options vary, there is wide agreement on the basic architecture for electricity restructuring. The standard reform model separates transmission, distribution, and system operations from the competitive activities of generation. Wholesale and retail competition is the standard prescription, with a regulatory agency setting tariffs for transmission and distribution (Joskow 2003a) and market entrants building new generation capacity with nondiscriminatory access to the grid and customers. There is less agreement on the sequencing of electricity reforms. In countries where underpricing is a serious problem, privatizing the distribution monopoly might be considered a necessary first step to promote the tariff adjustments required to revive sector performance (Newbery 2001). But the tight balance between demand and supply in many developing countries (and so the need to ensure adequate generation) and the dramatic technological changes that have made generation structurally competitive would argue for privatizing generation first.

Most of the downward pressure on prices from electricity restructuring comes from promoting efficiency at the firm level through wholesale competition. The issue of providing “customer choice” through retail competition has received considerable attention in the popular discussion of electricity reform. But there is considerable debate about the magnitude of the price benefits that electricity retailers are likely to bring, especially to residential and small commercial customers. Retailing costs are small and so reducing them by competition would lead to small customer savings. Also, the opportunities for price

competition are likely to be limited and retail competition may be socially costly because of increases in marketing, advertising, settlement and transactions and other associated costs (Joskow 2000b). Thus it is asserted that only in very few cases have residential customers benefited much from retail competition. Still, others argue that retail competition can lead to better informed decisions by both suppliers and customers (what types of service to supply and what to consume) and help identify the best suppliers and (indirectly) the best generators. It can also provide better information about the relation of costs to prices, increase the political and economic pressure for improved cost allocation, and reduce the scope for government and/or regulators to favor particular interest groups (Littlechild 2000).

Privatizing Distribution

In the absence of reforms, most electricity systems suffer from unbalanced tariffs, inadequate revenues (often associated with failure to collect bills and reduce theft), excessive costs, and inefficient or insufficient investment. For example, cash collection (cash collected relative to the amount billed) averages just 46 percent in seven members of the Commonwealth of Independent States (Armenia, Azerbaijan, Georgia, Kyrgyz Republic, Moldova, Tajikistan, Uzbekistan), and commercial losses (unbilled consumption) exceed 20 percent. Power industries in southeastern Europe face similar problems (table 3.3).

The logical place to address revenue shortfalls is at the distribution and supply end (usually combined), which collects revenue from customers. The best way to start and sustain pricing and related reform is to separate the distribution monopoly from the rest of the industry, privatize it, and subject it to price or revenue cap regulation.

A related question is whether to separate the supply function from distribution, or at least signal that this will eventually happen. This partly depends on whether a supply franchise for small customers (those using less than 1 megawatt or possibly 100 kilowatts) is expected to continue. If so, the distribution company is the natural supplier to the franchise market, and the main requirement is to ensure that suppliers have nondiscriminatory access to the distribution network and meters. Still, the case for liberalizing supply is weak in industrial countries and even weaker in developing countries (see below).

Table 3.3 Cash Collection and Commercial Losses for Electricity Companies in Southeastern Europe, 2000*(percent)*

Country	Cash collection	Commercial losses
Albania	60	40
Bosnia and Herzegovina	75	25
Bulgaria	85	10
Croatia	100	5
Macedonia, FYR	60	—
Moldova	55	35
Romania	45	5
Serbia and Montenegro	60	20

— Not available.

Source: Broadman and others 2003; Kennedy, Fankhauser, and Raiser (2003).

Private Participation in Generation

The private sector can become involved in generation in two ways. The most common way is for the government to sell a controlling share in generation companies, possibly retaining nuclear power stations, major multiuse hydroelectric dams, or both. If generation is to be privatized, the state electricity company must be split into a sufficient number of competing companies. The second way is for the government to invite tenders from independent power producers interested in supplying the (preferably restructured) state electricity company. This approach introduces new private investment into the industry yet requires only modest reform and restructuring. Private investors might be reluctant to enter such markets, however, unless the government gets out of the generation business.

In both cases the logical first step is to separate transmission from generation and create conditions for regulated third party access to transmission. Transmission will also need to be regulated, under principles similar to those for distribution. But fewer problems are likely if transmission remains publicly owned (at least for a transition period).

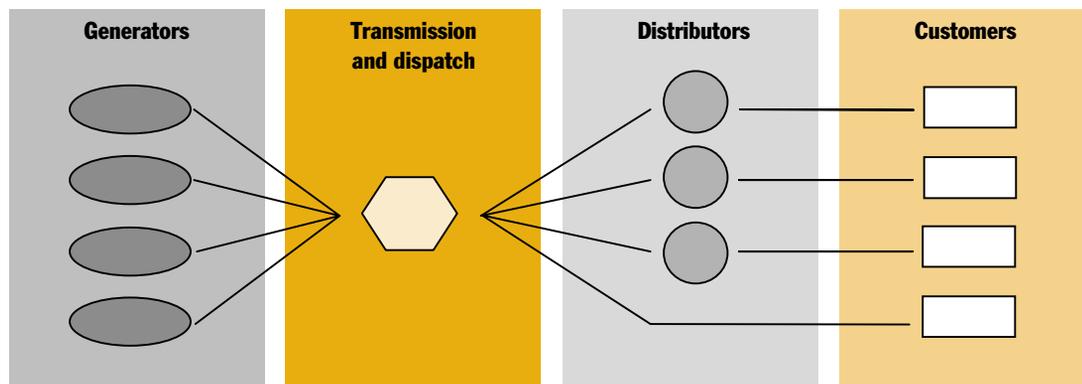
The arguments for separation (preferably ownership separation) of transmission from generation are standard. A transmission company with ownership stakes in generation will likely favor its generation over that of other owners. This may not be a serious problem if all new gen-

eration capacity is put up to auction and the transmission company acts as the single buyer. But far more serious problems arise if the intention is to create a competitive, less regulated wholesale market with free and contestable entry (see below for a discussion of such problems in Chile).

Two quite different approaches are used to introduce competition into generation. Under the single buyer approach the transmission company (which may be vertically integrated with generation and even distribution and supply) buys all publicly generated electricity.¹⁰ Competition occurs through periodic tenders for new generation capacity, with the winners signing long-term power purchase agreements with the single buyer. The second approach creates a wholesale spot market (pool) or power exchange where generators sell directly to suppliers, final customers, or both.

Single buyer model. The single buyer model has evolved under a variety of organizational forms. It may simply comprise the state-owned, vertically integrated utility. Alternatively, the national utility might be split into generation, transmission, and distribution companies, with the transmission and dispatch facilities remaining under public ownership and the newly formed transmission and dispatch entity buying electricity from generators and selling it to distribution companies at regulated tariffs (figure 3.4; Lovei 2000). The model may further entail

Figure 3.4 The Single-Buyer Model for Electricity



Source: Lovei (2000).

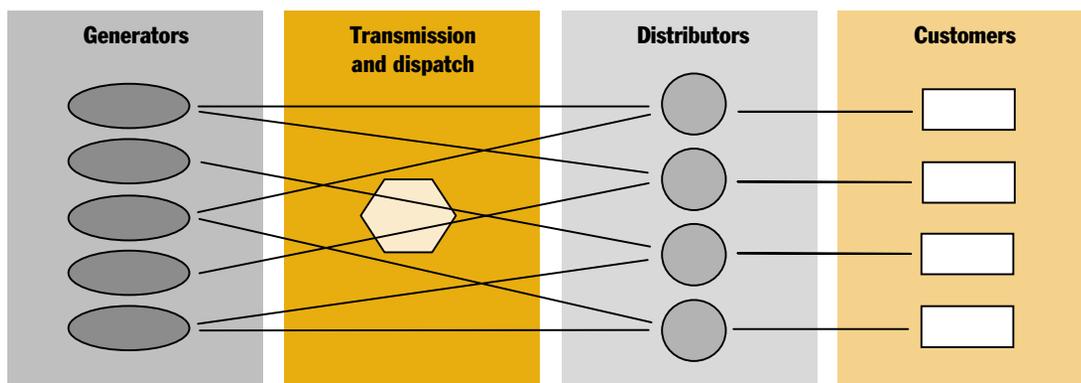
the dispatch company being unbundled from the single buyer entity. And in its completely unbundled form, the transmission company is also separate from the single buyer entity.

In the model's extreme form the single buyer buys all energy and capacity in the market, is the sole authorized seller of electricity (ruling out competitive supply), decides what, from whom, and how much to buy, and assumes most of the credit and market risk (active single buyer). Another form of the centralized buying model entails an entity acquiring a large part of the energy and capacity (and selling it to distribution companies at regulated tariffs) but not being the only buyer in the system (principal buyer). Finally, a relatively new model involves the buyer acting as an aggregator and procurement coordinator, responsible for the procurement of energy to distribution companies. But the buyer does not take the initiative on how much and from whom to buy, and assumes no credit or market risk (passive buyer; Barker, Mauer, and Storm van Leeuwen 2003).

