Executive Summary

Developing countries need swelling quantities of electricity to power their emerging economies and serve growing populations. Escalating energy use will further strain the global climate by boosting carbon emissions, and it will degrade air quality, already ominously poor in many areas. Increased energy efficiency and emission controls alone cannot quell energy-linked pollution. Developing countries require clean energy sources, including renewable energy technologies powered by sunlight, wind, plant material, flowing water and the heat of the earth. Renewables can contribute to *bulk* power markets, in which large, centralized generating facilities deliver power to extensive transmission grids, and to *distributed* markets, which include small, grid-connected generating units installed close to where consumers use electricity, free-standing systems that supply isolated villages, or stand-alone units that power individual households.

As developing nations grow, many will abandon centrally planned, state-owned electric systems in favor of private investment, reduced debt, enhanced accountability and improved customer service. This paper *reviews the impact of power-sector reform on bulk and distributed markets for renewable energy* and offers recommendations for policy makers in developing countries seeking to improve environmental quality as they make their power sectors more efficient.

Types of Electricity Sector Reform

Developing nations have pursued three main types of reform. Under *commercialization*, governments maintain ownership of electric utilities, but remove subsidies and preferential fiscal policies, while requiring full recovery of capital, and of operations and maintenance costs. For many nations, commercialization precedes *privatization*, which can include the purchase of power from private power producers, the sale of existing facilities to private firms, and private financing of new facilities. Finally, nations may choose to *restructure* their electricity sectors by "unbundling" generation, transmission and distribution, and retailing into separate entities, with separate accounts and often with separate owners. Restructuring can include various levels of wholesale competition, retail competition and state regulation.

How will Reform Affect Distributed Markets for Renewables?

Commercialization should help renewables in the distributed market. Utilities required to recover the cost of serving isolated rural areas will find small renewable energy systems cheaper than grid extension or expansion—even apart from their environmental advantages. Distributed renewables reduce demand for grid electricity, so that utilities can channel power to cities, where clustered customers use more electricity per unit of capital outlay.

Privatization may impair markets for distributed renewables. Private energy suppliers face higher interest rates than government entities, and will value conventional energy options with a more rapid rate of return. Private companies may also care less about "social objectives" such as environmental protection.

Restructuring will have mixed impacts on renewables. Most troubling, no single player in an unbundled system may be able to benefit from avoiding new transmission construction by installing distributed resources. On the other hand, restructuring may allow customers to choose power suppliers. If prices accurately itemize the costs of generation, transmission and distribution, customers may have an incentive to install distributed energy systems generally; if prices reflect the cost of damage to the environment from using conventional generating technologies, customers may prefer electricity from renewables sources in particular.

How Will Reform Affect Bulk Power Markets for Renewables?

Commercialization alone will have little effect on bulk power markets for renewables, although it may improve utilities' ability to adopt new technologies.

Privatization, by contrast, will not benefit renewables. First, private power producers will prefer energy options with low capital costs and dependable operation. Second, since private producers locked into power-purchase agreements often must recover investment over the contract period, renewables with a comparatively high capital cost may find it difficult to attract private debt financing. Third, preparing a bid for site-specific renewable energy projects may cost more.

Restructuring that includes "spot" markets for wholesale power (i.e., markets for bulk power to be delivered immediately) will be particularly unfriendly to renewables such as wind and solar that are only available intermittently, since spot markets value generators that can assure power during peak periods. Owners of transmission facilities may also charge intermittent renewable energy projects comparatively more for access to power lines. Retail competition without inclusion of environmental costs in energy prices may prove equally troublesome for renewables, as customers eschew more expensive renewable energy in favor of the cheapest power available.

Conclusions

Low base case: Historically, few utilities in developing countries have promoted renewables. State-owned monopoly utilities seem unlikely to do so in the future. At best, reform can allow the power sector to weigh new options for expansion, especially through the distributed model. At worst, reform can strengthen existing biases toward conventional resources.

Indicators of success: Electricity systems will more likely adopt renewables where governments eliminate fuel and tariff subsidies; where utilities account for generation separately from transmission and distribution, and; where utilities extend rural service in the cheapest manner possible. Renewables will gain most from reform where many people currently lack electricity.

Privatization: While privatization can promote renewables by introducing new capital and disrupting monopolies, higher discount rates and short time horizons may favor non-renewables.

Competition: Wholesale and retail competition are likely to deter investments in renewables in the absence of appropriate regulatory incentives.

Unbundling and distributed renewables: Renewables will play a larger role in the distributed system rather than the bulk system. However, successful deployment of distributed renewables in an unbundled system may require that at least one player can capture system benefits.

Recommendations

- To avoid "locking in" polluting technology, developing country governments should evaluate proposed reforms with respect to the incentives they provide for technology choices.

- Bilateral and multilateral aid should help developing nations design indigenous, environmentally sustainable models for power sector structure, operation, and regulation.

- As developing countries reform their power sectors, they should enact laws and regulations that specify and strengthen the responsibilities of privatized distribution companies for rural electrification. They should also clarify sources of funding for rural electrification.

- Regulation of retail electricity suppliers should create economic incentives that promote full consideration of renewable technologies on both the supply and demand side. Power sector reforms should ensure that distributed options can compete to provide electricity services.

- Power purchase agreements need to be crafted in ways that avoid biases against participation by renewables in bulk power markets.

- Where transmission services become common carriers, all types of generation should have equal access to transmission capacity.

- Wholesale power markets should be required to consider the environmental characteristics of competing generators.

The current period of power sector reform in developing countries will last at least a decade. It will open huge markets to renewables. In some of these, renewables will have a competitive advantage. But the moment of opportunity will eventually pass: if developing nations adopt rules that lock in conventional technologies, they will lose a unique occasion to develop a clean, economically efficient power sector.

Electricity Sector Reform in Developing Countries:

Implications for Renewable Energy

By Dr. Keith Kozloff 1

Electricity power reform can stimulate renewable energy use in developing countries. But the moment of opportunity will soon pass. If developing nations adopt rules that lock in conventional technologies, they will lose a unique occasion to develop a clean, economically efficient power sector that serves more people at an affordable price.

This paper explores how different reforms either promote or inhibit the growth of renewables in developing countries. The first section considers the advantages of renewable energy for these nations and its deployment thus far. Part II provides a taxonomy of current reforms. Because the effects of reforms on renewable bulk power and renewable distributed applications differ, subsequent sections treat these two markets separately. Part V summarizes major conclusions and offers recommendations for using the reform process to promote greater use of renewables.

PART I. Renewable Energy Markets in Developing Countries

Renewable energy resources -- sunlight, wind, running water, biomass, and geothermal heat -- are widely distributed throughout the developing world. They are starting to be exploited through a range of technologies that convert natural energy flows to electricity. Their declining costs and commercial maturation mean that technologies that rely on renewable resources can now be used in a variety of situations.

