Bulk Electricity Pricing in Restructured Markets

Lessons for Developing Countries from Eight Case Studies

Robin W. Bates and London Economics (Consultants)
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Preface

In November 1992, the World Bank’s Board of Directors approved a single set of “good practice” principles for the power sector, outlined in two Bank Board papers (World Bank 1993a, b). The Bank announced that it would lend for electric power only where countries had demonstrated a commitment to effective operation in the sector, as evidenced by a resolve to achieve six key objectives: (1) transparent regulation; (2) commercialization and corporatization; (3) importation of electric power services, both from developed and more advanced developing countries; (4) private involvement; (5) market pricing; and (6) demand management.

In light of the 1992 papers, and given the continuing efforts of countries around the world to reform their sectors in line with these principles, the Bank saw substantial value in surveying and reporting on the experiences of both developed and developing countries with the process. A compilation of empirical and anecdotal information on the problems, perceptions, and successes of countries that had completed or were still pursuing power sector reforms could be useful to countries contemplating or initiating reforms of their own development strategies, institutions, and pricing policies for the sector. The results of an information-gathering effort, it was felt, would also be useful as feedback to World Bank staff involved in assistance and lending to the power sector.

An effort to update the documentation of sector reform efforts—particularly with regard to bulk electricity pricing—was seen as particularly important now. Although electricity pricing is well understood in the context of traditional, monopolistic state-owned enterprises, this is not so where power utilities are undergoing commercialization, decentralization, and privatization. Bulk electricity pricing appears to be a crucial factor that will determine the success and sustainability of restructuring, since it plays the major role in the profitability and financing of generation and transmission and the allocation of economic resources between alternative investments, including their location.

Recognizing this need for information, the Bank implemented a study of the pricing of bulk electricity supplies in restructured markets. The work focused on countries where the reform process has already made substantial advances: the United Kingdom, Norway, the United States, and Chile. Field work for case studies was carried out in 1994 under financing from the World Bank and the U.K. Overseas Development Administration, directly and through the Joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP).

The ESMAP task manager was Robin Bates, principal energy economist in the Industry and Energy Department, Power Development, Efficiency and Household Fuels Division, of the World Bank. London Economics was the main consultant. The London Economics team was directed by Michael Webb and included Jamie Carstairs, Seabron Adamson, Gil Yarron, David Harbord, and Nils Henrik Morch von der Fehr. Umesh Chandra contributed to the sections on investment and small systems.

The full study is available in three volumes (London Economics 1995). The present paper is intended to highlight the principal results in briefer and somewhat less technical form.
Acknowledgments

The authors gratefully acknowledge the generous support of many individuals in all the countries covered by the case studies. The assistance they gave freely to the World Bank and London Economics team in carrying out the field work was literally invaluable. Acknowledgments are also made for the advice, support, and comments of numerous World Bank staff from inception of the work right through to completion of the final report, including Karl Jechoutek, Trevor Byer, John Besant-Jones, Hernan Garcia, Peter Cordukes, Lazlo Lovei, Manuel Dussan, Jean-Pierre Charpentier, Rafael Moscote, Bernard Tenenbaum, and Henri Bretaudeau. Thanks also go to Paul Wolman for editing and managing the production of the paper.
## Abbreviations and Acronyms

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<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tr>
<td>CFD</td>
<td>contract for differences</td>
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<tr>
<td>CNE</td>
<td>Comisión Nacional de Energía (National Energy Commission; Chile)</td>
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<tr>
<td>MAPP</td>
<td>Mid-Continent Area Power Pool (United States)</td>
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<td>MW</td>
<td>megawatt</td>
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<td>CDEC-SIC</td>
<td>Centro de Despacho Económico de Carga – Sistema Interconectado Central (Economic Load Dispatch Center of the Central Interconnected System; Chile)</td>
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<tr>
<td>NEPOOL</td>
<td>New England Power Pool (United States)</td>
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<td>NIE</td>
<td>Northern Ireland Electric</td>
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<td>PPM</td>
<td>power procurement manager</td>
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<td>PPP</td>
<td>pool purchase price</td>
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<td>PSP</td>
<td>pool selling price</td>
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<td>REC</td>
<td>Regional Electricity Companies (U.K.)</td>
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<td>SHE</td>
<td>Scottish Hydro-Electric</td>
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<td>SP</td>
<td>Scottish Power</td>
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<td>SIC</td>
<td>Sistema Interconectado Central (Central Interconnected System; Chile)</td>
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<td>SMP</td>
<td>system marginal price</td>
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<td>SRMC</td>
<td>short-run marginal cost</td>
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<td>UNDP</td>
<td>United Nations Development Programme</td>
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<td>ESMAP</td>
<td>Energy Sector Management Assistance Programme</td>
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<td>FCC</td>
<td>Florida Coordinating Group (United States)</td>
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<td>FERC</td>
<td>Federal Energy Regulatory Commission (United States)</td>
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<tr>
<td>IPP</td>
<td>independent power producer</td>
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<td>kW</td>
<td>kilowatt</td>
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<tr>
<td>LOLP</td>
<td>loss-of-load probability</td>
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<td>LRMC</td>
<td>long-run marginal cost</td>
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1. Background

Governments in various parts of the world, including those in developing countries, are now reforming their power sectors in order to strengthen their performance. The goals are to improve the extent to which the sector covers its costs, the efficiency with which it produces electricity and delivers it to consumers, and the efficiency with which the consumers themselves use the power. Experience in different parts of the world has demonstrated that large performance improvements in the production, delivery, and consumption of electricity are difficult or impossible to achieve without reform. The restructuring of electricity markets is an essential ingredient of the reform process.

Why Developing Countries Are Restructuring

Traditionally, the power sectors of developing countries were structured as vertically integrated public monopolies—that is, as a single national electric utility operating generation, transmission, distribution, and supply in a fully integrated (“bundled”) system. The economic theory underlying this model of sector structure posits that the central authority is best placed to construct and operate generating plants at least cost and to ensure that investment takes place on a scale sufficient to satisfy final demand. Underlying the optimization process is the assumption that investment decisions rely on a discount rate that reflects the opportunity cost of capital. Prices at each voltage level are set on the basis of long-run marginal cost (LRMC), taking into account time-of-day and seasonal factors as well as geographical variations in cost. A model emphasizing the state’s overarching role has been attractive to governments in developed and developing countries because of the highly illiquid nature of investments in electricity plant, the lengthy gestation of system planning and construction, the relatively long life of assets, the scarcity of technical and managerial skills to operate complex power systems, and the interdependence of plant operations in an electrical network.