The single buyer model provides a way for independent power producers to compete for long-term power purchase agreements—a precondition for private investment in generation in electricity sectors with few reforms. The model can also work if existing power stations are sold to private generation companies.

Since the early 1990s many countries in Asia, the Caribbean, Central America, and Eastern Europe—and to a less extent the Middle East and Africa—have adopted variations of the single buyer model. Competitive long-term power purchase agreements expedite private investment to meet growing electricity demand without the need for drastic industry restructuring. Indeed, the tendering process is sometimes just grafted onto a vertically integrated and otherwise unreformed electricity entity (as with Malaysia's Pusat Tenaga), which is probably a good model for small developing countries.

Efficient power purchase agreements specify availability payments (the amount charged for each kilowatt of capacity available for dispatch, possibly with different rates at different times of the year) and energy payments (linked to the fuel price, per megawatt generated). Given these and other technical parameters, the single buyer can determine which tender offers the best value or lowest cost. Thus competitive tendering can considerably cut the cost of generation. In Hungary, for example, tenders to build new power stations nearly halved average production costs.

Figure 3.5 The Wholesale Competition Model for Electricity

Source: Lovei (2000).

Wholesale competition. With wholesale competition, local distribution companies retain their exclusive service territories and buy power from competing generators (figure 3.5). Customers cannot choose their suppliers, but users consuming more than a certain volume of power may be able to contract with generators. Though many countries have only a few hundred or few thousand high-volume users, they account for a large share of demand. By allowing wholesale customers to buy cheaper power from alternative suppliers and by providing more customers for independent power producers, this option makes the market more competitive and dynamic than does the single buyer model.

Several prerequisites must be met for wholesale electricity markets to succeed (Wolak 2003). First, buyers must have a spot market or power exchange (where buying and selling occurs) and a forward market (where market participants can negotiate contracts). Forward contracts mitigate the risk of volatile spot prices and encourage suppliers to bid aggressively in the spot market. California's recent electricity crisis shows the importance of load-serving entities purchasing a substantial portion of their energy needs in the forward market—at least a year before delivery.

Second, a competitive wholesale market requires a sufficient number of unaffiliated suppliers. Competitive entry will be inhibited if a single supplier dominates the market. Third, there is a need for active participation by as many customers as is economically feasible in both long-term and short-term markets. Allowing wholesale electricity buyers to

enter long-term purchasing agreements with suppliers facilitates financing of new generation capacity. In the short-term market, suppliers will be much less likely to exercise market power if customers can alter their consumption in response to short-term price signals.

Fourth, wholesale electricity markets require an economically reliable transmission network—that is, one with adequate capacity so that each location on the network faces sufficient competition among distant generators, to preclude localized monopoly power. For transmission prices to encourage efficient use of generation and transmission resources, they must reflect generators' full impacts on transmission costs, including system congestion, stability, and reliability. In addition, the system operator should ensure the stability of the system's frequency and voltage.

Finally, there is a need for a credible, effective, fast-acting regulatory mechanism to deal with flaws in market design and encourage efficient behavior by market participants. This is especially imperative when wholesale electricity markets are established without all of the essential prerequisites just described.

Contrasting the single buyer model and wholesale competition.

The single buyer model is often the preferred approach for a variety of technical, economic, and institutional reasons:

- It promotes rapid investment and expansion by shielding the financiers of generation projects from market risk and retail-level regulatory risk.
- It facilitates system balancing (the balancing of differences between the planned and actual output of individual generators and between the planned and actual loads of individual distributors).¹¹
- It provides the necessary scale and expertise to efficiently contract for energy, power, and ancillary services and improve system reliability.
- It can be implemented quickly because it does not require significant changes in the operating culture or in sector policy (Lovei 2000; Barker, Mauer, and Storm van Leeuwen 2003).

But the single buyer model also poses considerable risks, and in practice has experienced several problems. First, if the single buyer also owns generation, it may select bids from its generation subsidiary or

bias competition in favor of it. Incumbent single buyers are loath to face the test of competition—which may reveal high operational costs—and well placed to impede entry by imposing unreasonable conditions. As a result potential generators may be reluctant to incur the costs of preparing a bid, reinforcing the power of the incumbent buyer and defeating the purpose of opening generation to outside investors.

Second, in its standard form (active single buyer) the model concentrates all financial risk in the hands of a single agent. If this state-owned agent is unable to meet its obligations to generators, the government is expected to step in (an expectation formalized in a guarantee agreement). Thus power purchase agreements under the single buyer model create a contingent liability for government that can affect its creditworthiness. Effectively, taxpayers or customers—not investors—bear all the risk.

Third, investments in generating capacity are not driven by market incentives, but rather by bureaucratic preference. Decisions about expanding capacity are made by government officials who do not face the financial consequences of their actions. In fact, governments have often abandoned least-cost expansion alternatives because of political reasons, expediency, and outright corruption.

Fourth, the single buyer model weakens the incentives of distributors for effective demand forecast and procurement, and for collecting payments from customers. The state-owned single buyer is often politically constrained and reluctant to take action against delinquent distribution companies. Thus the lack of direct contracts between generators and distributors inevitably undermines payment discipline. When paying and nonpaying distributors are treated alike, their incentives for efficient performance are clearly weakened. These distorted incentives are not easy to fix.

Fifth, the standard single buyer model involves a state-owned entity with weak incentives to minimize energy procurement costs, and it might be susceptible to political interference for the same reasons as the former state-owned electricity industry (Wolak 2003). Thus the single buyer model is likely to allow governments to influence the dispatch of generators and the allocation of revenues among them. In Poland and Ukraine coal miners were able to pressure governments to give special treatment to coal-fired generating plants (Lovei 2000).

Finally, the single buyer model tends to be self-perpetuating because of its excessively rigid contract structure. It risks stranding contracts that complicate further restructuring. Thus it increases the likelihood

that under pressure from vested interests, governments will delay further electricity reforms.

Bid-based versus cost-based dispatch and pricing. Many developing and transition economies lack some of the features required for competitive wholesale electricity markets. First, more than 100 countries have less than 1,000 megawatts of installed capacity—so unless there are strong connections to neighboring countries, the potential number of independent suppliers might be too small to support a competitive market (Besant-Jones and Tenenbaum 2001). Moreover, many medium-size and large countries have not undertaken sufficient horizontal restructuring in generation to mitigate problems of market power. Second, transmission networks are often poorly suited to wholesale competition. And third, most developing and transition economies have had a hard time establishing effective, credible regulation.

Under these circumstances a bid-based short-term (spot) market, where generators submit supply curves (indicating the quantity of energy they are willing to provide as a function of price) or multipart bids, might have disadvantages. The most obvious ones are the potential exercise of systemwide market power due to insufficient competition in generation or of local market power due to transmission bottlenecks in specific areas. If either outcome occurs, prices will likely be well above the marginal cost of the most expensive generator in the market (for systemwide market power) or in the specific area (for local market power). Thus potential market power problems must be carefully analyzed before a bid-based short-term market is introduced. If these problems are significant, the new market should be accompanied by strategies that mitigate them. Creating such strategies is a challenge even for experienced regulators.

Another disadvantage of a bid-based short-term market is the high start-up cost of the required real-time metering equipment, information technology, bidding protocols, and market-making and settlement software. For example, establishing California's spot market for electricity cost \$250 million. Even a small bid-based real-time (or near-real-time) market entails significant up-front costs (Wolak 2000).

Thus in many if not most developing and transition economies it might be unwise to establish bid-based dispatch. A safer strategy might be to pursue, at least initially, a cost-based spot market where generators are dispatched based on their marginal production costs—so the

marginal cost of the last unit called to meet demand determines the market clearing price. Almost every country in Latin America uses regulated unit-level costs to dispatch electricity and set prices (Colombia is an exception).

Cost-based spot markets offer several advantages. They:

- Ensure economically efficient dispatch (assuming generators are truthful in revealing their production costs).
- Make it harder for generators to exercise market power (because they must bid their regulated costs) and so avoid the time and expense of developing tools to mitigate it.
- Are easier to implement because they build on mechanisms that were in place prior to reforms and avoid the start-up costs of real-time bid-based systems.

By constraining the exercise of market power, cost-based mechanisms also reduce short-term variation in electricity prices. Lower volatility cuts costs for suppliers and load-serving entities because there is less uncertainty about prices over the duration of forward contracts (Wolak 2003).

But cost-based dispatch also has disadvantages. First, it does not eliminate the incentives or ability of suppliers to exercise market power (Arizu 2003). Suppliers may try to inflate their estimated or actual production costs, so the exercise of market power simply takes a different form. Thus an administrative procedure is needed to determine whether suppliers' input costs are prudent, which requires careful monitoring of fuel and other input markets. In many developing and transition economies, however, auditing is weak.

Second, cost-based dispatch offers a simulated spot market for electricity, not a real market. The price signals it provides to market participants are not as powerful as those in bid-based spot markets. For example, in a bid-based market the owners of hydroelectric units raise the price of their electricity if they anticipate water scarcity. In response, fossil fuel units will likely run more intensively much sooner, reducing the likelihood of electricity shortages.