Advantages of Renewable Energy

Renewable resources are indigenous, do not require fuel purchases, and can be used locally for power generation. So they are particularly advantageous for off-grid applications. In fact, the future of renewables in the developing world may be determined by the extent to which they are used to serve rural populations. At present, roughly 2 billion people in the world do not receive electricity. Other households are nominally served, but service is so unreliable that they choose to invest in their own sources of power. In the absence of reliable grid power, residents become "self-generators" -- they use diesel generators, kerosene lamps, lead acid batteries charged by diesel generators, candles, and diesel pumps. Many of these sources emit pollutants with adverse environmental and health effects.

In addition to their other advantages, renewable resources could play a significant role in limiting the environmental effects of energy use. Many developing countries, including China and India, are burning increasing quantities of coal to generate power -- with both local health and global climate effects. Improving the environmental performance of the power sector requires changing the generation mix, installing pollution controls, and limiting power demand by improving energy efficiency.

As a result of rapidly growing electricity demand, carbon emissions in the developing world are projected to outpace those in countries that belong to the Organisation for Economic Co-operation and Development (OECD).2 (See Figure 1 on Page 2). According to the World Bank, improving the efficiency of electricity generation, distribution, and use will not be enough to keep greenhouse gas (GHG) emissions from increasing over the next 25 years; doing so will require moving away from dependence on fossil fuels.3 Switching to low- and no-carbon technologies, including renewables, for new electricity generation is the only way for developing countries to cap both their GHG emissions and local pollutants.

At the same time that interest in renewables is growing, developing countries are reforming the way electricity services are provided. (See Box 1.) On the one hand, reforms could offer renewables the opportunity to compete fully and fairly for market share in some countries for the first time. On the other hand, they could further entrench energy technologies that pose local and global environmental threats.

The stakes regarding the impact of reforms on renewables are high. Total projected growth in electricity consumption between 1993 and 2015 in non-OECD countries exceeds that of industrial countries. (See Figure 2.) Asia will contribute the largest increase. (See Figure 3 on Page 5.) Due to high electricity demand growth rates -- in some countries, in the double digits -- new investments in the power sector made in developing countries over the next 20 years will be as large as cumulative investments to date. Countries that have initiated reforms already constitute 78% of generating capacity in non-OECD countries.

Renewable Energy Deployment to Date

Until recently, the deployment of renewable energy technologies in developing countries occurred primarily through direct government investments or international donor programs in which renewables did not compete in open markets. Where renewable pilot projects have been implemented by publicly owned and managed utilities, the decision was often made in order to meet planning, political, or technological objectives.

Today, however, renewables are increasingly deployed commercially in competitive markets. And public support is more oriented toward creating a market environment in which renewables can compete fairly for market share.

Renewable energy technologies compete with nonrenewable technologies to penetrate markets for "bulk" (large-scale) and "distribution" power generation. (The latter refers to small-scale generation to support a grid, to power village mini-grids, or to serve individual households.) Consumers can also use renewables instead of electricity to meet demand-side needs (such as daylighting, water heating, and space conditioning). (See Table 1 on Page 6.)

The successful penetration of renewable energy into bulk markets depends on several factors -- the quality of locally available resources, technological developments affecting the relative cost competitiveness of renewable versus nonrenewable options, and the structure and operation of such markets. Large hydropower, geothermal, and biomass cogeneration (combined heat and power) have already made significant contributions to meeting bulk power needs in several developing countries. For example, India has become a leading wind power producer.

Renewables have also made inroads in distributed power markets, primarily for rural electrification. Local dealers are marketing solar home systems and related services, for instance, in the Dominican Republic, Kenya, India, Sri Lanka, and Zimbabwe. A World Bank loan for solar home systems in Indonesia is based on a competitive market of individual small entrepreneurs.4 In such markets, renewables are competing with energy sources based on fossil fuels that are transported long distances or with the generation, transmission, and distribution costs of grid extension.

The future market penetration of renewables in developing countries depends on which model these countries emphasize for power sector expansion. The central station model (in which power lines emanate from a large generating station) has dominated in the United States and other industrial countries. However, more recently an alternative, pro-renewables model has been evolving. This "distributed utility" model places less emphasis on central generation and more on modular generation units that are strategically located close to where power is actually needed -- which is especially desirable in countries with large unconnected rural populations. (See Box 2.) Because OECD countries export both their technologies and their infrastructure models, it is too soon to say whether the distributed model will take hold in developing countries.

PART II. Major Types of Power Sector Reform

Typically, governments implement a package of reforms in the power sector. By and large, however, the decisions regarding specific reforms can be separated and occur at different points in time. By understanding the various implications for technology choice, policymakers in developing countries can make informed decisions about what types of reforms to adopt and how to implement them.

Characteristics of "Pre-Reform" Power Sectors

In most developing countries, the power sector has been publicly owned, viewed as a public service, and often dominated by a central planning philosophy. Universal electrification is frequently a national policy objective, as is the provision of electricity services to low-income customers at subsidized rates. In some countries, both upstream sectors (fuel extraction and transport) and downstream sectors (major industries) are also under government control and ownership. Rural electrification has generally been the responsibility of the government utility, although rural electric co-operatives have also been active, particularly in Latin America. (See Box 3.)

Because of poor cost recovery, managerial inefficiency, and inability to attract sufficient capital, the gaps between electricity supply and demand are widening in many developing countries. Self-generation (using diesel generators, for example, or kerosene lamps) constitutes an average of 13% of total power generation in the 75 developing countries with available data, and represents over 25% in 12 countries, mainly in Africa.5

Using distributed generation to reduce distribution system investments (such as substations) has been extremely rare in developing countries. Since evaluating distributed applications requires detailed time- and location-specific cost data, most developing-country utilities are not able to complete the needed investment analyses.

In the pre-reform world, renewable energy technologies, such as solar water heaters, have played a modest role in reducing power demand. Utilities have invested in demand-side management (DSM) in several countries, including Brazil, Indonesia, and Thailand. Elsewhere, government agencies have sponsored such programs. Under state ownership and management of utilities, DSM activities will continue where they have been started, but often at levels constrained by weak end-user price signals and by utility revenue shortfalls that are covered by transfers from the national treasury.

Although these characteristics tend to distinguish pre-reform utilities in developing countries from their OECD counterparts, the power sectors in these countries are by no means homogeneous. For example, fossil or hydro capacity may dominate the current generation mix. Some power sectors are too small to gain much from competition; others would benefit from it. Electricity demand per capita and per unit of national income also varies widely.