Unfortunately, the traditional model in practice often did not live up to its theoretical promise. Problems arose in estimating basic parameters (e.g., demand and fuel prices). Generation projects were not necessarily selected according to least-cost criteria. Prices were often influenced by political considerations. Cross-subsidizations among consumers and supply functions were common. Thus, despite utilities’ continuing need for self-sustaining income, average real power tariffs in developing countries were allowed to fall from US$5.2/kilowatt hour (kWh) to US$3.8/kWh between 1979 and 1988. Financial performance declined commensurately: for example, rates of return on assets fell from levels averaging 9 percent before the mid-1970s to less than 5 percent by the beginning of the 1990s (World Bank 1993b, p. 12). Not surprisingly, the quality of service suffered, technical and nontechnical losses and fuel consumption remained high, and poor maintenance persisted. At the same time, the macroeconomic situations in developing countries deteriorated. In particular, it was evident that high-priority social needs were competing for limited budgets and would severely reduce the availability of public funds to finance the mounting need for planned power sector investments. In fact, the World Bank estimated that about US$1 trillion would be needed to finance expansion programs for electric utilities in the developing countries in the 1990s, and this figure was seen as approaching US$2 trillion in the first decade of the next century (Stern 1995).

How Developing Countries Are Restructuring

More and more governments in developing countries have recognized that the traditional model for the market structure of power sectors is essentially unsustainable. Reform and restructuring efforts therefore have focused on the central institutional deficiency in the traditional model—that public sector monopolies are treated as a direct extension of government, preventing distinctions from being made between the functions of ownership, regulation, and management. Recognizing that the blurring of these functions has largely subverted competition, governments in Latin America, Asia, Africa, and Central Europe have sought to restructure their electricity markets. Centers of activity include Chile and Argentina; Malaysia, the Philippines, and the Indian state of Orissa; Ghana and Morocco; and Turkey, Hungary, and
Ukraine. Except for Chile, which had completed its reforms by 1988 and is regarded as a pioneer in restructuring, the reformers have relied substantially on the experience in the United Kingdom, the United States, and Norway in seeking alternatives to the traditional model.

Countries that are restructuring have typically sought two fundamental institutional changes: the removal of government from key decisionmaking areas; and greater competition (Bacon 1995, p. 1). The former change can start with the commercialization and corporatization of the vertically integrated public monopoly. Toward that end, management must be required to establish independent cost and profit centers within the company; pay interest and taxes; earn commercially competitive rates of return on equity; and face hard budget constraints. In turn, management must have some independence in personnel policies, notably in hiring and firing and in setting wages and salaries. Management also must have the autonomy to carry out procurement on commercial principles and to set prices, within regulatory requirements. The government can remove itself even further from the arena by privatizing some or all of the electricity sector.

Although commercialization, corporatization, or privatization of a public monopoly can, in itself, increase efficiency and improve resource allocation, further gains are anticipated from the introduction of competition through the unbundling of power system components. Vertical unbundling involves the separation of two or more parts of the integrated system: generation, transmission, distribution (sometimes called "the wires business") and supply (sales to final consumers). Horizontal unbundling could in principle cover one or more entities in generation, distribution, and supply. Transmission usually is not included here; it is regarded as a natural monopoly because of the need to preserve integrated electrical operation and the importance of economies of scale.

At the generation level, horizontal unbundling allows power plants to compete with one another for sales, at least to major consumers. Of course, intermediaries—brokers or suppliers and several distribution entities—can provide electricity to final consumers, at least on a geographical basis. Where the state retains monopoly ownership of the transmission and distribution system, independent power producers (IPPs) can sell to a state purchasing monopoly.

A further dimension of competition achieved through unbundling is that it can foster international electricity trade. In a public monopoly market, political considerations are likely to overshadow commercial ones, and that tends to eliminate a potential driving force for international interconnections—seeking a commercial advantage by buying and selling electricity on the international market.

Of course, effective restructuring of power markets of any size cannot take place without proper regulation, and that remains an appropriate role for government. It is a government's responsibility to protect the interests of consumers and to set the rules of the game so that private investors can have sufficient confidence to enter the sector. The government must ensure competition; and, where competition is weak or absent, it will need to play some role in setting prices and conditions of service, such as in distribution and transmission.

Finally, if efficiency and reduced transaction costs are to result from unbundling, transparent relations must be introduced between generation, transmission, and distribution, in terms of the pricing of generation and transmission services and in terms of mechanisms to ensure the adequacy of new investments.
2. Methodology for the Work

As noted in the preface, the research for this paper was motivated first of all by the perceived need to cast more light on the variety of ways in which restructuring and revised pricing processes have been implemented in various parts of the world.

An Approach Based on Eight Case Studies

The methodology of the study was to select case studies for eight power systems in four countries: the United Kingdom, the United States, Norway, and Chile. These countries were chosen partly because their reform processes were judged to have proceeded far enough to provide an adequate empirical basis for conclusions about other countries. Although only Chile among the study countries could be characterized as “developing,” the sample collectively comprises a wide range of relatively recent experiences, and the cases are often cited as models of reform in the power sector. In addition to the system in Norway, the cases covered Chile’s Central Interconnected System (Sistema Interconectado Central; SIC); three systems in the United Kingdom (England and Wales, Northern Ireland, and Scotland); and three in the United States (the Mid-Continent Area Power Pool, MAPP; the New England Power Pool, NEPOOL; and the Florida Coordinating Group, FCG). The analysis was confined to bulk pricing issues because experience with market restructuring in these countries and elsewhere has been much more limited with regard to small consumers.

Characteristics of the Case-Study Systems

The sizes of the power sectors chosen for the case studies were important, because they governed the options for competition in bulk generation. The smallest power sector examined was Northern Ireland, with 2,400 MW installed. Chile was also relatively small, with 5,000 MW. Scotland had 12,000 MW, although peak demand was only about 5,700 MW. The other power sectors were much larger: in the range 25,000 to 42,000 MW for the three U.S. systems; 27,000 MW for Norway; and 55,000 MW in England and Wales.

The generation technologies adopted in the systems were also important, as they affected the costs and operating characteristics. The smallest case (Northern Ireland) and the largest (England and Wales) were effectively all thermal, although the latter had some pump storage. The Norwegian power sector was mainly based on hydroelectric generation. Chile also had a high share of hydropower, accounting for 70 percent of capacity, whereas Scotland’s share was only about 20 percent. The cases in the United States varied widely in technology: MAPP had 65 percent coal-fired capacity in the United States proper, but 71 percent was hydroelectric in Canada; NEPOOL had 40 percent nuclear capacity; and the FCG was dominated by thermal capacity that included coal, oil, and gas.

Institutional Structures of the Case Studies

The institutional structures of the power sectors chosen for the case studies were important because they had a profound effect on the approaches to pricing. If power sectors are vertically separated, and in particular if generation and transmission are separated, then some form of commercial arrangement is needed for bulk generation. If the generation sector is horizontally separated—that is, if several generation companies or cost centers with reasonably similar SRMCs are in operation—then scope is available for allowing competition to govern pricing in generation and supply, as opposed to some more administrative approach to pricing.