Restructuring Generation and Transmission

Before the reform era, many countries had a number of separate distribution companies organized on a regional basis (except in very small

countries), but it was common for transmission to be vertically integrated with generation. There are good reasons for this setup:

- The location of new generation needs to be coordinated with the construction of needed transmission lines.
- Central dispatch is standard, and also requires close coordination between the transmission operator and individual power stations. Stations need to be brought on line in merit order—with the cheapest stations providing base load, followed by stations with higher avoidable costs providing mid-merit and peaking power—but the transmission operator must ensure that transmission lines are not overloaded. These transmission constraints may require the operator to dispatch stations out of merit order.
- The transmission operator needs to obtain ancillary services to maintain system stability, and so needs to be able to call on or instruct stations to provide these services at short notice.

These coordination benefits can still be obtained when generation is unbundled from transmission, and any small loss in synergies should be more than offset by the increased efficiency that results from competition in generation. Moreover, the sharper focus that a separate business provides can foster considerable improvements in transmission companies.

Central dispatch can be maintained, and the transmission operator will still need to obtain and provide ancillary services through contracts, tenders, or spot purchases. The main problems to resolve involve planning new transmission lines and ensuring that new generation plants are located efficiently. A variety of models are available, and their lessons are being studied carefully (IEA 1999). Whichever one is chosen, charges for using the transmission system need to be set at a level that finances network expansion (if necessary not out of current cash flow, but out of borrowing secured on future revenues from the investment). Transmission charges may differ to encourage generators to locate efficiently, though this may also be achieved through the capital charge for connection to the system.

The difficulty of setting and regulating efficient transmission charges provides one of the strongest arguments for unbundling transmission from generation. Otherwise the incumbent transmission operator will devise charges (particularly connection charges) that favor incumbent generators and disfavor entrants, raising their costs and allowing exist-

ing generators to set higher wholesale prices. Thus this unbundling is among the most important steps in electricity restructuring and reform.

Restructuring generation. When generation is unbundled from transmission, it needs to be restructured into independent companies—with revenue security if these are to be privatized. If the remaining transmission company is to become the single buyer, inheriting existing power purchase agreements with independent power producers, and if the generation companies are to be sold, they will need comparable and suitable power purchase agreements. This approach has been favored by transition economies in Central Europe as a means of financing refurbishment, and has both risks and benefits. If the aim is to create a fully liberalized wholesale market, additional steps are required.

In some cases the transmission company or its predecessor generation and transmission company may have power purchase agreements with recently created independent power producers. If the transmission company has been operating as a single buyer, it may acquire long-term purchase agreements even if the generation companies remain state-owned (box 3.5). In either case it is important to decide whether and

Box 3.5 Stranded Power Purchase Agreements in Poland

POLAND'S ELECTRICITY INDUSTRY WAS RESTRUCTURED AND UNBUNDLED in 1990, and by the end of 1993 consisted of 18 power plants, 24 combined heat and power stations, 33 distribution companies, and 1 transmission company, Polskie Sieci Elektroenergetyczne, which acts as a single buyer (and retains much of the expertise of the previously integrated power company). The generation companies had to borrow at high interest rates to finance refurbishment and pollution clean-up. This investment was secured against 24 long-term power purchase agreements with the transmission company, covering two-thirds of supply. These agreements, many of which are effectively stranded contracts, greatly complicated efforts to prepare the industry for privatization.

Source: Newbery (2001).

how to renegotiate these agreements and what contract arrangements should be put in place for new generation companies.

Ownership of the transmission grid. The economic and technological characteristics of generation, as well as the need for significant new investment, make a strong case for its privatization. Similarly, privatizing and regulating distribution companies is important for establishing sensible electricity prices and hence allowing generators to be paid viable prices. But there is much less agreement about the importance of privatizing transmission and the speed at which the process should be completed (Bushnell and Soft 1997).

Many countries prefer to keep their transmission grids under public ownership (just as they often prefer to keep distribution companies under municipal or regional ownership). Some of these countries have mature networks that require little expansion and account for a small part of the final price of electricity. But in many developing countries strengthening the transmission grid may be a top priority, and efficient management of its expansion is critical to the costs of delivering power to final customers.

The wholesale electricity market's design and operation will determine the industry's success and the extent and speed at which efficiency improvements are passed through in lower prices. If the grid remains publicly owned, it is crucial that the commercial activities of systems operation and market management be placed in a commercial organization—whether nonprofit or for-profit (and subject to careful oversight).

One of the most persuasive arguments for delaying the privatization of a national grid is that it is hard to value the assets, because in most cases transmission was bundled with generation. Many of the transactions between generators and the transmission operator would previously have been internal transactions and canceled out. But under privatization they become revenues for the transmission operation and costs for the generation companies. There will be no history of accounts, let alone regulatory accounts, for the grid under its previous integrated form, so any revenue projections will have to be taken largely on trust. These projections will be strongly influenced by how regulation operates and the extent of cost reduction. The same is true for the distribution companies, but most will have been separate companies

before and so have accounts setting out their costs. Thus there is less uncertainty in their case.

The absence of reliable accounts for the stand-alone grid business is a major problem—one that the passing of time will hopefully resolve. Another important issue under privatization is determining local transmission charges. Experiences from several countries indicate that it takes time to develop satisfactory regulated charges and incentives, and these may affect the reliability of revenue and cost forecasts. There is no obvious danger in delaying the privatization of transmission for several years after the privatization of distribution and generation, and there may be advantages.

Regulatory Challenges

GENERATION AND SUPPLY (RETAILING) ARE COMPETITIVE or contestable activities, and the normal policy conclusion would be that those activities should be deregulated. But given electricity's unique economic and technical characteristics (low elasticity of demand, nonstorability, significant short-run capacity constraints), electricity markets are highly vulnerable to the exercise of market power. Thus prices in wholesale electricity markets can remain well above competitive levels even when concentration is not especially high in the generating segment of the market (Newbery 2003). A policy of deregulation that does not explicitly address market power could seriously undermine the potential benefits of restructuring (Borenstein, Bushnell, and Wolak 2000). Moreover, distribution and transmission are prone to market failures (mainly due to their natural monopoly characteristics) and so also require regulatory oversight.

Regulation of Distribution

Restructuring and privatization are not feasible without a commitment to cost-reflective tariffs. The first step is to identify the efficient costs of distribution. These will include interest on and depreciation of the asset value (or regulatory asset base; Newbery 1997), as well as the efficient level of operating costs and distribution losses. The efficient operating costs may be substantially lower than what can realistically be achieved

in the near term, raising questions about how best to motivate improvements without greatly increasing the risk placed on the company.

One appealing but risky strategy is to specify in detail how tariffs will be set over a realistic time horizon (four or five years) and how they will be revised periodically thereafter, then invite bids for the right to these revenue streams. This approach avoids one problem—that of determining the speed at which the company is able to drive costs down to the efficient level—but creates several others: the problem of determining the initial asset value, the bigger problem of how to reset the tariff, and the related risks of receiving a low privatization sales price or granting an unacceptably high return to buyers (or both).

All these problems will be better illuminated as experience accumulates. Chile has been commended and criticized for basing distribution tariffs on a hypothetical distribution company. One advantage of this approach is that it allows a determination of the total unit cost (including the return on capital) and provides strong incentives to outperform. But it suffers from high realized rates of return (the recent criticism) or from excessive risk or inadequate returns to investment (and to avoid this, tariffs may have to be set so high as to risk the first objection).

There is relatively little experience with resetting tariffs (apart from the unsatisfactory annual revisions in Orissa, India), so it remains to be seen whether experiences from advanced industrial countries (such as the United Kingdom) will translate to developing countries (or to which ones). Several issues have to be addressed in resetting tariffs—most obviously inflation but also sensitivity to various cost drivers.

Reviewing the tariff structure and setting the final price. The distribution company will need to decide how to set various tariffs—distribution use of system (DUOS) charges—for its various customer classes (high-, medium-, and low-voltage). If the company operates under a revenue control formula designed to cover total costs, it will have an incentive to make these tariffs cost-reflective. That is because if one tariff is set above cost, some other tariff will be below cost, and an increase in sales under the latter tariff will generate losses.

Once the wholesale (or ex-power station) price is determined, the main elements are in place to determine the final prices of electricity delivered to franchise customers. This will be the wholesale price plus

the transmission use of system (TUOS) and DUOS charges, and the amount needed to cover the costs of supply (billing, meter reading, contracting, and so on). The main mistake to avoid is regulating prices that contain volatile elements without some means of passing through or insuring against fluctuations in uncontrollable components, the most important of which is the wholesale price. If the final price is capped and the wholesale price is free to increase sharply, and if suppliers are not hedged with contracts, they will quickly go bankrupt, as in California.