Changes in Power Sector Ownership and Operation

To address the critical challenges facing their power sectors, many developing countries are now reforming the way that electricity services are provided. They are opening power generation to private investment, further privatizing transmission and distribution, and even restructuring the sector to introduce competition and independent regulation. Governments are reforming the electricity sector to stimulate private investment and thus free up large amounts of public capital for other uses, to promote managerial accountability and better customer service, and to reduce government deficits and international debt.6

Developing countries tend to emulate successful electricity sector models pioneered in a single country. In the 1940s and 1950s, developing countries generally modeled their power sectors on their main economic partners among industrial countries (France, the United Kingdom, or the United States). In the 1980s and 1990s, reforms adopted by Chile and Argentina have been sweeping Latin America (Guatemala, Bolivia, Colombia, and Peru). Also in the 1990s, privately developed power plants have been spreading across Asia, Central America, and the Caribbean, although with less competition than in the United States. Francophone Africa has been experimenting with privatizing utility management, based on French models.[7]

Commercialization involves introducing commercial objectives into the management and operation of a state-owned enterprise. Subsidies are often removed, including state guarantees for borrowing, and the enterprises become subject to the same tax laws, prices, and accounting rules as other companies in the private sector. To make the company more attractive to private investors, the state-owned enterprise may assume past debts, reduce staff, and provide new operating capital. As part of commercialization, cost accounting is separated for generation, transmission, and distribution services.

An important part of broader managerial reforms is recovering the actual costs of electricity service. (This is often required as a condition for receiving concessionary loans from multilateral development banks.) Cost recovery is improved by adjusting rates to better reflect the costs of serving individual customer classes, by upgrading revenue collection with more effective metering and billing practices, and by reducing energy theft. A few countries have begun to charge customers different rates according to the time of day when power is demanded.

Most countries view commercialization as an intermediate step toward privatization and other reforms, although some have commercialized their power sectors but may never privatize them. Countries in this category include Cote d'Ivoire, Ghana, Malaysia, Senegal, Singapore, and Thailand.

Privatization transfers existing power sector assets to private ownership and allows private development of some or all new power sector infrastructure. While privatization of public enterprises in various economic sectors has been a widespread phenomenon among both OECD and non-OECD countries over the past decade, the electric power sector is typically one of the last enterprises to be affected because its functions are considered by politicians to be vital to the state.

The traditional method of assigning new projects for private-sector development is for the utility to draw up expansion plans and assign specific projects for private financing. Another approach is to specify capacity requirements and let the private sector identify least-cost sources. Several models exist for private participation in power generation -- for example, Build-Own-Operate (BOO), Build-Own-Operate-Transfer (BOOT), Build-Maintain-Transfer (BMT), and Build-Lease-Transfer (BLT). Developing or emerging economies that allow private power include Argentina, Bolivia, Brazil, Chile, China, Colombia, Costa Rica, Cote d'Ivoire, the Dominican Republic, Guatemala, Guinea-Bissau, Honduras, India, Indonesia, Jamaica, Kenya, Laos, Malaysia, Mauritius, Mexico, Morocco, Nepal, Pakistan, Panama, Peru, Philippines, Poland, Russia, South Africa, Tanzania, Thailand, Turkey, Ukraine, and Viet Nam.

Power purchase agreements (PPAs) are a key component of schemes in which private developers retain ownership of the generation facility (BOO). A PPA's single most important provision is the price at which the utility agrees to buy power from the developer.[8]

The range of ownership reforms is bounded by full private responsibility for operation of existing assets and new investment, through either long-term concession or change in ownership. Major sales of power sector assets have occurred in Latin America, and partial sales have occurred in Indonesia, the Philippines, and India.

Privatization is commonly associated with politically independent regulation of those power sector components that remain in monopoly control. Full privatization means that the private-sector operator takes its revenue from final customers. Regulation is supposed to ensure that the tariffs charged allow the utility a fair return on its investment.

Although tariffs may be reformed as part of commercialization, the utility's incentives to recover costs become even stronger when a private owner takes over. Allocating ownership and management to the private sector and giving regulatory functions to a public agency that is at least partially independent of political pressure increases the prospects for basing tariffs on actual costs of service. Tariff subsidies are common in developing countries, but reform does not necessarily mean price increases. Depending on customer class, cost-based tariffs could go up or down.

Restructuring alters the existing organization of the electric industry. In the extreme, vertically integrated utilities (providing generation, transmission, distribution, and retailing services) are unbundled into legally and functionally distinct companies. Chile, England, and Wales pioneered unbundling models in the 1980s. Since then, developing countries or states in which generation, transmission, and distribution assets have been or are being separated include Argentina, Bolivia, El Salvador, the Indian state of Orissa, Nicaragua, Pakistan, and the Philippines. Unbundling is also popular in Eastern Europe.

Variations among countries exist within the overall framework of unbundling. In some, the distribution services have also been divided according to geographic franchises. And in some countries, independent generators sell to a single power procurement business. Such single-buyer models are appropriate for smaller systems, where the potential gains from competition are too small to offset transactions costs.9 Also, some countries have separated electricity distribution from retail services, while others have kept them within the same company.

While the "wires" portion of the electricity sector (transmission and distribution services) is still considered a natural monopoly, competition may be introduced into the system for selling power to the grid (wholesale competition) and providing electricity to end-use customers (retail competition). Wholesale competition may take the form of independent power producers (IPPs) bidding for long-term contracts with power purchasers. Although many styles of bidding exist, commonly the utility solicits bids from project sponsors and awards the lowest-cost supplier, regardless of the type of generation. The selection emphasizes lowest fixed costs, and the winning bidder receives payment sufficient to cover fixed investments and operating costs. Purchasers tend to award contracts on the basis of capacity and energy costs in the first few years of a project's 30-year life span.

As an alternative to awarding long-term contracts, some countries (such as Chile and Argentina) are creating spot or short-term markets for wholesale power. Under this model, multiple generators bid to be dispatched by an "independent system operator" (ISO). The ISO purchaser relies on competition to ensure that bids are kept low. (If individual generators constitute too large a share of the market, they can manipulate output or availability to increase profits.) Generation projects that depend on spot markets for most of their revenues are called "merchant plants." (See Box 4.)

In addition to wholesale competition, a few places (California, England, Norway, and Wales) are experimenting with retail competition for some or all customer classes. Retail competition is most feasible in areas with significant numbers of industrial and large commercial customers, who are typically more attractive targets for competing firms than residential customers. Consequently, governments can open competition for large customers and then phase in smaller customers.

Retail competition can be introduced through different methods. In one, multiple power generators have direct access to the transmission and distribution networks (for a charge), allowing them to compete to supply final customers regardless of their location or who owns the wires. In another, independent retail service providers (which do not own any generation facilities) buy power from generators, contract for use of transmission and distribution facilities, and sell the power to final customers. Where distribution and retail functions remain within the same entity, the service provider buys from wholesale power producers and contracts for transmission access.

PART III. How Reforms Affect Deployment of Renewables in Distributed Power Markets

Distributed applications constitute the largest near-term market for several renewable energy technologies. The reforms under way in numerous developing countries affect the extent to which the distributed resource model, particularly regarding renewables, is used when expanding the sector's infrastructure.

Commercialization

Commercialization generally favors renewables, at least compared with a situation in which there is no reform. When utilities commercialize, they are forced to attend to cost recovery. This means that they may reduce subsidies to rural customers, sending more accurate price signals. Better management is likely to mean better information on cost of service and more attention to the environmental implications of investment choices. A commercialized utility is more likely to identify the least costly manner of extending service to rural areas.