All of the case studies had some degree of unbundling. However, some case studies retained a substantial amount of vertical integration, sometimes by design and sometimes not. Scotland has two vertically integrated utilities, although the generation, transmission, distribution, and supply businesses were required to prepare independent regulatory accounts. All the U.S. pools also exhibited some degree of vertical integration. However, in an interesting variation, the FCG had the highest degree of vertical integration, with only limited trade at the margin. NEPOOL, on the other hand, adopted centralized dispatch, with an important role for trade. Norway had
a mixed system, including a large number of vertically inte-
grated utilities that maintained separate accounts for the dif-
cerent functions. England and Wales, Northern Ireland, and 
Chile all had a relatively high degree of vertical separation. In 
some cases, concerns arose about the possibility that vertical 
reintegration would affect the approach taken to bulk pric-
ing. For example, in England and Wales, the Regional Elec-
tricity Companies (RECs), which were responsible for dis-
tribution, had made investments in generation. In Chile, 
the largest generator also owned transmission.

The degree of horizontal integration also underpins the ap-
proach to bulk pricing. If several generators with reason-
ably similar operating costs are in the market, then the bulk 
price can be set through competition. Within the case stud-
ies, England and Wales and Norway had gone furthest in 
introducing competition in generation. In both cases, con-
cerns surfaced about undue market power. In England and 
Wales, the two largest producers—National Power and 
PowerGen, with about 47 percent and 32 percent of total 
capacity, respectively—dominated generation. In Norway, 
the largest producer—Statkraft, with about 30 percent of 
capacity—displayed considerable market power. In Chile, 
46 percent of generation was owned by one group. In 
none of the cases had horizontal unbundling yielded full 
competition at the retail level. Nevertheless, in England 
and Wales, Chile, and Norway, power producers did com-
pete to supply large final consumers (at that time defined 
as having loads above 100 kW in England and Wales and 2 
MW in Chile).

The power sectors examined were mainly in private own-
ership, although public ownership was not always excluded. 
Generation was partly publicly owned in Chile, England 
and Wales, Scotland, and Norway, as was transmission in 
Norway. Distribution was partly in public hands in Norway 
and the United States. The reform process itself was also of 
interest. Some countries had made major changes in their 
approach to the power sector, whereas others had adopted a 
more gradual approach. The objectives of power sector re-
form also appeared to vary. Although the prime goal was 
usually raising finance, and sometimes increasing efficiency, 
the United States had a particular focus on reliability.

Both Norway and England and Wales introduced “open” 
pools; that is, they created bulk power trading systems that 
allowed customers and traders as well as generators to join. 
In Norway, this represented less of a sea change, since its 
system developed from a generator trading arrangement 
designed to optimize energy storage levels within a hydro-
electric system. In addition, considerable public ownership 
was retained. In England and Wales, market reforms were 
introduced in connection with other changes, including 
privatization of all generation capacity other than nuclear. 
Chile and the United States pursued more gradual reform.

In all cases, however, the sectors continued to make adjust-
ments to market structures. These adjustments are probably 
occurring most rapidly in the United States at present, as 
increasing competition at the retail level is causing major 
changes in market structure and regulation.
3. Main Issues Illuminated by the Case Studies

The eight case studies served to cast light on five crucial issues with regard to unbundled systems: (1) setting of bulk supply prices for generation; (2) contracts and their relationship with economic efficiency in operation; (3) pricing of transmission services; (4) adequacy of investment on the scale required to satisfy demand, given the long gestation of projects and the high profile of electricity supply in the political economies of developing countries; (5) potential problems with regard to system size and transaction costs.

The main findings with regard to these five basic questions are outlined in the subsections below. However, it must be emphasized that practices for bulk pricing in competitive markets are evolving rapidly. The findings reported here were valid in 1995, but important changes are under way—for example, in the U.S. and the U.K. electricity markets. Valuable experience is also accumulating in other countries, notably Argentina. These developments may mean that the specifics of the descriptions given in the eight case studies may not apply exactly to those eight systems today, but they should not invalidate the paper’s historical findings.

1. Setting of Bulk Supply Prices for Generation

As noted, the calculation of LRMCs plays a significant role in pricing decisions in the traditional model of the power sector. However, the prices that would emerge from such a calculation are essentially theoretical, even where sophisticated simulation techniques are used. In unbundled systems, in contrast, bulk supply prices for generation result from market forces and commercial considerations. It should be noted, though, that the process varied widely in the case studies.

From an economic point of view, market forces will produce an efficient solution if bulk electricity prices lead to the least-cost operation of the power system, in terms of the optimal dispatch of generating plants in the short run and the level and mix of power plant investment in the long run. In the short run, optimal dispatch should be by merit order, based on short-run marginal cost (SRMC). In a fully optimized power system, SRMCs and LRMCs are equalized; at the margin, it will cost as much to dispatch existing plant (counting only its operating costs) as new plant (counting both operating and investment costs), in the sense that at the margin the operating cost savings of new plant will just offset its investment cost. This section examines how two types of restructured markets may or may not lead to the economically efficient dispatch of generating plants. Issues related to investment are considered later.

Power Pools: The England and Wales System

Power pools based on competitive bidding are presumed to lead to optimal dispatch decisions because spot prices should be driven down to the level of SRMC. The need for formal regulation of bulk electricity prices is reduced to a minimum and largely replaced by market forces. The system in England and Wales is frequently cited as a favorable example of this type of bulk power pricing (although even there problems have arisen). In the pool system, power is sold into the pool at half-hourly intervals at the pool purchase price (PPP), which is the main component of generator pool revenues. Power is bought from the pool by suppliers—principally the RECs, but also by large consumers—at the pool selling price (PSP). The PPP has two components: the system marginal price (SMP) and a payment related to the loss-of-load probability (LOLP). The latter is a capacity payment designed to cover the capital costs of providing sufficient capacity to maintain system security—that is, to avoid loss of load. Both components of the PPP are paid to each generating unit dispatched and running in any particular half-hour. The difference between the PPP and the PSP, called the uplift, is paid to specific generators to cover the costs of (1) transmission losses; (2) any ancillary services, such as frequency control and reactive power, that they may be called on to provide; (3) sets scheduled to provide reserve; (4) sets available but not scheduled for energy or reserve; and (5) sets run or not run as a result of transmission constraints that otherwise would not or would have been dispatched.

Such a bidding system will meet the objectives of least-cost dispatch, provided that bids are at SRMC and constraints
on transmission capacity do not prevent generating plants from operating according to merit order. However, in England and Wales bids apparently could be lifted above SRMC for substantial periods because of the dominance of the two largest generators. As a result, the regulator intervened in the market in two ways: (1) by introducing an effective price cap on the pool price for electricity, indicating that competition could not be relied on to minimize costs (the price cap was removed in 1996); and (2) exerting pressure on the generators to sell capacity and create a more competitive market. Inefficient pricing of transmission has also “constrained on” high-cost generating plant.

