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At a Glance

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Options for Private Power

A framework for decisionmaking

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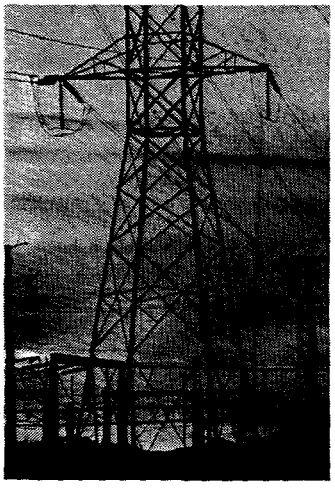

The shift to private power means countries have to choose from among several institutional models, ranging from the privately owned, vertically integrated utility to the fully "unbundled" or "pure" model in which power stations, transmission grids, and regional distribution networks are all privately and separately owned. There is often intense debate over which model to select and what criterion to use. There are some concerns that choices are too frequently driven by market ideology rather than objective analysis of the alternatives. To avoid or address these situations, standard indicators of economic performance, based on cost- and price-efficiency and quality of service, will provide some reliable and nonideological answers about what best suits a particular country—and will also indicate when and where reform is merited at all. This Note outlines the reform options, provides the standard indicators which may give some guidance on choice, and briefly reviews some of the risks policymakers face in any transition period.

Four Models

There are, broadly, four institutional models for a country to choose from. All contrast distinctly with the most

Impetus for change

There are several reasons why countries are seeking to move from state to private ownership:

- *The financial requirements of meeting new demands.* Demand is doubling every 7 to 10 years in most developing regions. Prices averaged less than half the supply costs in developing countries in 1991, owing to the political regulation of prices. Revenue shortfalls amounted to over $100 billion per year, and coincidentally were about the same as is required for new investments. Privatization is seen as a means of achieving price-efficiency where public ownership has failed.
- *Cost and managerial efficiency.* Large electrical losses, brown-outs, black-outs, and poor plant availability are common experiences with state-owned utilities, and have similarly caused many countries to look to private managers and private capital to improve the efficiency and reliability of supply.
- *Macroeconomics.* The drain on public revenues caused by subsidizing a state-owned utility has also led many countries to look for an alternative model.

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common *existing* approach based on state-owned and -controlled enterprises with no private share ownership—the point of departure for the majority of developing countries. The alternatives are:

Model I. The traditional model of the vertically integrated state-owned public utility, operated as a quasi-independent public corporation on commercial principles. Regulation is independent of—arm's length from—government, the utilities, and special interests. This is the model followed by most European utilities, including the U.K. until 1989, Korea, and Thailand. It is not, of course, strictly a private model, though what has differentiated it from the models followed by most developing countries is independent regulation and that it has attempted to "simulate" the results of market competition, e.g., through the adoption of commercial pricing policies (ideally marginal cost pricing).

Model II. Like *Model I,* but with financial resources being raised through private share ownership, bonds, and private borrowing, and with competition being introduced by private power producers (the U.S.).

Model III. Like *Model I,* with competitive procurement of new generation plus a contract or common carriage for transmission. Countries in the process of moving to complete vertical separation may pass through this phase (the U.S. since 1992, Mexico).

Model IV. Complete vertical separation of generation, transmission, and distribution, with full privatization of each (the U.K., Argentina, Chile, Peru).

Benefits of change

The choice of one model should not preclude evolution into another. A country can begin to reform its utility using *Model I* or *II,* and evolve to *Model III* or *IV.* None of the models can work without a reasonable degree of price-efficiency, or thus without solving the financial problem, and for this reason alone all have their merits. Moving from the state-owned enterprise to *Model I,* for instance, requires prices to reflect costs, and this would simultaneously (i) greatly improve internal cash generation in most countries and (ii) lay the basis for private capital to be raised in stock and bond markets, and through direct investment.

Model I would thus lead to financial self-sufficiency in the industry and eliminate the budgetary distresses that the poor pricing policies of the public utilities have caused in many countries. But it remains, nevertheless, a "regulated monopoly," and lacks the element of competition and the incentive for managerial and cost-efficiency in the provision of supplies. Second, regulated monopolies are often wedded to existing approaches and inhibit investment in newly emerging electricity supply technologies.

Model II overcomes these problems by admitting independent generation on the supply system. The model introduces competition in new generation, and attracts the additional financial and managerial resources associated with direct investment. In addition, it is associated with greater accountability because of the requirements of independent audits and the public scrutiny that comes with share ownership. The increased accountability extends not only to cost-efficiency in operations and investment, but also to public issues such as compliance with taxation and environmental laws and the provision of universal service.

Models III and IV are institutionally complex, and will not always be the most appropriate starting point for many countries. *Model III* opens plant dispatching schedules to competition and this is clearly a force for cost-efficiency. In addition, it should lead to improved tariff structures: prices would, in theory, be bid down to marginal fuel and operating costs at off-peak, and up to marginal capital plus fuel and operating costs at peak. Seasonal pricing would be encouraged on predominantly hydro systems, and contracts between supplier and consumer would lead to prices correctly reflecting costs according to voltage level. If prices did not reflect such cost levels and structures, this would be an unmistakable sign that competition was lacking.