Commercializing a public utility may improve its incentives to implement DSM and grid support applications of renewables. To the extent that a commercialized utility has an incentive to reduce sales to where the cost of supplying the next kilowatt-hour is greater than the revenue received, it should be willing to pay up to the difference (the cost subsidy) not to have to supply that kilowatt-hour. For example, a utility could invest in photovoltaic-powered water pumps in lieu of extending the grid to farmers who would receive heavily subsidized power. Grid power could be reserved for urban customers who pay the full cost of service. In a country with unmet demand for power, this policy would not necessarily result in "lost revenues."

Privatization

Privatization has mixed effects on distributed applications of renewables. It strengthens the managerial improvements and cost recovery changes begun under commercialization. At the same time, when ownership is transferred to the private sector, the cost of capital used in making investment decisions is likely to increase. As a result, demand-side investments yield a lower rate of return than they would under public ownership because the investment is made right away while the benefits, accruing over a period of years, are discounted.10 For this reason, fewer DSM measures are attractive to a private utility than to a public one.

Second, privatization is likely to dampen interest in serving rural markets, where renewables have a comparative advantage. In some countries, the government regulator grants the new private owner a long-term concession for the right to distribute electricity to a defined geographic area that includes both urban and rural customers. Unless required by regulation, the privatized utility is reluctant to extend service where doing so does not meet its profitability criteria. The ability to cross-subsidize rural customers is limited. Shareholders may require higher rates of return to justify investments in rural markets, which are viewed as being relatively risky. In addition, the utility may or may not have the authority, interest, or expertise to pursue other means of providing electricity services to rural areas. To address these issues, the Government of Argentina is implementing a "rural concessions program" (see Box 5 on Page 11), and Brazil is considering a similar initiative.

Third, public utilities have often pursued other social objectives in addition to universal electrification that may have involved deployment of renewables, such as economic development and technology commercialization. When a utility is privatized, its pursuit of social objectives in response to national policy or political mandates wanes. The responsibility for implementing such objectives transfers to regulators, who seek to balance these goals with the utility's economic well-being.

Fourth, the form of regulation that accompanies privatized retail services affects the incentives for end-use customers to invest in on-site renewables. Under some tariff structures, customers could see fully itemized rates based on area- and time-specific energy, transmission system capacity, and distribution capacity costs. Depending on the previous structure, such rates could improve ratepayers' economic incentives for managing their demand and reducing consumption. Key factors include how costly it is to install meters that charge according to time-of-use, whether location-specific costs can be differentiated, whether hook-up fees reflect the customer's load, and whether meters are allowed to "run backwards" to credit on-site generation. Regulators might also adopt policies to improve incentives for electricity suppliers to make demand-side investments that reduce system-wide costs.11

Restructuring

The implications of separating a utility into independent firms that individually provide generation, transmission, distribution, and retail services for distributed applications of renewables depend on how the allocation of costs changes. Before unbundling, a utility can calculate the value of distributed generation by adding up the costs associated with central station generation, transmission, and distribution that are avoided. After unbundling, the entity most likely to be considering distributed generation investments (the distribution company) may not be able to fully identify, value, and capture upstream generation and transmission costs that would be avoided by such investments. At best, the way that upstream costs are passed through in an unbundled power sector would not diminish the cost-effectiveness of distributed generation to a distribution company. At worst, unbundling causes the set of attractive distributed generation investments to shrink. Still, distribution companies might find some such investments to be cost-effective in locations where:

* the marginal costs of service are particularly high due to network constraints;
* service must be extended to customers with low loads who are far from the grid; and
* sharp local peak demand results in inefficient use of distribution assets.

Competition

Competition affects the attractiveness of investments in distributed renewables in several ways. First, a thriving competitive wholesale market should drive down generation expenses, thus reducing the costs that can be avoided by distributed renewable installations. Spot markets, for example, often operate on the basis of competing generators' short-term operating costs. Compared with long-term power purchase agreements based on full costs incurred over a project's life, spot generation markets weaken the incentive to invest in distributed renewables whose costs must be recovered over a period of several years.

Second, competition among electricity suppliers for retail customers creates an incentive to minimize capital investments that would put upward pressure on rates in the near term, even if they would hold down rates in the long term. Over time, the focus of retail competition may shift from low cost to customer value. If so, retail suppliers may offer packages incorporating distributed renewables, including demand-side applications, to differentiate themselves from competitors.

Third, competition at the wholesale and retail levels is likely to make retail rates more variable and less predictable. End-users investing in demand-reducing measures face the risk that the dollar savings over the life of the measure may be less than expected. This risk is exacerbated when future electricity costs are less certain.

PART IV. How Reforms Affect Deployment of Renewables in Bulk Power Markets

To date, few publicly owned and managed utilities have constructed bulk renewable generation facilities other than large hydro. They have not had strong capabilities for adopting emerging technologies and have tended to use more familiar and conventional generation equipment.

Commercialization

By itself, commercializing public utilities has little effect on renewables in bulk power markets. Still, the ability to adopt new technologies may be improved. Renewables may be considered more seriously to the extent that improved management, cost accounting, and cost recovery increase the utility's interest in choosing the least-cost approach to expanding service on a life-cycle basis.

Privatization

Similarly, privatization is unlikely by itself to increase the market share of renewables. Technology preferences for investments in new generation result partly from differences in project financing available to public utilities, private utilities, and independent power developers. When new generation is privatized and unbundled, independent power producers must generally finance projects on the basis of the expected returns from the specific project and the need to recover investment over the loan repayment period. In contrast, public utilities, backed by sovereign guarantees, often face lower costs of capital. Because even well-capitalized private developers do not have the credit capacity to underwrite the debt on a portfolio of projects whose total capital costs may be hundreds of millions of dollars, obtaining third-party debt is essential. Consequently, independent power developers face a higher cost of capital and a shorter repayment period than vertically integrated utilities. They must recover their investment over the period of their loan repayment. All things being equal, the cost of energy from a capital-intensive renewable project to either a private utility or an independent power producer is higher than to a public utility. (See, for example, Box 6.)

Because of these financial considerations, private developers prefer generation options that have relatively low capital costs per megawatt, a short construction time in order to yield revenue quickly, high efficiency, and the ability to be operated most of the time. Based on recent trends, private developers appear to favor natural gas generation (sometimes even where liquefied natural gas must be imported) due to its cost structure and short construction time. Generation options that are not favored are coal, nuclear, hydro, and other renewables. In developing countries where public power systems have relied heavily on hydro, for example, the transition to private financing has resulted in increased use of thermal generation at the expense of hydro. Hydropower is unattractive to independent power developers because of its capital intensity and relatively long lead time (for large projects).12 In Latin America, natural gas has often displaced hydro for new generation. In Asian countries where natural gas is not available for power generation, coal often displaces hydro for new capacity.