An “Intermediate” Approach: The Chilean System

A particularly interesting approach that can be characterized as intermediate between the traditional power sector model and the highly competitive pool approach has been implemented in Chile. The Chilean model attempts to set the marginal value of power and energy without the use of competitive bidding. Under the model, generators receive separate payments for energy and power, both of which are based on reference costs. Furthermore, the model is based on two types of final consumer: “free clients” (i.e., those with at least 2 MW of demand) are theoretically permitted to purchase from any generator or distributor; “small customers” (i.e., those with less than 2 MW of demand) must buy from their local distributor at a regulated price. The distributor, in turn, purchases from a generator at a regulated bulk price, the node price.

The key energy pricing mechanism in the Chilean model is a theoretical calculation of the system SRMC. The calculation is made, on an hourly basis, by an independent regulatory authority, the National Energy Commission (Comisión Nacional de Energía; CNE). Computer-based models are used to identify the SRMC resulting from least-cost system operation. It depends on three factors: (1) the value of water stored in Lake Laja (which holds some 30 percent of annual energy and serves as a replacement for thermal generation); (2) the declared availability of generating units and the audited costs of thermal plant; and (3) the addition of new generating capacity to the system to meet growing demand.

The optimal system operation over 48 months is calculated as that with the minimum present value of operating and rationing costs, using a 10 percent discount rate. Rationing costs have to be included, as some probability exists of failing to meet demand—mainly because of the threat of exceptionally dry years and the consequent lack of hydroelectric power. Data on hydrological conditions over the past 40 years are used to simulate the range of likely future system operating conditions. Possible SRMCs range between zero (when no thermal plant is run and water would be spilled) and the cost of anticipated outages (when no hydroelectric peaking plant could be run).

SRMC affects bulk electricity prices in the Chilean electricity market in three important ways. First, it forms the basis for the decisions of the Economic Load Dispatch Center for the Central Interconnected System (Centro de Despacho Económico de Carga – Sistema Interconectado Central; CDEC-SIC). In operating the pool, CDEC dispatches only those generating units with audited costs below the SRMC to meet demand. An important corollary is that, fundamentally, the optimality of dispatch decisions depends on CNE’s evaluation of the opportunity cost of stored water and the accuracy of audited costs rather than on the market test of competitive costs. Second, generators are permitted to buy and sell energy from each other through the pool, at the SRMC. Third, the SRMC is a key reference point for the regulated bulk price for sales of electricity to distributors.

The SRMC is used to determine the regulated bulk energy price in the following way. The projected four-year weighted average SRMC is published by the CNE every April and October. Within this six-month period it is fixed, unless inflation exceeds 10 percent (triggering automatic indexation). Thus, the regulated bulk energy price is the weighted average of the projected SRMC over a 48-month period. It will be apparent that a major determinant of the forecast SRMC is the expected availability of water. It is important to note that the regulated energy price actually paid to a generator at any delivery point (or node) is adjusted for the marginal costs of transmission.

In addition to receiving a price for energy based on SRMC, generators are paid a peak power price. The peak power price is derived from the annualized investment and fixed operating costs of adding a 50 MW gas turbine to the system to meet the highest point of peak demand in the previous year. Payment is made on the basis of a generator’s firm capacity (evaluated at the start of the year) and the monthly availability of this capacity. Evidently, capacity payments should be related to the probability of capacity shortage, as in England and Wales. However, the Chilean system ap-
pears to overcompensate generators through double-counting, since the regulated energy price already includes an estimate of rationing costs. As in the case of the energy price, the capacity price received by the generator at any node is adjusted to allow for transmission costs. These payments are limited by the Electricity Law, which requires that the regulated price should not differ from the unregulated price to “free clients” by more than 10 percent.

The existence of the unregulated market in Chile, like the competitive pool in England and Wales, in theory plays an important role in ensuring that bulk prices reflect the SRMC. On the other hand, the case study found no clear evidence that generators had pursued “free clients” aggressively as customers. One impediment appeared to be the system of transmission pricing, especially the problem of setting the basic toll. Another obstacle comes from the limited unbundling that has in fact taken place in Chile: for example, a large distributor is also a supplier and a shareholder in a major generating company. By and large, information on the prices established for “free clients” is confidential, but the limited evidence available suggests that they tended to pay the regulated price plus a mark-up (as appropriate) to cover subtransmission and distribution costs.

2. Contracts and Economic Efficiency

Evidently, any bulk pricing system reflecting SRMCs must show considerable volatility on an hourly, daily, and seasonal basis. This volatility is appropriate from an economic standpoint—it communicates to consumers the fact that the costs of serving them depend on when they want to be supplied. In financial terms, however, this volatility poses considerable risks for producers and consumers alike. Contracts can reduce these risks, but where they influence dispatch decisions, contracts also can be presumed to interfere with the least-cost operation of power systems.

Contracts play a key role in providing stability in reformed power sectors. They take many different forms, although a basic distinction can be made between physical and hedging (financial) contracts. Physical contracts may take several forms, including (1) long-term contracts for supply of firm energy; (2) short-term contracts for marginal trade on an opportunistic basis; and (3) contracts for emergency supply, to provide additional security. Hedging contracts may mirror the features of physical contracts but emphasize the stabilization of financial parameters such as prices.

The case studies included examples of all these contracts: (1) long-term contracts are important in the pools covered by the study in the United States, in Norway and in Northern Ireland; (2) short-term contracts for marginal trade exist between Scottish Hydro-Electric (SHE) and Scottish Power (SP) and within the studied U.S. pools; (3) contracts for emergency supply are prominent in NEPOOL and MAPP; and (4) hedging contracts are widespread in the England and Wales system.

Long-term contracts are the most likely to interfere with economic efficiency in the operation of unbundled systems. Yet generators need to make long-term investments, with low resale values, and they may enter “take or pay” contracts for fuel. They face a risk that bulk energy prices will not cover their costs. On the other hand, suppliers and distribution companies face a risk that bulk energy prices will rise, leaving them with fixed-price contracts with consumers that are loss-making. Generators, suppliers, and distributors can hedge these risks through long-term contracts for bulk supply.

Hedging contracts should not be confused with contracts to run a power station. Under the former, purchasers are interested in the price and quantity of electricity, as well as in the reliability of supply, but they are not interested in which power station is running to meet their contract, and indeed cannot tell this when drawing from the grid. They therefore enter financial contracts for bulk electricity, not physical contracts to run a power station. Where contracts exist to operate power stations, they can form the basis of dispatch. For example, if the owner of a coal-fired generator has a contract to supply 200 MW between the hours of 8 a.m. and 9 a.m., the plant could be run during those periods. This does indeed form the basis of dispatch in many systems. For example, in Norway power sold under long-term contracts is dispatched, subject to transmission constraints. Approximately 80 to 90 percent of demand is covered by long-term contracts, so dispatch is largely determined by the generators’ contractual commitments.