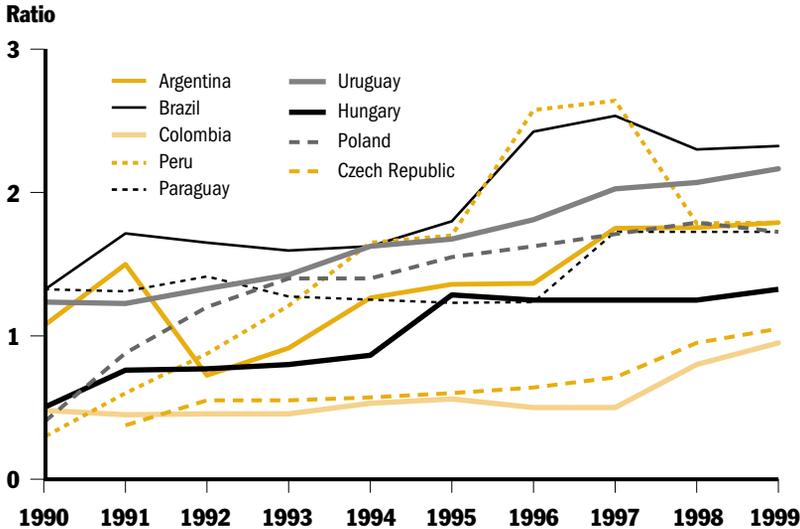
As long as distribution companies are not prevented from rebalancing their tariffs and supply companies can pass through all the costs in the chain (wholesale electricity price, TUOS, ancillary services, DUOS) with an adequate margin, distribution companies can be privatized without waiting for a full restructuring of generation. The converse, of privatizing generation before implementing the full mechanism for sustainable pricing of the downstream elements, is unwise and may be very costly.

Rebalancing tariffs. Like industrial countries, developing and transition economies face political opposition to higher electricity prices and have found it difficult even to raise prices in line with inflation. Prices can be kept down by ignoring the capital embodied in transmission and distribution networks and by covering the average—rather than the marginal—cost of generation, again ignoring most of the capital value of the equipment.

The margin between wholesale and retail prices can be squeezed in the medium run by writing down the asset value and hence the regulatory asset base. But over time, as new investment is added, the capital cost element in transmission and distribution prices will gradually rise. This gradual adjustment will be less painful politically than a sudden increase, but at the cost of reduced proceeds from the sale of the transmission and distribution companies.

Better strategies are available to ease the transition to cost-reflective prices. Many countries offer lifeline rates, where customers pay a subsidized rate for a minimum level used each month (such as the first 50 kilowatts) and the marginal efficient rate for consumption beyond that. This approach selectively transfers to households the rents associated with past investment in the network while encouraging efficient con-

Figure 3.6 Average Ratios of Household to Industrial Electricity Prices, 1990–99



Source: Jamasb (2002).

sumption. Yet in some countries commercial, regulatory, and eventually political pressures conspire to eliminate lifeline pricing (Hungary is the most recent example, in 1999).

There seems to be no reason to subsidize industrial customers, who together usually account for about two-thirds of electricity demand. In some countries agricultural users pose a politically intractable problem—as in India, where underpricing creates serious inefficiencies, leading to the use of socially more expensive electric pumps for tube-wells in place of perfectly adequate diesel pumps.

Historically, electricity prices in developing and transition economies included significant cross-subsidies from industrial customers to households. Open entry makes such subsidies unsustainable. Indeed, as these countries have begun to liberalize their electricity markets, cross-subsidies have been reduced and in some cases eliminated (figure 3.6).

Moreover, electricity underpricing cannot be defended on income distribution grounds. The main beneficiaries are invariably richer urban dwellers, and the costs are felt indirectly by poor people, who may be deprived of the chance to get electricity at all because of the country's inability to finance the extension of the system. Electric light is much

cheaper than kerosene and other alternatives, and customers are willing to pay high prices for a minimum level of consumption that provides light and allows the use of a television and small appliances. Political support may be concentrated in urban areas, where consumption is highest. But even there, improvements in quality (avoiding blackouts and brownouts) may more than compensate for higher prices.

Problems of Market Power

Most of the attention of the standard electricity reform model (entailing the separation of transmission, distribution, and system control from competitive generation and wholesale and retail marketing) has focused on issues of vertical market power. Thus considerable effort has been devoted to designing rules that ensure nondiscriminatory access to the transmission network by potential entrants in generation.

But one of the most important second generation issues in restructured electricity markets is the potential exercise of horizontal market power. Even in some large industrial countries that had an opportunity to create several private generators of approximately equal size, the market structure of generation tends to be highly concentrated. Market concentration in generation is even more pronounced in developing and transition economies (table 3.4).

Electricity markets are especially vulnerable to the exercise of market power because they are characterized by highly inelastic demand, significant short-run capacity constraints, and extremely high storage costs. These factors make traditional measures of market concentration somewhat inaccurate indicators of the potential for—or existence of—market power (Borenstein, Bushnell, and Wolak 2000). Moreover, an electricity market may sometimes involve very little market power, and other times suffer from a great deal. The shift between these states occurs when demand rises above the level that generators can supply. In addition, the distinction between these states is more pronounced in markets where small generators have limited production capacity and there is widespread potential for transmission congestion (Borenstein, Bushnell, and Knittel 1999).

These factors make the elasticity of demand for electricity a crucial factor in determining the potential effects of market power. Concentration measures do not incorporate information about the elasticity of

Table 3.4 Market Shares of the Three Largest Generation, Transmission, and Distribution Companies in Various Countries, 2000*(percent)*

Country	Generation	Transmission	Distribution
Argentina	30	80	50
Bolivia	70	100	70
Brazil	40	60	40
Chile	67	100	50
Colombia	50	100	60
Czech Republic	71	100	49
El Salvador	83	100	88
Hungary	74	100	65
Indonesia	100	100	100
Malaysia	62	100	97
Pakistan	95	100	100
Panama	82	100	100
Peru	100	100	100
Poland	45	100	21
Thailand	100	100	100

Source: Jamasb (2002).

demand and so might be inaccurate indicators of market power. Indeed, electricity markets that are not overly concentrated could still be vulnerable to the exercise of market power. The dictum of confining regulation to the natural monopoly segments of the electricity industry has often been taken too literally—paying too little attention to the unnatural, or at least undesirable, monopolies in generation.

Thus there is a need for regulatory oversight to ensure that wholesale markets are not manipulated. A number of market power mitigation strategies are available to policymakers. Deciding on a suitable one requires careful analysis of where a country's market power problems are likely to occur. Strategies could include:

- Horizontal deconcentration of generation resources.
- Fixed-price supply contracts that encourage generators to expand rather than withhold supply.
- Investments in transmission capacity, to reduce the ability of large players to strategically congest transmission lines.
- Measures that promote long-term contracts (for example, requiring generators to offer a portion of their expected annual sales in the form of long-term forward contracts).

- Measures that make electricity producers and customers more responsive to short-run price fluctuations (Joskow 2000a; Wolak 2001).

Where wholesale markets have worked well in industrial countries, it has largely been because of excess generation capacity, modest demand growth, and the availability of cheap new technologies that allow independent power producers to enter at modest scale, putting downward pressure on prices. California has shown that tight demand, low contract coverage, and a liberalized wholesale market can quickly lead to high prices and bankruptcy (box 3.6). That raises the obvious question of whether competitive markets can work well in developing and transition economies with limited capacity, excess demand, and rapid projected growth in demand. The answer will depend on the existence of credit-

Box 3.6 Lessons from California's Experience

WHAT LESSONS DOES CALIFORNIA'S RECENT EXPERIENCE offer for electricity reform? First, tight electricity markets—those where the reserve margin falls below 10 percent—are likely to lead to high and volatile prices even if they are fairly competitive (meaning there are four or more generators competing at the margin of supply). As demand tightens relative to supply, inelastic and unresponsive demand means that large price rises have little effect on demand—but each supplier has growing and eventually considerable market power. The large price increase caused by any company withdrawing a small amount of capacity is more than sufficient to compensate for the loss of profit on that volume of sales, making such withdrawals highly profitable in tight markets.

Second, any transition from a vertically integrated utility to an unbundled structure introduces price risks between generators and suppliers that previously cancelled out. High wholesale prices for generators create profits that are matched by the losses of suppliers who must buy at those prices and sell at pre-

determined retail prices (unless purchases are hedged by contracts). Thus the transition to an unbundled industry requires contracts and hedging instruments to insure against unexpected events that can have dramatic effects on spot prices, particularly when suppliers sell at fixed prices. To reduce transitional risks, the U.K. privatization was accompanied by three-year contracts for sales of electricity and purchases of fuel.