Power purchase agreements can also affect financing for renewables, depending on the extent to which provisions in these agreements are geared to the characteristics of renewable generation options. Since most independent power projects have been thermal to date, the terms of standard PPAs are often geared to such projects. Payment schedules and other terms in PPAs may create incentives for independent power producers to choose relatively low capital-cost-per-megawatt generation technologies over options with comparable life-cycle costs but higher capital costs. PPAs often guarantee fixed price payments to developers over a limited period of time. Adequate payment schedules are particularly critical for capital-intensive power generation options, a characteristic of geothermal, wind, hydro, solar, and thermal options. Independent power developers must attract private debt financing on the strength of PPAs. They must often recover their capital investments over the fixed price contract period (generally less than the facility's life span). This is harder to do for developers of capital-intensive generation options, putting them at a competitive disadvantage relative to developers of fuel-cost-intensive options.

Renewables face other barriers in obtaining long-term power contracts. Transaction costs incurred to participate in the bidding process may favor certain technologies. Per megawatt, the costs of preparing a bid for a thermal project are less than for a renewable project. They can be readily determined and are not particularly site-specific, allowing bids to be prepared more quickly and cheaply. Developers of small-scale renewable power sources may find the transaction costs of negotiating PPAs prohibitive.

The treatment and allocation of risks in PPAs can also be biased toward some technologies. PPAs ideally specify which party will assume different risks. Otherwise, equity owners of the project are typically assumed to bear them. For example, PPAs may include fuel cost indexing provisions that protect developers of thermal projects against the risk of future fuel price volatility.

In some countries, many of these issues have been addressed through the development of standardized power purchase agreements that include provisions on how much the utility will pay for the power over a specified period of time. Where private power projects that use renewable resources have fared relatively well (such as India, Indonesia, and the Philippines), the terms of power purchases and other policies have been explicitly geared to the characteristics that distinguish renewables from conventional power sources. (See, for example, Box 7.)

Restructuring

The conditions and rates under which independent power producers can gain access to the transmission system and use it to "wheel" power for sale directly to electricity users affect the independent power producer's choice of technologies in grid-connected applications. Transmission access has the potential to stimulate development of new renewable power generation. Because renewable resources are location-specific, developers of renewable power generation depend on access to transmission lines to sell power to the grid. Moreover, transmission access gives renewable power developers the ability to sell power to locations where, and at times when, it is more highly valued than by the local utility.

Despite legal and physical access to transmission lines, however, renewable developers may not have equal access to transmission capacity because of unfavorable contract terms. Developers of intermittent generation may be charged more per kilowatt-hour to transmit power than their dispatchable competitors. Transmission access charges may be based on a generator's maximum rated capacity or what it actually generates during peak periods. Moreover, the site-specific nature of renewables may be a drawback under some transmission pricing schemes. Rates may be based on distance or contract paths regardless of actual transmission costs or the flow of electrons. To facilitate wind power development, several states in India charge 2% of the power transmitted for wind generators to gain transmission access. (Unfortunately, transmission system bottlenecks reduce the effectiveness of this policy in some states.)

Competition

Wholesale competition is not likely to favor renewables in bulk power markets. Compared with long-term bilateral power purchase agreements, short-term or spot markets make it more difficult to finance and develop renewable generation options. For one thing, renewable projects bidding into spot markets are harder to finance than generation projects with low capital costs. Lenders are reluctant to provide debt capital for renewable energy merchant plant projects, especially in countries where spot markets have yet to establish a track record. Since lenders require that power projects demonstrate steady, predictable cash flows to meet debt service requirements over several years, the revenue risk created by unpredictable spot markets effectively precludes financing.

Spot markets are particularly unfriendly to the development of "intermittent" renewable resources that generate power when the sun shines and the wind blows. Their prices may be high for a limited number of hours in a year and not necessarily when these intermittent renewable resources are available. The inability to generate power on demand is more of a drawback in spot markets, which place a high premium on generators that can assure power availability during peak periods. Because these resources cannot be dispatched on demand, the rules governing dispatch and payment in competitive wholesale markets are particularly important in determining their value. In contrast, developers of thermal plants can secure financing because they have greater control over when they sell to the spot market and because their lower debt load gives them less exposure to a prolonged slump in market prices.13

Retail competition is also likely to affect the ability of renewables to compete in bulk power markets in developing countries. The incentive to retain and attract customers that is created by retail competition makes electricity suppliers seek opportunities to minimize rates and to differentiate themselves from competitors. In the United States and parts of Europe, some retail suppliers are trying to differentiate themselves by marketing "green" (environmentally friendly) electricity generation. This market niche is, however, likely to be much smaller in developing countries because environmental consciousness is generally lower and electricity costs tend to loom larger in household or business budgets.

V. Conclusions and Recommendations

Making generalizations about how power sector reform will affect market prospects for renewables is complicated by the range of reforms, the characteristics of different power markets that renewables might enter, and the variation among countries' pre-reform conditions. Table 2 summarizes the key relationships between reforms and the different markets for renewables discussed in this paper.

Conclusions

Despite the difficulty in making generalizations, several conclusions can be drawn:

* The implications of power sector reform for renewables depend on assumptions about the pre-reform "base case." Other than large-scale hydropower, there are few cases where renewables have made major in-roads into the bulk or distributed power markets of developing countries. With some exceptions, this experience is unlikely to change under a continuation of state-owned monopoly utilities.

* Some power sector reforms enacted or contemplated in developing countries will improve market opportunities for renewable energy equipment suppliers and developers; others will not. At best, a better managed power sector will be in a position to weigh carefully new options for system expansion, especially using the distributed model. At worst, reforms that strengthen incentives to choose nonrenewable power sources represent not so much a retrenchment as a missed opportunity.

* In general, prospects for renewables penetrating distributed markets are improved when fuel and tariff subsidies are eliminated, when accounting for transmission and distribution costs is separated, and when the distribution provider chooses modes of service extension on the basis of the lowest system cost.

* Prospects for renewables in bulk power markets are less clear in the transition from public to private investment, since privatization's advantages (influx of new capital and breaking the state monopoly on power generation) are likely to be offset by its disadvantages (high discount rates and short time horizons leading to preference for thermal generation over more capital-intensive options).

* The introduction of wholesale and retail competition is likely to hurt the prospects of renewables in the absence of countervailing policy interventions. Without an explicit GHG policy in developing countries, such as carbon values imposed on fossil fuels, bulk renewable capacity may increase in absolute terms but is unlikely to increase market share dramatically. Investments in demand-side renewables are not likely to be made without appropriate regulatory incentives. This finding is particularly important for power sectors that are small or have other characteristics that make the economic benefits of introducing competition relatively modest.

* With respect to restructuring, the deployment of distributed resources will be determined by the ability of at least one player in an unbundled sector to capture system benefits.

* Renewables are likely to play a larger role if power sector reforms encourage consideration of the distributed rather than a central station model. In the near term, renewables will be most successful in competing for off-grid customers and other distributed applications where system costs for generation, transmission, and distribution are high.