However, long-term bilateral financial contracts cannot be the basis for all dispatch. Dispatch is concerned with ensuring stability and minimizing costs in the short term. It would not be possible to write a long-term contract that was sufficiently detailed to cover all combinations of available generation, demand, and transmission capacity for all periods. As a result, marginal plant dispatch decisions need to be separated from contracts.
One way to do this is through the writing of contracts for differences (CFDs), as has occurred in England and Wales. These contracts, as their name suggests, cover the difference between an agreed (or "strike") price and a reference price, for a specified quantity of energy. Thus, all CFDs have three elements: a strike price, a reference price, and a quantity. A contract may use any component of the PSP as a reference price. Most have been written against the PPP and do not cover uplift.

Most of the CFDs originally signed in England and Wales were “one way” CFDs. Under these contracts, a generator effectively guaranteed price stability to the supplier for a given volume of energy by making periodic payments to the supplier whenever the pool price exceeded the strike price. The payments were equal to the difference between the pool price and the strike price, multiplied by the contract quantity (in megawatt hours). In exchange, the generator received an option fee, fixed annually. These contracts gave suppliers cost certainty, at least for part of their bulk energy needs, and gave generators certain revenue, in the form of the option fee. Later, “two way” CFDs became more popular. These contracts in effect fix a price for electricity purchases and sales. Rebates from the generator to the supplier are made as before, when the pool price is above the contract strike price, but the supplier also pays rebates to the generator when the pool price is below the contract strike price. No option fee is typically paid under such contracts.

CFDs are often complex. They may have multiple strike prices for different times of day or periods of the year, and contract volumes may be “sculpted” over the course of the year. Furthermore, some contracts can only be “called” during certain periods, such as peak times or night hours. As a result, the supply businesses may face difficulties in matching the timing and amount of kilowatt hours and kilowatts in their CFDs with their own load shapes. A further consequence is that the market becomes relatively illiquid. CFDs may be too complex and too tailored to the needs of particular suppliers to be traded easily.

As an alternative to CFDs, structures can be created for generators to trade around the contracts, and so to realize optimum dispatch. All three U.S. pools in the case studies had “hour ahead” markets for short-term trade. The volume of trade required to achieve least-cost dispatch might be relatively slight. In Norway, only 10 to 20 percent of energy is traded. In Scotland, and in some of the U.S. pools, trade has been even less—in some cases, less than 1 percent of total energy. The case study for FCG found that only 0.1 percent of energy in Florida was traded through that group.

Only one of the case studies covered a situation where long-term contracts were the sole basis of dispatch. In Northern Ireland, all generators had bilateral contracts with the power procurement manager (PPM), who dispatched the plant, purchased all bulk electricity, and sold electricity to distribution businesses and large consumers under a bulk supply tariff. The generators had long-term contracts, covering the life of the plant, that were two-part contracts—for capacity and energy. Capacity payments were made on the basis of availability. Provided that availability targets were met, they were designed to cover fixed operating costs, depreciation, and a return on assets. Target availability rates were based on past performance. An incentive thus existed to improve availability and gain additional payments. Availability rates have been high, along with a high reserve margin. Energy payments were designed to cover the SRMC. They were initially set on the basis of the actual SRMC but were later indexed against appropriate fuel prices. Provided that energy payments are correctly set in the first place and properly indexed, they can form the basis of optimal dispatch decisions.

A system of this kind provides good incentives for generators to minimize energy costs either through efficient energy purchase or through increased thermal efficiency. As a result, it may increasingly diverge from allocative efficiency, since generators will be able to sell energy above their cost of production. Providing incentives for productive efficiency through a fixed and indexed energy charge needs to be balanced against passing on some of those gains to consumers. This is done through periodic resetting of the fuel index.

In Northern Ireland, concerns have arisen that the fuel price indexes have been inappropriate. Generators have been able to purchase fuel below the indexed price and make high profits. Poor indexation could also cause divergences from productive efficiency. This would happen if one company had a contract energy charge above a second generator, but its actual costs were lower. This is unlikely to happen in Northern Ireland because power stations are few, and they have very different operating costs.
3. Pricing of Transmission Services

In an unbundled system, the pricing of transmission services plays a key role in determining the dispatch of generating plants, according to their location relative to the load. In the traditional power sector model, vertical integration makes it possible to take transmission costs directly into account. Bulk consumers only have to face bulk prices, which already include the transmission component. Unbundling requires a formal transfer mechanism to mediate between producers and consumers. In most of the case studies, transmission pricing was handled in a much less satisfactory way than generation.

Two important issues arise with respect to transmission. The first is the need to reconcile efficient pricing with financial viability; and the second is the need to provide incentives for least-cost expansion of the transmission network. An economically efficient tariff will reflect the marginal costs of transmission, which comprise (1) congestion costs—that is, running generating plant out of merit order because of transmission constraints; (2) marginal losses, which will be substantially higher than average losses; and (3) marginal capacity cost, reflecting the probability of loss of load in the transmission network and corresponding to the loss-of-load measure for generation discussed above. Incorporating these costs properly in the pricing of transmission services would lead in principle to economically efficient transmission tariffs. However, sufficient revenue would not normally be collected to maintain, operate, and expand the transmission network. As a result, additional funds have to be raised to cover the substantial fixed-cost element.

Many of the case studies had relatively unsophisticated transmission pricing mechanisms, which gave poor marginal cost signals. For example, in England and Wales, congestion costs and losses were averaged into the pool selling price, which included the cost of generators that are “constrained on” and “constrained off” the merit order, because of transmission limitations. In Norway, on the other hand, a more successful effort had been made to account for these costs through the setting of different prices in six regional “subpools.”

Norway unbundled the transmission system from the main generator and created an independent system operator. Open access to the transmission system was guaranteed to all generators, and an effort was made to price transmission services to maximize efficient use of the grid, subject to the constraint that revenues from transmission tariffs should balance the costs of operating, maintaining, and extending the grid.

The system of transmission charges had four different elements: two fixed charges (a connection charge and a power fee) and two variable charges (an energy charge and a capacity fee). The connection charge was intended to relate to the reliability of the transmission grid and was applied to all available winter power generation capacity and all power consumption (less interruptible loads) during the hour of maximum consumption. It was estimated that about 15 percent of the total network cost could be attributed to this heading. The power fee was determined residually, so as to secure the financial viability of the transmission system. It was applied on the net kilowatt input, or output, from the grid under maximum load conditions. The energy fee was based on estimated marginal losses, which were generally double the average losses. Marginal losses were estimated for each of six different regions (groups of nodes) and distinguished between three tariff periods (light load, heavy load during the day, and heavy load during nights and weekends). The fee for compensation of losses was calculated by multiplying the marginal loss percentage by the relevant spot market price of energy. Finally, the capacity fee was intended to reflect transmission constraints on the network. In 1993, the variable system charges accounted for less than 17 percent of the total revenue earned by the transmission system operator. The remaining 83 percent came from the fixed charges.

