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**SOME LIGHT AT THE END OF THE TUNNEL* Ingredients of
Power Sector Reforms in India**

“What we learn to do, we learn by doing.”

-Aristotle

Nichomachean Ethics

by

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1. INTRODUCTION

Electricity is a catalyst for development. Its use contributes to household welfare by facilitating education, sanitation, and other basic family investments in health and wellbeing. As an intermediate input for which substitution by other inputs is often difficult, electricity powers irrigation pumps, industrial machines, computers, and other basic inputs into production. The high-tech sector, in particular, relies on not only adequate supply but also reliability of electricity. The competitiveness of Indian industry relies on both reducing high prices and increasing the reliability of electricity supply.

The question is how to provide this service at the lowest cost possible.¹ The quality and coverage of electricity in India today leaves much to be desired. Nearly 61% of Indian manufacturing firms own generator sets, versus 20% in Malaysia, 27% in China and 17% in Brazil. India's blended real cost of power is 74% higher than Malaysia's and 39% higher than China's.² Electricity problems are estimated to wipe out a 9% of value added production.³ Consumers suffer daily power interruptions, and a single substation failure can take down an entire regional network affecting millions of people.⁴ As India's growth accelerates, the unmet demand for electricity is increasing.

Without additional capacity addition or improved demand side management, the power shortages endemic to most regions of India will continue into the future. The Ministry of Power's estimate that an additional 100,000 MW of generating capacity will be needed to provide power for all by 2012 is likely to be an outer bound, since it assumes no

¹ By "cost" we refer to the cost of electricity production, transmission, and distribution to final customers. This may (obviously) be different than the price. We discuss pricing as a means to motivate efficient, lowest-cost production rather than as an end in and of itself.

² Cross country comparisons of tariffs are somewhat ambiguous due to differences in the quality of power supply, the pricing regime, and questions about the appropriate exchange rate for conversion. Varying assumptions can significantly affect conclusions from international comparisons. See, for example, Yamada (2002). The general magnitude of the China-India comparison, however, is telling.

³ World Bank – CII (2004).

⁴ A substation failure in Uttar Pradesh, for example, caused the entire Northern grid to fail for 12 hours in January 2001, leaving 226 million people without power. Several years earlier the eastern grid failed, leaving West Bengal and Bihar blacked out for several days.

reduction in demand as the pricing regime changes to reflect the true costs of supply.⁵ Nevertheless, it may not be too far off the mark if the possibility of more reliable service and removal of cross-subsidization from industry to consumers and agriculture lead to increased industrial demand over the coming decade. In any case, adding this capacity will require Rs. 9 trillion of investment, not including the costs of restructuring state utilities and taking care of past liabilities as well as working capital, etc during the transition period.⁶

India's enormous geographical size, dispersed population, and regionally concentrated energy sources pose particular challenges for infrastructure design. Governance of the sector is also complicated by the fact that power has been a concurrent responsibility of center and state governments since the Constitution of India took force in 1950.

Private companies were the initial entrants into India's power sector in the late 1890s. They solved the geographical diversity problem by focusing efforts on supplying cities and larger commercial areas, leaving the less commercially viable rural areas aside. The public sector took over and combined the private suppliers after Independence in 1947, establishing government dominance in generation, transmission, and distribution.

State Electricity Boards (SEBs) thereafter oversaw generation, transmission within the state, and distribution. As demand increased, the central government also developed larger thermal and hydroelectric plants in the 1970s. The central government was responsible for the inter-state distribution network. While this state-led power sector development was effective in increasing installed capacity and extending the electricity network to many previously underserved rural areas, government provision of electricity over the years has not proven to be a sustainable enterprise. Government ownership without competition did not create incentives for efficient generation, or maintenance and expansion of networks. Policymakers used provision of low-cost electricity to gain

⁵ A recent (September 2004) Planning Commission review of the National Electricity Policy argues that the mere provision of household access would only require a 15-20% expansion of the generation, transmission, and distribution system. Jog, Sanjay (2004). "Redraft Power Policy: Plan Panel" *The Indian Express* September 21, 2004.

⁶ Ministry of Power, Government of India (2002a).

support, crippling state and federal government utilities' ability to cover costs and muting any market signals. India's power sector was thus unprepared for the increase in demand starting with the growth increase of the late 1980s.

The 1990s brought a fundamental policy shift toward "corporatization" of the power sector by restructuring monolithic State Electricity Boards (SEBs), including the private sector in provision of electricity, and developing new regulatory oversight to prevent abuse of market power. The initial phase of the reforms focused on attracting private investment in generation with government guarantees and involved little attention to the underlying source of risk: the distribution sector. The second wave of reforms, this time led by state-level efforts to separate SEBs into generation, transmission, and distribution components as well as, in some cases, privatize, attempted a broader set of reforms offered more lessons than solutions.