* Power sector reforms have the greatest potential to improve the status quo in countries with large unelectrified populations. A privatized distribution company given exclusive access to an off-grid area can balance the returns of grid-connected and off-grid customers. It also can absorb market entry costs, achieve economies of scale in equipment and in operations and maintenance costs, exploit its existing network of local agents, and use its large cash flow to finance systems and absorb seasonal variations in customers' ability to pay.

Recommendations

The current period of power sector reform in developing countries will last for at least a decade. It offers both an opportunity and a danger for renewables. The opportunity is related to the sheer size of the various markets in which renewables can participate, and in some of which they enjoy a comparative advantage. The danger is that the rules governing reformed power sectors and markets will lock in conventional technologies. To realize the opportunity afforded by reform, stakeholders should consider the following recommendations.

Developing-country governments should evaluate the implications of specific reforms being considered with respect to incentives for technology choices.

To avoid potentially adverse environmental effects of introducing competition to the power sector, reformers should reassess specific reform packages being considered to ensure that modest economic gains are not made at the expense of locking in nonrenewable power generation. Mitigating measures should be concurrently implemented -- such as initiating funding for sustainable energy options, drafting wholesale market rules that not biased against renewables, and advocating regulatory policies that give retail service providers incentives to offer demand-side services.

Bilateral and multilateral assistance organizations should help developing-country governments design indigenous models for power sector structure, operation, and regulation that are environmentally sustainable.

Due to the lack of indigenous alternatives, developing countries tend to adopt both electricity technologies and policy frameworks from industrial countries. Successful institutional models for the power sector that have been pioneered in one country have been widely observed among developing nations. International donors should provide technical assistance in developing indigenous structural models and institutional mechanisms for sustainable energy development that are geared to the power sector characteristics of specific client countries. For example, many developing countries might be better suited to a distributed model of power sector expansion. The distributed utility model might call for a completely different sectoral structure than reform trends in OECD countries would suggest.

Developing-country governments should enact laws and regulations that clarify and strengthen the responsibilities of privatized distribution service providers for rural electrification.

Key decisions in the privatization process include drafting the terms of sale of a utility, establishing criteria for awarding bids, creating the distribution concession contract, and determining the subsequent regulation of the concessionaire. The whole sequence of decisions has a potentially significant effect on the incentives for rural electrification based on renewable energy.

Because government retains greater leverage over rural electrification prior to the majority ownership sale of the utility, it should specify at least some fundamental rural electrification requirements in any privatization bidding document it issues. Then all bidders could assess the associated costs and risks and could factor them into the dollar value of their bids. Beyond minimum requirements, bid evaluation criteria could include business plans for serving off-grid areas in a least-cost manner. Once the contract is awarded, the state could allow a higher return if the concession meets specified performance objectives relating to rural electrification.

Developing-country governments should clarify sources of funding for rural electrification as they reform their power sectors.

Regardless of what technologies are used to electrify rural areas, associated costs are generally higher than in urban areas. Developing-country governments should consider allocating a portion of the proceeds from the sale of public distribution systems to a rural electrification account that would become available to the new owners or other entities responsible for electrifying rural areas. There are many claims on these proceeds; it may make sense to combine rural electrification with other rural development initiatives.

To increase the competitiveness of off-grid options with grid extension, all current forms of public support and customer class cross-subsidies should be equally available. Moreover, the primary distribution provider should be informed that lack of progress in extending service will force the government to solicit bids from other parties to provide this service.

Power sector reforms should ensure that distributed resource options can compete fully to provide electricity services.

The distributed resource model allows grid-support, off-grid, and demand-side renewables projects to be valued fully. Improved cost accounting would enhance utility incentives to weigh grid extension against distributed resource options. Regardless of whether the utility is functionally unbundled, power sector reforms should foster careful evaluation of the generation, transmission, and distribution costs that can be avoided by distributed resource investments.

The distribution company should be required to collect information on area- and time-specific marginal costs, which would allow more accurate analysis of the cost-effectiveness of distributed applications of renewables. Time-of-use and area rates would give appropriate price signals to end-users for consideration of demand-side renewable options. Time- and location-differentiated rates could be used first in bringing service to currently unelectrified regions and then phased in for grid-connected regions.

Least-cost resource acquisition at the distribution level would ensure a level playing field among grid extension and various off-grid options. At a minimum, regulators should require distribution concessions to estimate their location-differentiated cost of service, including generation, transmission, and distribution costs. Each area (one served by a substation, for example) would have to cover its costs. This gives distribution companies an incentive to acquire off-grid resources if they are cost-effective compared with grid extension. Regulators may need to develop least-cost analytic procedures and provide training to utilities.

Regulation of retail electricity suppliers should create economic incentives that promote full consideration of renewable energy technologies on both the supply side and the demand side.

Regulators should craft retail rate formulas that are at least neutral with respect to generation technology. For example, regulators can eliminate fuel cost pass-through and other practices that treat the risks associated with various generating options differently. However, rate-making could go further. Regulators can create regulatory alternatives to cap prices and reduce retail suppliers' incentive to maximize electricity sales. Furthermore, regulators can design performance-based rate making can be designed to explicitly encourage the acquisition of target levels of renewable resources. Retail suppliers could be encouraged to develop a diverse portfolio of resources based on rate bonuses or penalties. Performance-based regulation can also create incentives for retail service providers to invest in demand-side management by decoupling profits from sales.

Power purchase agreements need to be crafted in ways that avoid biasing decisions against renewable energy technologies competing in bulk power markets.

Developing-country governments might draft and adopt model standard PPAs that provide incentives for the selection and operation of renewable energy technologies. Provisions might include:

* premium rates for projects whose environmental performance exceeds national standards;

* payment terms (such as front-end loading) that do not discriminate against renewable energy options with comparable life-cycle costs to, but higher capital cost intensity than, thermal options; and

* explicit assignment of risks and liabilities associated with future environmental controls between power suppliers and purchasers.

As one example of the last provision, power purchase agreements could specify who will bear the risk of any climate policy, such as a carbon tax, that could increase a project's future operating costs. Although the timing and nature of such carbon restrictions are uncertain thus far, this risk is quite real, especially over the 40-year lifetime of thermal power projects. If carbon restrictions were imposed, both parties would have to agree to renegotiate the PPA.

Where transmission services become common carriers, all types of generation should have equal access to transmission capacity.

Transmission rate structures should not be biased against intermittent renewable capacity. Comparable transmission pricing would help overcome barriers to intermittent or low-capacity-factor renewables. Transmission cost structures should account for intermittency in a way that is fair to all types of generation. If the demand component of transmission charges is based on a generation facility's capacity equivalence (for example, an average level of coincident peak capacity output per month) rather than maximum rated capacity, then intermittent resources would pay more than their fair share of transmission costs. The energy component of transmission costs should be based on a significant fraction of total investment in the transmission grid.

Wholesale power markets should be required to consider the environmental characteristics of competing generators.