Although the Norwegians have encountered problems in implementing prices to meet the criteria of efficient operation and financial viability, so far their system of transmission pricing seems to have been reasonably successful. The main uncertainty has concerned whether or not the existing regulatory regime provides adequate incentives for the economically efficient expansion of the grid. On the other hand, as transmission capacity is adequate at present, the efficiency of the system with regard to investment incentives has not yet been tested.

In the U.S. pools examined, losses were accounted for primarily in contracts rather than in the tariff. Investor-owned utilities selling energy beyond state boundaries are subject
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to federal regulation. The Federal Energy Regulatory Commis-

tion (FERC) must approve all transmission and wheel-
ing charges, and it reviews the activities of investor-owned

utilities buying and selling energy. The basic principle of

FERC's regulation has been that the price of all energy or

transmission services must be cost-based—that is, based on

marginal fuel and maintenance costs plus the recovery of

historic fixed costs.

Traditionally, FERC's pricing policy allowed transmission

charges for firm transactions (i.e., noninterruptible) to yield

revenues adequate to cover embedded costs. This was achieved

using a "postage stamp" basis—that is, it was not distance sen-
sitive. For nonfirm transactions, rates reflected variable costs

plus a contribution to the fixed costs of the network, ac-
cording to the degree of interruptibility. Both methods were

based on contract paths rather than on the actual flows of
electric power through the transmission system.

FERC later amended its policies to reflect the occasional

need for utilities to expand their transmission systems be-
cause of outside transactions. Utilities were then allowed to

charge customers that were only making use of transmission

services the higher of the embedded costs (for the system

as expanded) or the incremental expansion costs, but not both.

If transmission constraints exist, the transmitting utility can

charge the higher of the embedded costs or the "verifiable

and legitimate" opportunity costs, but not both.

Transmission pricing in Chile is among the most market-

oriented in the world. The regulated energy price actually

paid to a generator is adjusted for the marginal costs of

transmission. As explained previously, the node price is

the regulated price at different locations in the system, ad-
justed for transmission losses.

In Chile most electricity generation is in the South of the

country, whereas the main loads are in the North and Cen-
ter. Energy injected into the system in the southern part of
the country is penalized for marginal transmission losses; for
bulk sales to a distributor in the Center the price received
by a generator in the South is reduced by the difference
between the output and input node penalty factors. Mar-
ginal transmission losses for the system (evaluated during
times of peak demand) are lowered by energy injections in
the North. Consequently, generators who add energy in
the North for delivery to the Center are paid an additional
sum for the benefit this provides to the transmission system.

In addition to paying a charge for marginal energy losses,
generators incur a basic toll for transmission services, calcu-
lated as the difference between the network cost and the
revenue earned from the charge based on marginal losses.

Exact figures for each of these items are not available, but a
recent estimate is that the revenue from marginal losses cov-
ers much less than half (and perhaps as little as 15 percent)
of the total network cost (Rudnick 1994). Generators are
expected to recoup the basic toll from the contracts they
negotiate with large users, or "generator free" contracts.

However, in order to determine which assets to attribute to
any particular generator-free contract, the "zone of influ-
ence" of the generator must be defined. In theory, it is that
part of the primary transmission system where the generator's
input affects the (electrical) load flow; in practice, however,
the calculation may become a subject of contention.

The Chilean method of transmission pricing has the advan-
tage of providing locational incentives by charging genera-
tors for the marginal power and energy losses between nodes
on the system. The method should also provide the right
signal to add transmission capacity, at the time when the
present value of the additional sales that extra transmission
capacity permits is equal to the present value of the invest-
ment cost. In practice, however, the price signals to add
capacity are inadequate. Because the penalty factors that
determine node prices are based on peak transmission losses,
the revenues produced by these charges exceed the average
cost of line losses. However, this effect is dwarfed by the
"lumpiness" of transmission: that is, new capacity is added
typically in large blocks, and the revenues produced by pay-
ment for marginal losses are not sufficient to cover the aver-
age cost of the primary transmission system. The regulated
price therefore does not cover all the costs of the primary
transmission system. Even so, generators would be able to
recoup transmission costs if the regulated price were forced
up by its link with the "free client" price—which should
contain the full cost of transmission. In practice, this link is
not brought into operation, as the free-client price does not
diverge by more than 10 percent from the regulated price.
Moreover, it has proved difficult to reach agreement on the
basic toll element that generators charge free clients.

4. Adequacy of Investment

Until recently, it was axiomatic that a strong central govern-
ment role was needed in the electricity supply sector to
ensure that sufficient investment would take place to satisfy
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demand. Governments noted the strong relationship between GDP growth, on the one hand, and the growing demand for electricity, on the other. Such demand, it was argued, goes hand in hand with the expansion of industry, commerce, and agriculture and with higher living standards in households. At the same time, electricity supply is highly capital intensive and requires long-term investment planning, as construction of power stations can take up to a decade. Also, governments have been keenly aware—even apart from the economic consequences—of the political repercussions of a failure to supply power.

A problem with restructured power markets is that it is no longer obvious who will be responsible for investing in new generation, transmission, and distribution capacity to meet demand growth and who will have an obligation to supply electric power. Missing is the “comfort” that the traditional public monopoly model appears to provide—that the state-owned utility will carry out a least-cost analysis for generation investment to meet the projected demand growth and that transmission and distribution investments will then be made on the basis of the corresponding load-flow analysis.

On the other hand, experience throughout the world has shown that the resources necessary to make the needed expansion investments cannot be mobilized in practice without an appropriate enabling environment—in particular for the financial arrangements. As noted earlier, the World Bank has estimated that US$2 trillion will be needed to finance electric utility expansion through the first decade of the next century (Stern 1995). Developing countries have found it difficult or impossible to find resources on that scale. Countries such as India are facing significant capacity shortfalls that are attributable in no small measure to the poor financial viability of the state electricity boards, exacerbated by inadequate tariff levels.

Where electricity markets have been restructured, investment in new facilities must be ensured through financial incentives. The power pools examined provided two main incentives for investment in generation. First, three of the systems paid all selected generators the marginal cost (Norway and England and Wales) or the bid price (Chile), which creates a rent for intramarginal plants. The difference between actual marginal operating cost and the pool payment contributes to the reimbursement of capacity costs. A second type of payment was made in England and Wales and in Chile to provide a financial incentive to maintain reserve capacity, which would not otherwise be reimbursed through rents earned on energy generation. As discussed earlier, in Chile, this payment is based on the annualized investment and fixed operating costs of a 50 MW gas turbine. In England and Wales, the PPP includes a payment related to the LOLP and the cost of rationing. The latter was initially set at £2,000/MWh (since adjusted by the retail price index). The LOLP is recalculated every half-hour—consequently, the payments are volatile, and few investors depend on spot prices when making investments. Rather, investments tend to be made on the basis of long-term contracts, written by distribution companies with captive consumers. It is interesting to note that in both Chile and England and Wales, the capacity charges are administered and not market-based solutions. Hence, they may not provide correct incentives for capacity expansion.