Third, in an interconnected system operating under a variety of regulatory and operational jurisdictions, spare capacity is a public good that may not be adequately supplied unless care is taken to ensure that it is adequately remunerated. Fourth, it is even harder for a decentralized market under multiple jurisdictions to ensure adequate reserve capacity with a potentially energy-constrained hydroelectric system, particularly where reservoir storage is limited and annual water volume variations are high. Finally, uncoordinated and injudicious regulatory interventions in such an interconnected system can have perverse local effects and damaging impacts on interregional electricity trade

Source: Wolak, Nordhaus, and Shapiro (2000); Wolak and Nordhaus (2001).

worthy electricity buyers (ideally suppliers) willing to enter long-term contracts that can then finance new investment in generation. Such investment requires satisfactory pricing of transmission and distribution to ensure that power can be delivered from generators to customers.

If capacity is scarce, spot prices can rise to high levels in a competitive market. Provided that franchise customers are adequately covered by contracts—which can be imposed on state-owned generators when they are unbundled—high spot prices signal that entry is attractive and encourage customers to sign contracts that finance entry. High spot prices also ration scarce supply to customers most willing to pay them, and motivate such customers to seek more attractive long-term arrangements. Thus high spot prices provide finance at the margin, where it is needed, without necessarily raising prices for all customers. Markets, contracts, and well-regulated transmission and distribution charges therefore represent a significant improvement over a situation of power interruptions, underpriced electricity, and an inability to finance needed generation.

Nevertheless, although contracts may restrain market power in the short term, it will reappear when contracts are due for renegotiation—assuming that generators are privately owned and cannot be coerced to sign new contracts. Market power depends on the number of competing generators and overall market demand relative to capacity. If demand is inelastic and generators cannot meet it, those generators will have considerable market power. In a competitive wholesale market every generator will be aware of that power and will offer at least marginal output at a high price. Investment will reduce this market power only if there are enough independent generators.¹²

Relying on contracts alone may not be sufficient to address issues of market power, and it is important that a regulator has sufficient authority to implement a variety of market power mitigation mechanisms. In particular, the regulator should be given the authority to collect cost data and technical information from all generators.

Incentive Regulation for Transmission

One of the biggest policy challenges for a restructured electricity industry is developing regulations that encourage transmission owners and operators to operate efficiently and invest in increased capacity.¹³

The success of electricity restructuring, its reliance on competitive generation, and its ability to benefit customers depend on a robust transmission network—indeed, one more robust than during the era of vertically integrated monopolies.

Transmission regulation historically paid too much attention to transmission's direct costs (capital and operating costs) and too little to its indirect costs (congestion, ancillary services, local market power mitigation costs). The direct costs of transmission are a small fraction of the total costs of electricity supply: usually less than 10 percent of the average customer's bill. Any great effort to fine-tune the allowed return on transmission investments is unlikely to be greatly appreciated by customers. More important, regulators will not be doing customers any favor if a small price reduction in the short run destroys a transmission owner's incentives to invest. That is because in the long run, inadequate transmission investment increases congestion costs, market power problems, ancillary service costs, and the frequency and magnitude of energy price spikes.

The indirect costs of transmission include thermal losses, some of the costs of ancillary services, excessive costs and delays in connecting new generators, and the costs of local market power, market power mitigation mechanisms, and out-of-merit dispatch of generating plants to manage congestion and maintain network frequency, stability, and voltage criteria. The magnitude of these indirect costs depends on the incentives that transmission owners and operators have to minimize them through the choices they make about network operations and maintenance as well as when, how, and where they invest in network expansion.

Regulation for competitive wholesale electricity markets should encourage the efficient operation and expansion of the transmission networks on which these markets depend. In addition to providing financial incentives to transmission owners, regulation should lead them to view the pursuit of public interest goals as a business opportunity—not as a burden forced on them. The U.K. electricity sector has nearly a decade of experience with incentive-based mechanisms governing the revenues of the National Grid Company. Of particular interest is the transmission services scheme, which provides financial incentives for the company to reduce transmission uplift costs (the costs associated with thermal losses, ancillary services, and out-of-merit dispatch to manage congestion). The scheme does this by setting an uplift cost tar-

get, rewarding the company if it achieves the target, and penalizing the company if it exceeds it. This regulatory scheme combines a conventional price cap mechanism (covering the bulk of direct transmission system charges) with incentive schemes (applicable to transmission uplift costs and reactive power costs) and a separate mechanism governing cost recovery for connecting new generators to the system. Together these mechanisms have encouraged substantial new investment in the network, facilitated generator interconnections, reduced transmission uplift costs, and increased network reliability.

Reform Experiences and Lessons

IN MOST COUNTRIES ELECTRICITY REFORM IS STILL TOO RECENT to assess its effects on social welfare. Only a few countries have time-series data of sufficient length to permit meaningful empirical assessments. Still, several lessons can be gleaned from the experiences of countries that have the longest experience and that have gone the farthest with reforms.

Progress on Reform and Private Participation

Fiscal pressures, exacerbated by poor sector performance, have been the main drivers of electricity reform. Although these programs have generally sought increased private participation, reform strategies and success in attracting private investment have varied considerably across countries and regions. And while electricity restructuring is spreading, many countries have taken few or no steps toward reform.

By 1998, 15 countries had substantially liberalized their electricity systems, and 55 had some liberalization under way or planned—but many of these reformers were mature industrial countries. Of the 81 countries that had not taken any steps toward reform, many were developing and transition economies (Bacon and Besant-Jones 2001). Even in Latin America, the leading region for private participation in electricity, reforms are far from complete. In 2001 the state still controlled significant portions of electricity activities in many Latin American countries (Millan, Lora, and Micco 2001).

Table 3.5 Electricity Reforms by Region, 1998*(percentage of countries where reform has occurred)*

Reform	East Asia and Pacific	Europe and Central Asia	Latin America and Caribbean	Middle East and North Africa	South Asia	Sub-Saharan Africa
State utility corporatized	44	63	61	25	40	31
Enabling legislation passed	33	41	78	13	40	15
Independent regulator at work	11	41	83	0	40	8
Private investment	78	33	83	13	100	19
State utility restructured	44	52	72	38	40	8
Generation privatized	22	37	39	13	40	4
Distribution privatized	11	30	44	13	20	4
All reforms taken	41	45	71	17	50	15
Reform score (scale of 1–6)	2.44	2.70	4.28	1.00	3.00	0.88

Source: Bacon and Besant-Jones (2001).

Table 3.5 presents a regional scorecard for electricity reform as of 1998, based on how many of the following steps had been taken by each country in a region:

- The state-owned electric utility has been commercialized and corporatized.
- Parliament has passed an energy law permitting partial or complete sector unbundling or privatization.
- A regulatory body, separate from the utility and the ministry, has started work.
- The private sector has invested in greenfield sites that are being built or operating.
- The state utility has been restructured or unbundled.
- The state utility has been privatized, whether through outright sale, voucher privatization, or a joint venture.

Out of a maximum reform score of 6.00 (where all reform steps were taken), the average score was 4.28 for Latin America and the Caribbean, 3.00 for South Asia, 2.70 for Central and Eastern Europe and Central Asia, 2.44 for East Asia and the Pacific, 1.00 for the Middle East and North Africa, and 0.88 for Sub-Saharan Africa.¹⁴

The level of private sector interest has been extremely mixed across countries and regions, reflecting differences in reform efforts. Between

Table 3.6 Private Investment in Electricity by Region, 1990–99*(billions of 2001 U.S. dollars)*

Region	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Total
East Asia and Pacific	0.1	0.5	5	6.2	7.8	7.9	12	15.1	5.6	1.6	3.9	2.9	68.6
Europe and Central Asia	0.1	—	1.1	—	1.4	3.7	3.5	2.3	0.6	0.7	4.6	1.1	19.1
Latin America and Caribbean	0.9	—	2.7	3.6	3.1	6.3	9.8	23.2	14.9	8.1	13.1	3.8	89.5
Middle East and North Africa	—	—	—	—	0.2	—	0.2	1.7	—	1	0.2	0.8	4.1
South Asia	0.2	0.8	0	1.3	2.5	3	4.6	1.7	1.6	2.5	3	0.9	22.1
Sub-Saharan Africa	0.1	—	—	—	0.1	0	0.5	0.5	0.8	0.5	0	0.7	3.2
Total	1.4	1.3	8.8	11.1	15.1	20.9	30.6	44.5	23.5	14.4	24.8	10.2	206.6

Source: World Bank, Private Participation in Infrastructure Project database.

1990 and 2001 developing and transition economies received approximately \$207 billion in private investment in power projects (table 3.6). Over 43 percent went to Latin America and the Caribbean and about 33 percent to East Asia and the Pacific—while 2 percent went to the Middle East and North Africa and approximately 1.5 percent to Sub-Saharan Africa.

Private sector participation also varied considerably over the 1990s. Until 1997 electricity reforms and anticipated economic growth spurred enormous private investment in the sector. But investment then plummeted, reflecting financial problems in many countries in Asia, Eastern Europe, and Latin America (see table 3.6). It is difficult to predict whether this reversal will persist (Jamásb 2002).