The calculus for determining generation dispatch priority should be based on social marginal costs -

- that is, including fuel, variable operation and management, and external environmental costs. In short-term markets, the entity responsible for this would be the power pool manager. Social cost dispatch would strengthen incentives for merchant plant developers to choose technologies and fuels with low emission factors.

Realizing the Potential of Renewables

The future of renewable energy in a restructured and competitive electricity industry in the United States is currently subject to heated debate. While the interaction between power sector reform and renewables is rarely discussed in Asia, Latin America, and Africa, these regions are more likely to hold the key to the future of renewables because of burgeoning electricity demand and large populations unconnected to the grid. The massive investment in the power sector to be made in these regions holds the potential for enormous renewables markets. Whether this potential is realized depends on the path of power sector reform, which can either create new market opportunities for renewables or freeze them out. Timely interventions in the reform process by domestic policymakers, renewable energy trade groups, nongovernmental organizations, and other stakeholders would help to guide reforms in renewable-friendly directions.

*** FOOTNOTE SECTION***

1 Keith Kozloff is Project Manager at Hagler-Bailly, Inc., an energy and environmental consulting firm. Before joining Hagler-Bailly, Dr. Kozloff served at the World Resources Institute, where he wrote numerous publications on energy in developing nations. He may be contacted at 1530 Wilson Blvd., Suite 900, Arlington, VA 22209; (703) 351-0300. The ideas presented in this paper benefited from research funded by the Global Office of the U.S. Agency for International Development.

2 North America, Western Europe, Japan, Australia, and New Zealand.

3 Dennis Anderson and William Cavendish, Efficiency and Substitution in Pollution Abatement: Three Case Studies, World Bank Discussion Paper 186 (Washington, DC: World Bank,1992).

4 Anil Cabraal, Mac Cosgrove-Davies, and Loretta Schaeffer, A Best Practices for Photovoltaic Household Electrification Program, World Bank Technical Paper No. 234 (Washington, DC: World Bank, 1996); World Bank, Indonesia Policy and Operations Division, Staff Appraisal Report: Indonesia, Solar Home Systems Project, Report No. 15983-IND (Washington, DC: 17 December 1996).

5 Heidarian and Wu, Power Sector Statistics for Developing Countries, 1987-1991 (Washington, DC: World Bank, December 1994).

6 The factors driving power sector reform in developing countries are quite different than those in OECD countries. Developing countries need to attract private capital to invest in expanding and upgrading their power systems. They also recognize the need to improve managerial efficiency, accountability, and customer service. In contrast, power sector reforms in OECD countries are driven by the desire to lower electricity costs through competition.

7 John Besant-Jones, "The England and Wales Electricity Model--Option or Warning for Developing Countries?" Viewpoint (Washington, DC: Industry and Energy Department, World Bank, June 1996).

8 In the United States, this price is based on the costs that the utility avoids by not having to develop new capacity itself. Avoided costs, however, vary widely among utilities due to input

assumptions, data availability, and analytic approaches.

9 Robert Bacon, Appropriate Restructuring Strategies for the Power Generation Sector: The Case of Small Systems, Industry and Energy Department Occasional Paper No. 3 (Washington, DC: World Bank, 1995).

10 Discounting is the opposite of accruing interest--with a positive discount rate, a dollar is worth more today than in the future.

11 John Nimmons et al., Legal, Regulatory, and Institutional Issues Facing Distributed Resources Development, NREL/SR-460-217891 (Golden, CO: U.S. Department of Energy, National Renewable Energy Laboratory, 1996).

12 Although hydropower has minimal air emissions, big dams have other ecological and social impacts that complicate the environmental implications of privatization in previously hydro-dominated power systems.

13 Paul Centolla, "Wind in Competitive Power Markets: How Market-Based Policies Can Incorporate Renewable Energy Benefits," presented at Wind Energy in a Restructured Electric Industry, Washington, DC, 1994.

BOX SECTION

Box 1: Common Power Sector Reforms

For purposes of this report, the term "reform" will be used as a proxy for a broad range of changes in the power sector that could include one or more of the following:

* forming a corporation and commercializing the management of public utilities;

* introducing private-sector management or ownership of generation, transmission, and distribution assets and operations;

* creating wholesale power markets in which independent power producers sell to the grid;

* separating generation, transmission, distribution, and retail services; and

* creating retail markets in which private entities compete to supply electricity services to end-use customers.

Box 2: An Alternative Model for Power Sector Expansion

Technologies appropriate for distributed generation include modular renewables (such as photovoltaics and small-scale wind turbines) and modular nonrenewable generation (such as fuel cells and gas micro-turbines).

Although the distributed utility model has been pioneered in the United States, its characteristics appear particularly well suited to conditions prevailing in many developing countries:

* uncertain demand for power in rural areas, suggesting an incremental approach to investment;

* high transmission and distribution costs;

*	relatively low electrical demand per unit area;

*	high energy losses in getting power to the user (for example, more than 20% loss in India); and

*	unreliable interconnections and poor local power quality.

The distributed approach can help meet these challenges. Local demand peaks, which are often costly to serve, are reduced. Excess power can be sent to customers outside the immediate grid. Power quality can be improved. Finally, capital-strapped utilities can phase in needed investments. That is, local grids can be developed first and, when demand rises sufficiently, they can be connected to the transmission system.

Because the level of investment in power sector infrastructure is still small relative to the level needed to meet projected demand, developing countries could potentially leapfrog to a distributed utility model. The potential for this can be seen in countries where telecommunications systems have bypassed wires and leaped to cellular phones, and where information processing has skipped the mainframe stage and moved directly to personal computers.

Box 3: Rural Electrification

In many developing countries, governments often have required public utilities to extend the grid to rural areas -- without having tariff structures or collection ability to recover service costs. Rural electrification has thus often been implicitly or explicitly subsidized by urban electricity customers or by transfers from the national treasury. In some countries, grid extension has been closely associated with local politics, either in terms of promises made before elections to electrify, or even votes being delivered in exchange for electrification. Some utilities are reluctant to give up their political power, even though they lose money on every kilowatt-hour provided to rural customers. (Some industrial countries have also historically subsidized rural electricity services.) Because the ability to raise capital is limited, extension of the grid has proceeded slowly.

Box 4: Merchant Plants
Merchant plants are built with the understanding that they do not have specifically identified buyers to purchase their output at fixed prices over a long term (15-20 years). Instead, they sell into the market and receive whatever price it dictates for the particular day or hour.

The incentives facing merchant plant developers choosing between capital or fuel-cost-intensive generation technology are different than for plant developers with long-term sales contracts. Financing usually involves a greater percentage of sponsor equity (50% or more). This raises the cost of capital because equity capital is more expensive than debt capital.*

Because of the uncertainty over market prices and thus investment returns, merchant plant developers are likely to opt for less capital-intensive capacity than developers of dedicated capacity. Still, the merchant plant developer wants operating costs to be sufficiently low to assure a favorable (baseload) position in the dispatch order. The tension between the developer's incentives for minimizing capital cost and operating cost may be resolved by choosing natural gas generation where gas supplies are cheap.