The small size of the system in Northern Ireland made a power pool approach impractical. Instead, power was sold by the generators to the PPM on the basis of contracts linked to each generating unit. The price paid by the PPM comprised an availability fee and an energy payment related to indexed fuel costs. Generators obtained capacity payments from the availability fee. Finally, other case studies noted that distribution or supply bodies were required, through ownership or contract, to cover the requirements of their customers. In Scotland, the two vertically integrated utilities had to show this for their regulated customers. In NEPOOL, participating utilities were subject to fines if they did not cover their capacity requirements.

It is hard to assess the success of these incentive mechanisms on generation investment, as most of the systems in the case studies had excess capacity. However, Chile did provide evidence that high levels of new investment could be attracted in a growing system. In fact, private investors have shown willingness to construct twice as much capacity as CNE has specified in its indicative expansion plan.

The case of transmission investment has been much more problematic. Yet adequate investment in transmission is a prerequisite if IPPs are to be incorporated efficiently into a restructured power system. As we saw earlier, two types of financial incentive can be provided for investment in transmission. The first is to impose a congestion fee to reflect the cost of running generating plant out of merit order in response to transmission constraints. The second is a levy for capacity costs to provide against the probability that the trans-
mission system will be unable to deliver all energy where it is needed simultaneously.

The independent system operator responsible for the transmission network in Norway is largely owned by Statnett, a state company. Statnett is loosely regulated on a rate-of-return basis. However, Statnett relies overwhelmingly on the power fee to cover its costs. The power fee is determined residually, to secure the financial viability of Statnett, and accounted for some 69 percent of total revenues in 1993. Moreover, as Statnett was able to pass on its costs to grid users, the company had no direct financial incentive to reduce congestion costs or increase capacity in a least-cost fashion. Indeed, the variable part of Statnett’s revenue would be reduced if it made investments to ease transmission constraints and reduce transmission losses.

In Northern Ireland, a privatized company, Northern Ireland Electric (NIE), owned and charged for an integrated transmission and distribution (“wires”) business. NIE was explicitly intended to capture all the costs of providing, operating, and maintaining the transmission system through user charges. In fact, this was not achieved. Average losses and congestion costs were recovered through the bulk supply tariff, and the user charges effectively recovered only the network infrastructure costs. In particular, locational factors were only partly affected by charges to nonfranchise users and not at all by charges to other users. On the other hand, the regulated transmission and distribution revenues were adjusted by an amount, $T$, and reflect system losses, so that a financial incentive did exist to reduce such losses. Of course, whether or not the financial incentive is large enough to make the investment worthwhile depended crucially on the value of $T$ chosen by the regulator for any particular year.

In Scotland, transmission services are provided by two vertically integrated enterprises—Scottish Power (SP) and Scottish Hydro-Electric (SHE)—serving their respective franchise areas. Both companies are privately owned and treat transmission as separate profit centers. Transmission is not constrained within Scotland under normal operating conditions, and SP and SHE are required to allow third-party access. All system users must pay charges related to transmission assets, but no specific component is provided to cover future transmission investments. Capacity is limited on the interconnector, which serves only for export to England. It is owned by SP and has been allocated primarily between SP and SHE under a cost-sharing arrangement. Although SP is obliged to set a price for interconnector capacity if approached by a third party, this has not yet been tested.

As is the case of generation, the high level of transmission capacity that typified the case studies yielded little evidence on the degree to which unbundling had prejudiced investment in transmission. However, the difficulty of covering total costs through user-related transmission charges strongly suggested that bulk electricity pricing had been less successful in providing the right incentives for transmission investment. Furthermore, disagreements over the appropriate basic toll level in Chile (the main component of transmission revenue) led to inadequate investment in the transmission network.

Where governments have real concern that adequate levels of investment may not materialize under restructured markets, a central body can be designated to serve as an “investor of last resort.” Such a body would conduct indicative planning. Where private-sector investment is anticipated to be deficient, the central body would be able to provide and finance capacity. In Chile, the CNE prepares indicative expansion plans for 10 years and can recommend state financing of generation and transmission projects, if private financing is unavailable. In Northern Ireland, the PPM was proposed as the “contractor of last resort” to ensure that essential new capacity would be built when it would otherwise not be forthcoming.

5. Potential Problems with Regard to System Size and Transactions Costs

The last of the five basic questions arises from the fact that restructuring of power sectors is inevitably associated with transactions costs. These costs are not only “one time” costs of the restructuring process itself. They are also recurring costs, as the restructured system must be regulated and operated under transparent pricing rules to integrate the unbundled components. For example, the preceding discussion of the pricing arrangements for generation and transmission and the issue of contracts makes it clear that some of the benefits of unbundling may be offset by transactions costs. For this reason, as noted earlier, the attainment of a minimum system size may be critical for developing countries that are considering whether or not to implement vertical and horizontal unbundling of power enterprises. However, although unbundling is an important source of the gains from competition, the removal of government from key
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decisionmaking areas is typically a second fundamental goal of restructuring. That goal is not likely to be compromised in small power systems.

All of the power systems covered in the case studies are large by the standards of most developing countries. The smallest case was Northern Ireland's 2,400 MW system; next were Chile, at 5,000 MW, and Scotland, at nearly 12,000 MW. The other five exceeded 25,000 MW, with England and Wales being the largest, at 55,000 MW. In contrast, as noted earlier the recent World Bank study of small power systems (Bacon 1995) identified 107 developing countries with systems of less than 1,000 MW. Although 90 of the 107 were below 500 MW, several in the range between 500 MW and 1,000 MW were considering restructuring. These included Jamaica (500 MW), Bolivia (500 MW), Jordan (800 MW), and Costa Rica (900 MW).

Inevitably, the small size of the power system in Northern Ireland makes it a focus of attention, among the present case studies, for lessons of interest to developing countries. At the time of restructuring, the four power plants owned by NIE were sold to three private companies through a competitive tender. The remainder of NIE was privatized and separated into different businesses, among other things, for transmission and distribution, purchase of all generation, and retail supply. The PPM was established, as a substitute for a competitive pool, to handle the purchase of electricity from the three generating companies and its resale to suppliers under a bulk supply tariff. The PPM's purchases were all on the basis of contracts that guaranteed the salability of the existing four power plants. The PPM undertook centralized dispatch, with the merit order determined by the energy payments specified in the contracts. Such an approach may be a good way to minimize short-run operating costs in a small system. The PPM could also undertake indicative planning for long-term expansion in this type of model by requesting competitive tenders for required capacity additions. Eventually, as expansion takes place, it may be possible to move toward a competitive pool-based system. It should be recalled that growth rates are quite high in the power systems of many developing countries: annual growth at 7.2 percent, it should be recalled, leads to a doubling of system size in a decade.

Northern Ireland's experience is also of interest to countries making increasing use of IPPs. It shows how contracts with IPPs can be reconciled with least-cost dispatch, provided that energy charges are properly set and indexed. It also contains useful experience on the design of contracts and the regulation of the power purchaser. On the other hand, a major weakness has been the lack of competition in generation, perhaps reflecting the efforts of the government at the time to guarantee a market for the to-be-privatized generators and the intrusive role of the PPM.