Reform strategies have also differed significantly across countries and regions. Several Latin American countries (Argentina, Bolivia, Brazil, Chile, Colombia, Peru) restructured and unbundled their electricity systems and created wholesale electricity markets. This approach is also being adopted in Eastern Europe (Bulgaria, Hungary, Romania) and the former Soviet Union (Armenia, Estonia, Georgia, Latvia, Moldova). Other approaches involve:

- Limiting reform to the creation of independent power producers (Croatia, Slovak Republic).
- Providing third party access to a dominant utility (Czech Republic).

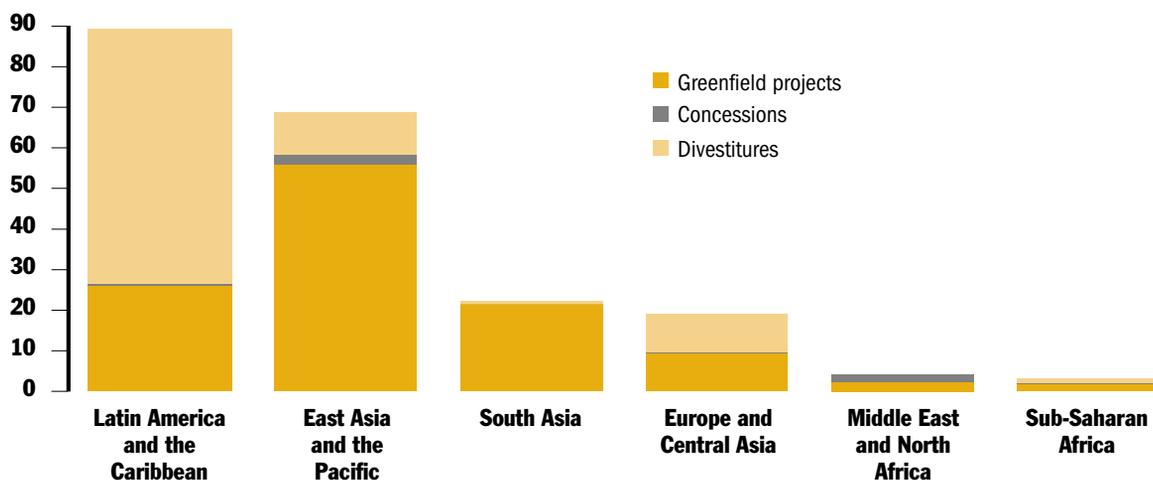
- Restructuring with plans for major divestitures (Poland, Russian Federation, Ukraine).

Many Asian countries have adopted variants of the single buyer model and invited private investment in generation through independent power producers, with negligible restructuring and reform (Bangladesh, China, India, Indonesia, Malaysia, Nepal, Pakistan, Philippines, Republic of Korea, Sri Lanka, Thailand, Vietnam). The model of independent power producers selling electricity to state-owned utilities has been adopted by countries in Central America and the Caribbean (Belize, Costa Rica, the Dominican Republic, Guatemala, Honduras, Jamaica, Mexico, Nicaragua, Panama); the Middle East and Africa (Algeria, Côte d'Ivoire, Egypt, Ghana, Jordan, Kenya, Morocco, Senegal, Tanzania); and South Asia. Almost 70 percent of private investment in electricity in Latin America and the Caribbean has been in divestiture projects, while more than 83 percent in East Asia and the Pacific and South Asia has been in greenfield projects (figure 3.7).

During the 1990s, 12 countries accounted for 83 percent of the private electricity investment in developing and transition economies (figure 3.8).¹⁵ Some countries, such as Argentina and El Salvador, have attracted investment to all parts of the electricity industry. But

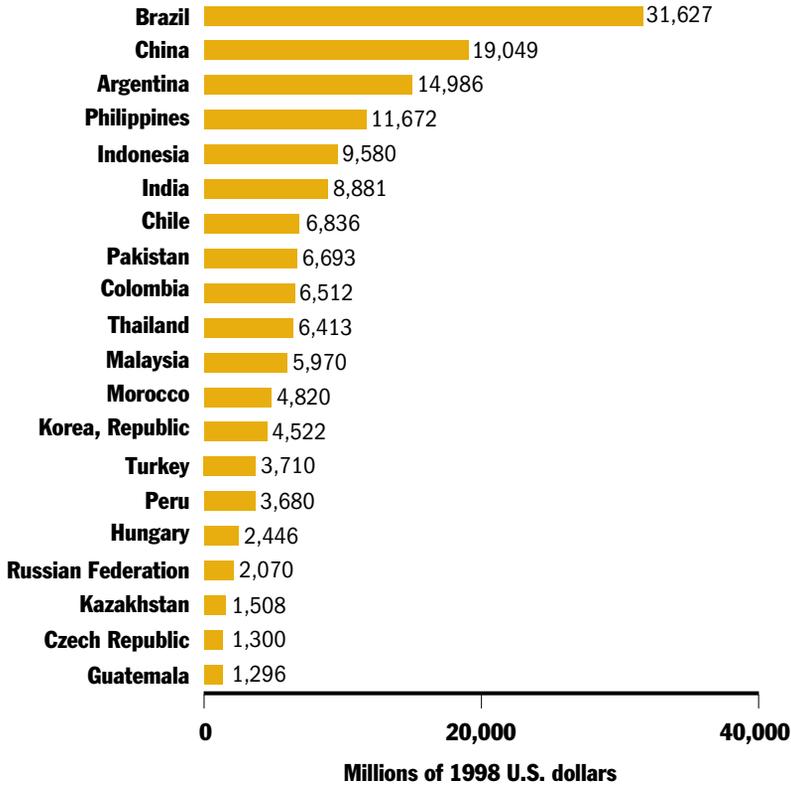
Figure 3.7 Types of Private Investment in Electricity, by Region, 1990–2001

Billions of 2001 U.S. dollars



Source: World Bank, Private Participation in Infrastructure Project database.

Figure 3.8 Top 20 Recipients of Private Investment in Electricity, 1990–99



Source: Jamasb (2002).

private investors have shown little interest in purchasing state enterprises or financing new infrastructure assets in Mexico, Turkey, and Ukraine, to name just a few examples. Indeed, some countries—including Hungary and Venezuela—have had to postpone privatization for lack of investor interest. Despite government efforts to attract private capital, these countries have been unable to reverse long periods of underfunding.

Reform Outcomes

Sector performance has improved dramatically in countries that have implemented electricity reforms such as competitive (vertical and hor-

izontal) restructuring, privatization, credible regulation that fosters efficient behavior by market participants, well-designed wholesale markets with enough independent suppliers to facilitate competition, and retail competition, at least for industrial customers (Joskow 2003a).

Achievements of privatization and liberalization in Latin America.

Latin America is not only where the first electricity reforms started—in Chile—but also where the standard reform model has been most influential and far-reaching (Suding 1996; Millan, Lora, and Micco 2001). Reforms in Chile (1982) were followed by reforms in Argentina (1992), Peru (1993), Bolivia and Colombia (1994), Costa Rica, El Salvador, Guatemala, Honduras, Nicaragua, and Panama (1997), and more recently Brazil, Ecuador, Mexico, and Venezuela (Rudnick and Zolezzi 2001). How well have these efforts worked?

The sequencing of Chile's reforms is instructive. The first steps involved creating regulation and restructuring the sector, to give reorganized enterprises experience with the regulation before privatization. To allay investors' fears about expropriation, the reform program paid special attention to clearly defining property rights in primary legislation that would be difficult to change. Privatization proceeded slowly, avoiding some of the risks of underpricing or large transfers to shareholders, while wide share ownership created political support for the new system (Bitran and Serra 1998; Newbery 2001). Progress under Chile's cautious approach showed the feasibility of private involvement in electricity in developing countries and provided valuable lessons for subsequent reforms around the world.

Chile's restructuring sought to achieve vertical and horizontal unbundling, competition in generation, a centralized power pool, open access to the transmission network, yardstick competition in distribution, and for large users freedom to purchase power from any generator or distributor. In 1986 Endesa, the state-owned vertically integrated electric utility, was split into six generating companies, six distribution companies, and two small isolated companies in southern Chile providing generation and distribution (Fischer, Gutierrez, and Serra 2003). Chilectra, which was nationalized in 1970 and controlled distribution in Santiago, was split into three companies: a generation entity and two distribution companies.

By 1991 Chile had 11 generation companies, 21 distribution companies, and 2 integrated companies. But these numbers are misleading in terms of the actual competition that emerged in generation. In 2000, 93 percent of installed generation capacity and 90 percent of generation were controlled by three companies: Endesa, Gener, and Colbun. The largest of these, Endesa, controls 58 percent of generation in Chile's large central region, which accounts for most of the country's electricity demand, and the company has most of the national water rights. Endesa also owns the country's largest distribution company, which provides more than 40 percent of distribution (Arellano 2003). And until 2000, when it was forced to divest, Endesa owned and operated the country's main high-voltage transmission grid.