*	J. Paul Forrester, "Wanted: A New Financing Model for Merchant Power Plants," Power Economics, Vol. 1, No. 1, February 1997, pp. 23-25.

Box 5: Argentina Rural Concessions Program

To promote the extension of services into rural areas, the Argentinean government has initiated the

Electricity Supply Program for the Rural Dispersed Population in cooperation with participating provincial Regulatory Authorities. The program gives priority to photovoltaic panels, small windmills, hydraulic microturbines, and diesel-driven generators. The total estimated investment of $314 million will be shared, with 45% paid by users, 25% from provincial subsidies, and 30% from national subsidies.

The program grants competitive concessions to one or more private enterprises in each province on the basis of lowest subsidy required per supplied user, technical qualifications, and financial qualifications. The concession will run for 45 years divided into three periods of 15 years. At the end of each period the Regulatory Authority will call for a new bidding process, with the prevailing concessionaire having priority. Rates are negotiated between the concessionaire and Regulatory Authority for five-year periods. The concession shall be exclusive for users of up to 90 kilowatt-hours per month.*

It is too early to determine the effectiveness of this approach. As of late 1996, three provinces had at least begun the process of awarding concessions, with the remainder expected to do so by 2000. Two bids have been awarded. In each case there were four to five bidders, with a wide range in the bid values offered for combined rural and urban concessions. Concessionaires, who are established utilities elsewhere, are beginning with community applications in order to gain experience in their markets. The next stage will tender separate offers for the urban and rural markets, although the same bidder may bid for both.

* A. Fabris and M. Servant, "Argentina Dispersed Rural Population Electricity Supply Program," Secretaria de Energia, Buenos Aires, Argentina, 22 October 1996.

Box 6: How Ownership Affects the Cost of Wind Energy

The ownership and associated financial structure of wind energy projects has a significant effect on their levelized cost of energy. A U.S.-based cash flow analysis found that the most expensive option is independent power producer ownership with project financing. Public utility ownership with project financing is slightly (1%) less expensive, while public utility ownership with internal financing is 12% less expensive, and investor-owned utility ownership with corporate financing is the least expensive option (29% less expensive than IPP). The factors responsible for these differences are the cost of debt and equity capital, the fraction of debt in the capital structure, and the amortization period.* While the numerical results will differ, these ownership and finance structures are likely to have a similar effect on the relative cost of renewables in developing countries.

* Ryan H. Wiser, "Renewable Energy Finance and Project Ownership," Energy Policy. Vol. 25, No.1 (1997), pp. 15-27.

Box 7: Policies for Renewably Generated Power Production in India

The Government of India's incentives to stimulate development of renewably generated power are among the most extensive in the world. The central government offers deep tax concessions, below-market financing, and other schemes designed to promote renewable power development. In several states, State Electricity Boards will buy power from renewable developers at quoted rates and allow them to sell power elsewhere using the transmission system. In February 1997, the central ministry announced that it expects 10% (1,000 megawatts) per year of new capacity additions to come from renewables.

Specialized programs and policies for renewables have stimulated their market penetration, but they also isolated renewables from mainstream power sector decisionmaking under the Ministry of Power. India's power sector reforms have proceeded largely independently of its policies for renewable energy. As power sector reforms and privatization move ahead, separate policies and subsidies for renewables will become difficult to maintain. In addition, the overall trend of devolution of political power to the states means that each state's reform policy will become more important.

TABLES and BOXES

TABLE 1: EXAMPLES OF RENEWABLE TECHNOLOGIES IN DEVELOPING COUNTRIES

RESOURCE	BULK POWER (less than 10 megawatts)	DISTRIBUTED POWER (greater than 10 megawatts)
Wind—Long used for pumping water and other mechanical uses. Though generally stronger in temperate regions, resources are sufficient to produce thousands of megawatts of power in Asia and Latin America.	Wind farms consist of many turbines clustered together to generate power for the grid. Capacity in developing countries is still small but growing rapidly in India.	Small wind turbines for village or farm use.
Direct solar radiation—Used for concentrating collectors; highest in regions with little cloud cover. Diffuse solar radiation is widespread in the developing world.	Solar thermal technologies concentrate sunlight to heat a fluid and produce electricity. Not yet commercially deployed, although several demonstration or pilot projects exist.	Photovoltaic (PV) installations already serve tens of thousands of household and have other uses in Asia, Latin America, and Africa. At present costs, used primarily to supply individual users far from electricity grids, and central PV power stations for remote villages. Other applications include lighting, water heating, and space heating.
Biomass—Direct combustion of agricultural and forestry residues for combustion in turbines. Processing sugarcane, rice, coconut, and other tropical foods creates organic waste that can be burned directly or gasified.	Bagasse (sugarcane residue); cogeneration (combined heat and power).	Village-level combined gasifier/power generators or direct combustion.
Hydro—Among the most mature renewable technologies; used for many years to power rural areas. Only about 10 percent of the developing world's potential small hydro capacity has been exploited.	Large-scale hydro has been a mainstay of the generation mix in many developing countries but is controversial due to ecological and social impacts. Smaller scale (10–50 megawatts) installations are being developed.	Minihydro (up to 5 megawatts) and microhydro (less than 100 kilowatts) generators for individual and community applications.
Geothermal—Untapped geothermal resources can be found on both sides of the Pacific Rim (especially Bolivia, Chile, Costa Rica, Guatemala, and Thailand) and in the East African Rift Valley.	Central station hydrothermal generation. Installed geothermal capacity in developing countries is projected to grow from about 2,000 megawatts in 1993 to about 5,000 megawatts in 2000.	High efficiency generation for local grids.

TABLE 2: SUMMARY IMPLICATIONS OF POWER SECTOR REFORMS FOR RENEWABLE ENERGY MARKETS

Key: + = favorable
- = unfavorable
0 = depends on implementation details

Reform	Effects in Bulk Power Markets	Effects in Distributed Power Markets
Commercialization	Greater attention to environmental implications of power generation (+)	Greater sensitivity to cost recovery favors grid support and demand side applications (+)
Privatization	Higher discount rate favors fuel-cost-intensive generation options (-) Power purchase terms favor development of nonrenewable generation (-)	Decreased interest by utility in serving unelectrified rural areas (-) Tariff reform improves end-user price signals to consider off-grid and demand side applications (+)
Unbundling	Contract terms may or may not allow renewables greater transmission access (0)	Ability to capture system benefits from deploying distributed resources depends on structure and tariff regulation (0)
Wholesale Competition	Short-term markets not oriented toward renewable generation characteristics (-)	Greater uncertainty in future cost of grid power may discourage investments in distributed applications (-)
Retail Competition	Retail suppliers want to minimize fixed costs to reduce competitive exposure, which reduces interest in capital-intensive renewables (-)	Incentive to maximize kilowatt-hour sales and maintain competitive rates discourages retail supplier investments in DSM (-) unless suppliers offer DSM to distinguish themselves from competitors (+)

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