The scope for applying the Chilean experience to developing countries has already been demonstrated in practice, despite some weaknesses in the model itself. Modified versions of the bulk pricing model introduced in Argentina and Peru, for example, have addressed the issues of transmission ownership. Whereas a single group in Chile controls nearly 60 percent of generation, owns the majority of transmission, and has the largest share in the country's main distributor, Argentina and Peru have separated transmission fully from generation and distribution.

Considerable caution must be exercised in drawing lessons from the Scottish model for developing countries. Notably, competition between existing utilities is extremely limited, scope for the entry of new generators is minimal, and over-capacity is substantial. Nonetheless, the Scottish model offers two valuable lessons for smaller systems considering reform. First, although SP and SHE were created as vertically integrated privatized electricity companies, they were obliged to prepare separate accounts and establish independent profit centers for their generation, transmission, and supply functions. This approach is likely to suit developing countries with very small systems, where unbundling is not practical, because it facilitates regulation and improves incentives to minimize costs. From the viewpoint of regulation, the price-capping approach used in Scotland has also helped to reduce transactions costs arising from the regulatory burden.

Second, the Scottish experience shows that “lumpiness” of station size and generation sets may be tackled through the writing of long-term contracts rather than through asset transfers. In Scotland, SP owned all the coal-fired stations, whereas SHE owned all the oil- and gas-fired plant and virtually all of the hydroelectric capacity. In 1990–91, maximum demand was 5,727 MW, and six stations were operating, each with capacity exceeding 1,100 MW. The largest coal station in fact accounted for 40 percent of maximum demand, and the one large gas-fired station was able to satisfy 23 percent of maximum demand. Yet instead of transferring assets between SP and SHE to balance the owner-
ship of assets, the solution adopted was to transfer capacity by (1) having SP contract part of its coal-fired generation to SHE for 15 years and (2) having SHE contract some of its hydroelectric capacity to SP for 49 years and a portion of its oil- and gas-fired plant to SP for 22 years. This approach may be borne in mind for other systems with “lumpy” capacities relative to maximum demand, provided that contracts are enforceable.

Although the England and Wales system is substantially larger than most developing countries, it has attracted a great deal of attention and has lessons of value even for the restructuring of smaller systems. The main problem in England and Wales has been ownership. The creation of an effective duopoly provided opportunities for strategic behavior that would be much less likely to exist if the generation sector comprised four or five players of similar size. However, the existence of at least four or five players is, at most, a necessary condition for competition, but not a sufficient one. The key is that the plant operated by these players must be substitutes in the merit order. This additional consideration introduces a further hurdle for small systems, especially those with mixed hydroelectric and thermal generation. In such systems, it would be difficult to ensure least-cost dispatch and competitive pricing, based on SRMC, even with several generators of similar size. However, it is worth bearing in mind that a competitive pool may be feasible even in small systems, if international interconnections are a possible factor.

Finally, investment in the England and Wales model is the outcome of free choice exercised by potential investors. Although this has the advantage of involving less state intervention, it also carries the risk that large-capital projects such as hydro schemes may not be funded, even if they are the least-cost means of expanding the system for a developing country with limited access to capital markets.
4. Conclusions

More and more governments in developing countries are implementing or seriously considering restructuring of their power sectors. These governments are striving to address the fundamental deficiencies of traditional public monopolies that allow little or no commercial freedom or competition. The experience of the case-study countries suggests that developing countries can structure unbundled sectors in a variety ways, especially with regard to the formulation of bulk pricing policies for generation and transmission.

Several of the case studies produced findings that are highly relevant to the reform of the vertically integrated utilities that are typical of developing countries. First, both Norway and Scotland have effectively enforced a separation of accounts between vertically integrated generation, transmission, distribution, and supply businesses. This is an important step toward greater transparency on costs. Second, by reallocating capacity through long-term contracts, Scotland was able to give companies the flexibility of access to a mix of generation technologies and unit sizes without undertaking outright asset transfers. Such contracts may be useful in power sectors with large unit sizes relative to their total capacity. Third, Norway illustrated that a change in the incentive system can be effected while retaining a high degree of public ownership. However, the finding may be difficult to replicate in countries where political interference in the power sector is deeply ingrained. Fourth, if the incentives to minimize costs are strong, trade between vertically integrated utilities should increase. Trade between England and Wales and Scotland provides a clear example of how a change in incentives led to more trade; and commercial inducements may be the best way to promote further international and inter-regional trade in Africa and India.

Northern Ireland provided an example for developing countries that are making use of IPPs. Long-term contracts with generators can be reconciled with least-cost dispatch if energy charges are correctly set and indexed. However, the bulk supply tariff for sales to supply businesses in Northern Ireland was poorly designed and gave inadequate signals on marginal costs at different periods.

The case studies were of more limited value in assessing the effectiveness of different bulk pricing arrangements on investment in restructured markets. They tended to be characterized by overcapacity in both generation and transmission. Nevertheless, Chile showed that fundamental reform can be successfully implemented in a developing country, and is consistent with the attraction of finance for new generation investments. In that sense, Chile demonstrated the potential for a pool based on costs rather than bids, a strategy suitable for a relatively small power sector. Chile's use of declared costs, subject to unannounced audits, appeared to incur lower transactions costs than NEPOOL's use of full cost audits. Transmission pricing, on the other hand, was less successful in Chile, as elsewhere, in providing appropriate incentives for investment in the transmission system.

Norway and England and Wales have introduced spot markets for energy and capacity. Several lessons emerge from their experience. First, modeling of the England and Wales Pool suggests that four to five generators need to compete at the margin if competition is to be successful. The duopoly that emerged distorted the market and caused the regulator to abandon the use of competition and instead to regulate prices through setting of a cap. Second, despite the development of sophisticated pools, energy and capacity are still mainly traded through the contracts market. In England and Wales, all capacity investments had been made against long-term contracts, although the situation was changing. Third, the potential inconsistency between long-term contracts and optimal dispatch may be offset, to some degree, by mechanisms for generator trading, as achieved by the Norwegian pool. However, the purely financial contracts traded in England and Wales, referenced against the pool price of electricity, resolved the problem of efficient pricing and dispatch, on the one hand, and long-term risk sharing, on the other.
Finally, experience suggests that restructuring is unlikely to reduce electricity prices across the board. In Norway, greater volatility of prices has also become a major concern. Nevertheless, the relevant comparison is not between prices before and after restructuring. For that it would be necessary to compare the situation after restructuring with some guess about what might have happened without restructuring—a task the studies did not attempt. Still, it must be acknowledged that restructuring may require generators to gain higher revenues to offset risk, although to some extent higher prices may have resulted from the poor design of some of the market structures. In any case, the low existing tariffs in many developing countries are a key cause of inadequate financial performance and are not sustainable.
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