Thus Chile's post-reform electricity market was not particularly competitive. Market power remains significant in generation. Moreover, Endesa's ownership of the largest distribution company (and until recently the main transmission company) gave it a competitive advantage over third party generators. It could handicap potential competitors through its control of bottleneck transmission facilities, self-dealing, and cross-subsidies. However, the ability of generators to exploit their market power was somewhat constrained by the adoption of a cost-based spot market.

Other reformers learned from Chile's mistakes, and most—such as Argentina, Bolivia, and Peru—restricted cross-ownership. They also sought to reduce horizontal market power, with Argentina limiting ownership of generation assets to 10 percent of the market and Bolivia limiting it to 30 percent. Argentina also developed one of the world's most competitive wholesale electricity sectors. By 1993 it had 70 firms trading in the bulk supply market. And by 1997 it had 40 generation and more than 20 distribution companies (Rudnick 1998).

Overall, privatization and the application of high-powered regulatory mechanisms have led to dramatic efficiency improvements in the electricity industry. In Chile labor productivity in Endesa's generation business increased from 6.3 gigawatt-hours generated per employee in 1991 to 34.3 in 2002. Similarly, labor productivity in Chilectra's distribution business improved from 1.4 gigawatt-hour sales per worker in 1987 to 13.8 in 2002 (Fischer, Gutierrez, and Serra 2003; Pollitt 2003).¹⁶ In Argentina thermal plant unavailability fell from 52 percent in 1992—when most generation capacity was privatized—to 26 percent in 2000 (Rudnick and Zolezzi 2001). The improvements in Chile

Figure 3.9 Post-Privatization Labor Productivity in Electricity Distribution in Argentina, Chile, and the United Kingdom



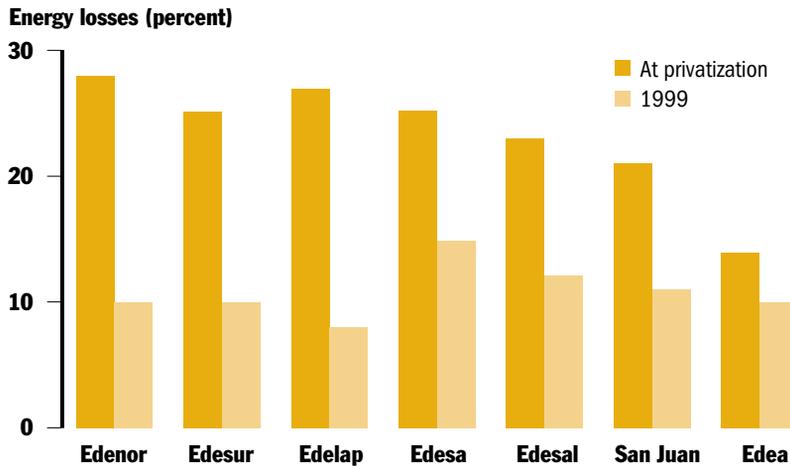
Note: Measured in terms of gigawatt-hours of sales per employee.

Source: Pollitt (2003).

and Argentina are impressive even relative to the performance of privatized U.K. electricity companies (figure 3.9). Brazil's distribution and supply companies also saw labor productivity accelerate after privatization: between 1994 and 2000 the number of employees was halved and productivity jumped 147 percent (Mota 2003).

Reforms have had equally remarkable effects on the quality of supply. In Chile the average time for emergency repair service declined from 5 hours in 1988 to 2 hours in 1994. In addition, power outages due to transmission failures have fallen steadily since privatization (Rudnick and Zolezzi 2001). Energy losses, including theft, have also shrunk, dropping from 21 percent in 1986 to 9 percent in 1996 (Fischer and Serra 2000). Similarly, Argentina's privatized distribution companies have substantially cut their losses (figure 3.10). For example, in 1993 Edenor's losses equaled 26 percent of its distributed electricity; in 2000 its losses were just 10 percent (Edenor 2001). In the greater Buenos Aires area the number of hours of supply lost per year dropped

Figure 3.10 Energy Losses among Argentina's Distribution Companies, at Privatization and in 1999

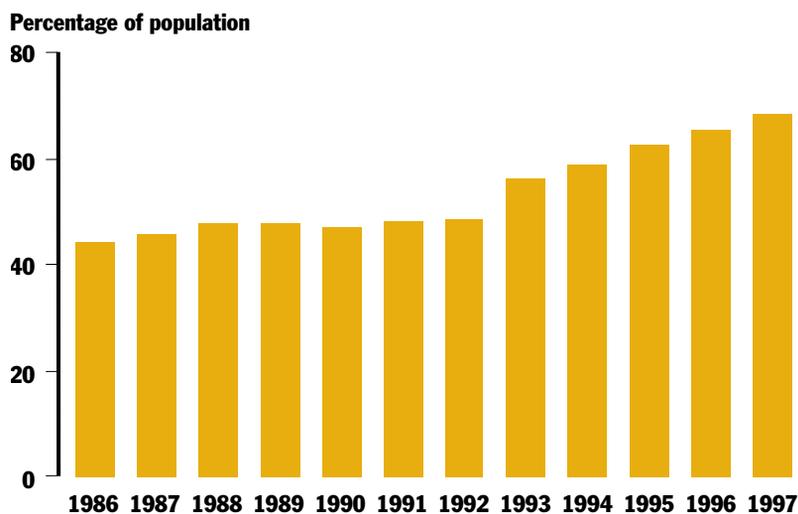


Source: Feler (2001).

from 16.8 in 1994 to 5.0 in 2001 (CAISE 2002). Technical losses in transmission also fell, from 6 percent in 1992 to 4 percent in 2000.

By relaxing the financial constraints facing state enterprises and establishing stable and fair regulation, electricity reforms have promoted investment and accelerated network expansion. In Argentina installed capacity grew from 13,267 megawatts in 1992 to 22,831 megawatts in 2002—an increase of nearly 5 percent a year. During the same period the route length of transmission lines rose from 16,958 to 22,140 kilometers (2.7 percent a year). Similarly, in Chile's main system installed capacity jumped from 2,713 megawatts in 1982 to 6,737 megawatts in 2002 (4.4 percent a year), while the route length of transmission lines went from 4,310 to 8,555 kilometers during the same period (3.7 percent a year). The impressive expansion of generating capacity in Argentina and Chile was achieved by private operators while keeping prices low (Fischer, Gutierrez, and Serra 2003; Pollitt 2003).

Before reforms, service coverage in Peru increased slowly—from 44 percent in 1986 to just 48 percent in 1992 (figure 3.11). But in the five years after reforms were introduced, service expansion accelerated considerably, and by 1997 coverage was more than 68 percent (Rudnick 1998). Moreover, network expansion has benefited poor people: among the poorest 10 percent of Chilean households the share without an elec-

Figure 3.11 Electricity Coverage in Peru, 1986–97

Source: Rudnick (1998).

tricity connection fell from 29 percent in 1988 to 7 percent in 1998. Among the second poorest 10 percent the share without a connection fell from 20 percent to 4 percent (Estache, Foster, and Wodon, 2002). An innovative rural electrification program—which relied on private investment, decentralized decisionmaking, and competition for project financing and implementation—had similarly impressive results. Coverage in rural areas increased from 53 percent in 1992 to 76 percent in 1999, exceeding the original target of 75 percent set for 2000.

Electricity reforms have better aligned prices with underlying costs to reflect resource scarcity, as efficiency requires. In many countries this has meant increasing prices that previously were too low (Joskow 2003a). But in some countries prices have been falling due to the efficient exploitation of regional natural gas networks and new production technologies (mainly combined cycle gas turbines). In Argentina the average monthly price per megawatt-hour in the wholesale electricity market fell from about \$45 (with peaks of more than \$70) in 1992 to about \$15 in 2001. Similarly, in Chile the node price (including energy and capacity charges) of power delivered to Santiago fell from \$30.1 per megawatt-hour in October 1982 to \$23.3 per megawatt-hour in October 2002 (in October 2002 dollars), and for power delivered to Antofagasta fell from 102.4 per megawatt-hour in October 1984 to 24.8 per

megawatt-hour in October 2002 (Fischer, Gutierrez, and Serra 2003; Pollitt 2003). Between 1986 and 1996 wholesale prices dropped 37 percent and final prices fell 17 percent.

The low prices of electricity and high rates of investment in Chile and Argentina have been accompanied by strong financial performance among the companies involved. In Chile, Chilectra's average nominal rate of return on equity during 1996–98 was 32 percent. Endesa's return on equity peaked at 16 percent in 1994 (Fischer, Gutierrez, and Serra 2003). In Argentina the financial performance of the largest state-owned company, Servicios Electricos del Gran Buenos Aires, was very poor before privatization. After, the average rate of return on equity in generation was 5.6 percent during 1994–99. The transmission company, Transener, earned a 5.1 percent rate of return on equity in 1998. Among distribution companies, during 1994–2000 Edenor and Edesur earned 8.3 percent and 7.2 percent pretax returns on net assets.