Model IV has two advantages over *Model III*. First, it allows for the franchising of distribution services. Hence, companies that believe they could provide these services more efficiently are able to contest current arrangements. Second, distributors will be better placed than others in the industry to judge the commercial merits of decentralized electricity production, such as cogeneration or smaller-scale generation owned by the distribution company itself or by private investors. Modularity in fossil-fired plants and in renewable energy supplies is opening up many possibilities in this direction.

The biggest economic and financial gains might well be realized by going from the state-owned enterprise to *Model II*. Some countries might prefer this course if only because they could use the public utility to take the lead in extending regional and rural services. Another option might be to combine *Model II* with elements of *Model IV* (such as franchising) in order to encourage managerial and price-efficiency in supply and investment in decentralized generation.

Objective basis for choice

The success or failure of any institutional model can be objectively determined by measuring its economic efficiency. The advantage of the efficiency criterion is that it immediately suggests a range of indicators by which the success of a policy can be measured. Some indicators are shown in Table 1. They are neutral among institutional models, and are not influenced by ideological factors. If an electricity industry scores well on all of them, there might be no reason to reform it, no matter which model it conforms to—even if it is a public enterprise.

The indicators have been divided into three groups to reflect different aspects of economic efficiency: whether the investment and operating costs are being minimized by the new model (cost-efficiency); whether the level and structure of prices reflect the level and structure of costs (price-efficiency); and whether service is being provided in ways satisfactory to the public—a criterion which includes environmental factors as well as the provision of kWh. The table indicates where possible the standards that are typically achieved in best practice situations.

Managing risks in transition

Table 1 concentrates on "static" measures at a point in time only. But for most countries the path for

Table 1. Measures of Efficiency*

Cost-efficiency

1. Reserve plant margins (20%)
2. Plant availability factors (85 to 90%)
3. Total systems losses (6 to 10%)
4. Fuel efficiency (kcal/kWh)
   - coal (2,300-2,800)
   - oil (2,300-2,700)
   - gas turbines (2,500-2,000)
   - combined cycle (1,700-2,000)

Price-efficiency

1. Real financial rate of return (8 to 12%)†
2. Self-financing ratio (>25%)
3. Billing efficiency: thefts (<2%), collection period (<30 to 40 days)
4. Percent share, equity, and bond finance
5. Demand management:
   - load factor improvement policies
   - power factor improvement
   - peak load pricing
   - pricing by voltage level

Provision of service

1. Loss of load probability (7 hours per year)
2. Percent of public served (rises with per capita income level and costs and benefits of electrification; long-term goal is universal provision)
3. Compliance with environmental policies (varies and evolves with policies, but high levels of abatement can be achieved through control technologies for PM, NOx, and SO2 or use of "clean fuels" such as gas)

* Best practices standards, based on the "indicators of performance" drafted by the World Bank's energy staff, February 1994.

† These rates of return are lower than the returns of 20 percent often quoted by private companies, which include allowances for cost escalation and slippages, and also for country risk in the case of foreign investors. The *expected* or average real financial returns are very likely much lower, comparable to the average real financial return of 8 to 12 percent.

moving from one model to another may be as important as the choice of the model itself, and will vary with the situation. Some countries might initially prefer *Model II* (the traditional utility operating on commercial principles, with competitive procurement of new generation), and shift to *Models III* or *IV* at a later time. Others might be concerned with rigidities setting in once a decision has been made to set up a competitive arrangement between the public utility and private producers under *Model II*, and therefore might prefer to go directly to *Model III* or *IV*.

The path chosen will depend on the capacity and willingness of the capital markets to support the reforms. In developing countries, the stock markets presently have a capitalized value of about $800 billion and are raising an additional $65 billion each year—only about half the electricity industry's annual new investment requirements of $120 billion, and of course there are the financial demands of other sectors to be met. Even when aggressive policies are put in place to change the legal framework and corporatize the industry, the transition to full private ownership cannot proceed faster than the private sector's ability to finance it.

In turn, availability of finance will be affected by the following:

- the inheritance, in most countries, of capacity shortages, overloaded distribution systems, large losses, thefts of supplies often amounting to over 20 percent of electricity produced, much generating capacity in disrepair, and numerous managerial problems—including overmanning and dealing with redundancies—to be sorted out. This will deter private acquisition of the existing assets unless their prices are bid down to a low level.
- rising demands for new capacity. The amount of new investment required in the decade after privatization will probably exceed the size of the existing system. New investors may be more attracted to supplying new capacity than to acquiring and rehabilitating the existing system. If so, it would be at least a decade before the majority of the system could be privately owned, even in theory.
- the large numbers of people and small commercial consumers without service. Roughly 2 billion people do not have access to electricity in developing countries, and with population growth and urbanization the demand for new connections will be high.
- the need to raise prices by 50 to 100 percent or more in many countries.
- fears of nationalist backlashes against foreign ownership. Local capital markets will not be able to absorb the industry fully, and finance will be forthcoming from foreign buyers only if political and economic risks are low.

The danger is that if these problems are not addressed privatization may not be sustainable, and there may be calls for renationalization—a possibility that the investors will doubtless have in mind. As one private producer has put it, their fear is that "nationalization will not be an intermediate step between privatization and privatization, but that privatization will be an intermediate step between nationalization and nationalization." All the more reason, therefore, to choose the model and the path of reform carefully.

[1] This Note has especially benefited from materials and comments provided by Bernard Tenenbaum, John Besant-Jones, and Peter Cordukes.

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