In Argentina, however, a severe macroeconomic crisis and a regulatory regime substantially weakened by political interference have undermined an otherwise spectacular sector transformation. In January 2002 the government scrapped an almost 11-year policy of pegging the peso one-to-one to the U.S. dollar. It also unilaterally modified the contracts under which it had privatized electric and other public utilities in the 1990s. For a year and a half after the devaluation, the regulated prices charged by public utilities remained essentially frozen (in pesos). Yet most of these contracts defined prices in dollars. Moreover, during the same period the cumulative inflation reached 45 percent at the retail level and 120 percent at the wholesale level (Urbiztondo 2003). As a result the revenues of the operating entities plummeted, while their debt and production costs (a significant portion of which were in dollars) soared. The generation, transmission, and distribution companies all posted big losses, and some saw their shareholders' equity get wiped out. Their condition was aggravated by delays in negotiations with the government. In May 2002 Transener suspended interest and principal payments on its \$420 million in debt (Platts 2002). In October 2003 the electricity companies issued a grave warning of a power crisis in Argentina (Casey 2003).

The East Asian crisis and deficiencies of the single buyer model.

The East Asian financial crisis called into question the strategy of pro-

moting rapid entry by private investors in an otherwise unchanged sector, with independent power producers selling to state utilities under long-term purchase agreements. Although this strategy seemed appropriate for East Asia given its power shortages in the late 1980s and early 1990s, the subsequent crisis highlighted the risks involved.

Several factors led to the region's power shortages, which were especially severe in Indonesia, Malaysia, the Philippines, and Thailand. These countries had experienced rapid economic growth, and so sharp increases in demand for electricity. But the public spending that fueled much of the growth left governments unable to finance expansions in electricity and other infrastructure. For example, during 1990–97 Thailand's electricity consumption rose 14 percent a year, but its installed capacity grew just 8 percent a year. In 1992 excess demand in the Philippines equaled 48 percent of system capacity, and in Malaysia the reserve margin fell to 19 percent, far below the 30–40 percent desired for rapidly industrializing economies. In 1990 it was estimated that Indonesia needed \$20 billion to install 12 gigawatts of additional capacity by 2000—and a revised forecast in 1993 called for an additional 12 gigawatts within five years. Similarly, analysis in 1993 concluded that more than \$40 billion was needed to meet Malaysia's peak demand, which was expected to skyrocket from 4.5 gigawatts in 1992 to 35.4 gigawatts in 2020 (Henisz and Zelner 2001).

Seeking relief from these supply shortages, these and other East Asian countries encouraged the entry of independent power producers by offering them long-term purchase agreements with state-owned, single buyer utilities. The agreements typically involved payments in dollars and required government guarantees (because default proceedings against state utilities are usually not allowed). This strategy was successful. Between 1990 and 1997 East Asia attracted \$54.6 billion in private investment in electricity—more than 40 percent of the total for developing and transition economies. The other major recipient, Latin America, received \$49.6 during this period (see table 3.6).

The financial crisis that started in East Asia in 1997 caused dramatic damage to the region's exchange rates, GDP growth rates, and electricity demand. The collapse in currencies doubled the cost of electricity under power purchase agreements—an increase that state-owned power companies were reluctant to pass on to customers. In the Philippines the foreign debt of the national power corporation rose to more than 20 percent of national debt (World Bank 1999a). Lower demand for electric-

ity created strong pressures to renege on, delay, or renegotiate power purchase agreements, causing foreign investors to lose confidence.

It became painfully clear that this form of private investment in power generation is equivalent to expensive foreign debt. The terms of a power purchase agreement may conceal the true cost of the debt, but interest rates are inevitably high because of the source of finance and the risk involved. Even in stable markets private investors borrow at higher interest rates than institutions like the World Bank, and in corrupt economies foreign investors consider lending to state enterprises especially risky. During the crisis some East Asian governments tried to repudiate debts incurred by previous administrations, often claiming that the deals were corrupt, while others had to reschedule loans to avoid default. In the end this type of private involvement did not lead to much sector restructuring or address the problem of non-cost-reflective tariffs. If anything, the currency crisis worsened the problem of inadequate tariffs (Newbery 2001).

Lessons

During the 1990s many industrial, developing, and transition economies implemented significant institutional reforms in their electricity sectors. Although many of these efforts are still under way, experiences to date offer important insights on the reform process:

- When properly designed and implemented, a combination of institutional reforms—vertical and horizontal restructuring, privatization, and effective regulation—can significantly improve operating performance. In reformed electricity systems, labor productivity has increased in generation and distribution, in some countries dramatically. In addition, technical and nontechnical losses have been reduced and service quality has improved.
- Most reforms have attracted considerable private investment—one of the main goals of restructuring—in generation and distribution (though less in transmission). Thus a long history of underinvestment is being reversed in reforming countries.
- In several countries (such as in Latin America) electricity prices have fallen as wholesale markets have developed and entry by new generators has expanded supplies and increased competition.

- Retail prices have become more closely aligned with underlying costs, and cross-subsidies have been reduced and in some countries eliminated (Joskow 2003a).
- Substantial risks are created for the public interest when governments promote rapid investment in an unreformed electricity sector by offering independent power producers long-term power purchase agreements with state-owned, single buyer utilities.
- Many if not most developing and transition economies lack some of the initial conditions required to implement competitive wholesale markets, including a large number of independent generating companies, active participation by final consumers in the wholesale market, adequate transmission capacity, and a credible regulatory mechanism. Thus the introduction of unregulated bid-based spot markets could lead to significant problems in these countries. A less risky strategy might be to rely on marginal cost bidding systems.

Notes

1. This chapter draws heavily on Newbery (2001).
2. It is widely accepted that there must be a single network operator responsible for overseeing the operations of a control area—coordinating generator schedules, balancing loads in real time, acquiring ancillary support services to ensure network reliability, and coordinating with neighboring control areas (Joskow 2000a). Thus the system control function has attributes of a natural monopoly.
3. An important distinction between developing and transition economies is that the latter have achieved much higher service coverage in the electricity sector.
4. These are plants that use once-through boilers with operating pressures above 22.1 megapascals—the critical pressure point for water and steam.
5. When assets of a regulated utility are not used due to changes in economic conditions (such as the introduction of competition) or technology, they are considered stranded. Similarly, stranded costs are prudent costs incurred by a utility that may not be recoverable under competition or deregulation.
6. Simple-cycle combustion turbines are now being built with heat rates of 10,000 BTUs per kilowatt-hour, and this will fall to perhaps 9,500 BTUs in

the next cycle of technologies. This is as efficient as steam-turbine plants built in the 1970s, and far more efficient than combustion turbines built then.

7. Distributed generation is the integrated or stand-alone use of small, modular electric generation facilities close to the point of consumption. It encompasses many technologies that vary by size, application, and efficiency (see figure 3.3). Several important regulatory issues are associated with distributed generation. First, for distributed generation connected to the power grid (most customers will want to retain such a connection to guard against emergencies), interconnection terms and conditions will require regulatory oversight. Distribution utilities will demand a high price for providing such backup access. In addition, if distributive generators are permitted to sell all or some of their power into the grid, there will be a need for regulatory protocols to support these transactions. Second, if cross-subsidies are embedded in user prices, there is a question of whether customers who bypass these regulatory burdens by leaving the system should be required to contribute to these costs. Otherwise the remaining captive customers of local distribution companies will be saddled with an even larger share of these regulatory burdens. Third, significant regulatory issues also arise when distributed generation is not connected to the grid—for example, in terms of activities that require regulatory oversight and those that should be fully deregulated.

8. This is not true for all small-scale technologies. Combined heat and power technologies achieve much higher efficiencies than do microturbines and are rapidly becoming economical—even at the level of individual households. In addition, fuel cell technologies have a good chance of achieving efficiencies in the mid- to upper 40s by 2010.

9. Retail competition may not involve all customers. It may be limited to industrial customers, with residential consumers served by distribution companies that buy in a competitive wholesale market, or (as in the United Kingdom) a transition over time of competition from the largest to smallest customers.

10. It is not only the transmission company that can exercise the role of single buyer. It can also be assumed by load-serving entities. For example, distribution companies could create an entity to buy power on their behalf. Variants of this model existed for many years in the United States in the form of “joint action agencies” for municipal distribution systems.

11. This is the case when the entity responsible for real-time dispatch is bundled with the active single buyer.

12. If generators have apparent market power, there will be a strong temptation to choose the single buyer model to countervail against it.

13. This section is based on Joskow (1999).

14. These types of evaluations of institutional arrangements can be misleading. For example, France would score low based on these criteria, but its electricity system performs very well. For a more accurate evaluation these reform scores should be augmented by data on physical and economic performance.

15. For more accurate regional comparisons, it would be necessary to distinguish between investments in new capital facilities and sales revenue from the divestiture of existing capital facilities.

16. The improvements in labor productivity accelerated after the takeover of the formerly domestically controlled companies by foreign companies. Between 1999 and 2002 the number of employees in Chile's electricity system fell from 8,264 to 5,706.