This paper focuses on the third wave of reforms, which we date as beginning in the late 1990s or 2000. These central government-led reforms are different from previous attempts in two ways. First, they address the weakness of the distribution sector and, to a lesser extent, regulatory oversight. Legislation, expert recommendations, and, perhaps most importantly, fiscal incentives have been employed to address State Electricity Boards' bankruptcy, the lack of metering, the extensive "transmission and distribution" losses (more descriptively known as "theft and dacoity" losses⁷), and other issues that detract from the sector's performance as well as its attractiveness for investors. As we discuss below, the pace of these changes, however, has depended on the interaction between state and central policymakers.

Second, the reforms envision a much greater change market structure than has previously been proposed. The Electricity Act of 2003 proposed a more radical restructuring of the electricity sector as well as a much larger role for the private sector than had been contemplated before. The Act itself creates the legal framework for moving away from a

⁷ An estimated 10-15% of power generated is lost to theft, and an additional 15% to technical losses.

single-buyer model, while subsequent policy discussions and decisions have moved toward a goal of a wholesale power market.

The reforms combine a “back to basics” element with a “leap for the stars” component. This chapter, like Frank Wolak’s chapter in this volume, argues that continued attention to the first is essential for the success of the second. Our chapter differs from Wolak’s, however, in the framing of our analysis. Given the reforms’ legislative and bureaucratic momentum and the existing commitments to the new model, we ask “What would it take to establish the kind of market envisioned?” rather than advocate a different path altogether. Although there are clearly risks involved in moving quickly to a wholesale power market, India, of all developing countries, is one in which such a plan could succeed. It has a large market as well as a substantial pool of well-trained engineers and software developers.

This paper’s goal is to engage the ongoing general policy dialogue and emphasize priorities. The underlying policy implications in this paper are similar to Wolak’s chapter: do not invest in creating a wholesale market before investing in creating effective regulators and clear policy jurisdictions, removing capacity constraints, and ensuring that the distribution sector is either viable or on a clear path to being so. We are slightly more optimistic about India’s initial conditions, however, and document the reforms already underway in the distribution sector. While these are still limited in absolute terms, they are a significant move forward compared to India’s earlier approach to reform in the power sector.

Section Two provides an overview of the physical and policy infrastructure as well as a short history of the electricity sector over the past century. Section Three discusses the trajectory of reform efforts up to the mid 1990s, primarily focused on the center and state governments’ early efforts to attract investment in generation as well as beginnings of restructuring in various states.

Section Four documents the progress in the “back to basics” reforms. These are small, but significant steps forward and must remain a central part of ongoing policy changes.

Achieving a financial viable – or even close to viable – distribution sector contributes to achieving the longer-term goal of a new market structure by making investment in transmission and generation capacity more attractive. Distribution sector reform also sends a powerful signal of the government’s commitment to reforms - it is not the only measure of commitment, but it is a strong one because it is politically difficult to raise prices and reduce subsidies for electricity supply for groups that represent a large segment of the vote.

Section Five turns to analyze the “leap for the stars.” We summarize key elements of the Electricity Act of 2003 and subsequent discussions. We focus in particular on the recommendations laid out in the recent (2004) report of the Planning Commission’s Task Force for Power Sector Reforms (chaired by N.K. Singh). Some of these have been implemented, while others are under discussion and review.

Section Six discusses the physical and institutional investments that must be made before moving further toward setting up the technical infrastructure for a competitive market. On the physical side, investment – both public and private – must be channeled into increasing transmission capacity to remove bottlenecks. Investment incentives must be structured to ensure that more players are able to enter the generation and distribution sectors – not just that existing players become larger. On the institutional side, regulators’ technical skills and independence must be strengthened – a break from recent history must be achieved. One of the regulators’ first tasks, which will require substantial political insulation, will be to alter pricing regimes, particularly retail pricing and cross-subsidization policies, to make further investment viable facilitate competition in distribution. The division of responsibilities and jurisdictions between state and central government should also be re-examined and the costs and benefit of the current relatively decentralized structure assessed. The Constitution’s list of “concurrent subjects” mandates that authority over the electricity sector be shared by center and states, but the

most efficient manner of doing so is open for further discussions and legislative action if considered appropriate.

Section Seven concludes with a reiteration of the need to prioritize distribution sector reform and to establish and enable credible regulators. Imposing and enforcing cost-of-service related user charges is one of the most important priorities: it would contribute to the investment climate, encourage demand-side management, and reduce the fiscal drain on all levels of government. We also discuss other areas for future consideration.

2. PHYSICAL INFRASTRUCTURE

As of April 2004, India had 112,058 MW of installed capacity, an increase of about 55% over the level at the start of the 8th Plan in 1993.⁸ It is not clear how much of this capacity is actually operable – due to inadequate maintenance some plants may actually be capable of producing at their rated capacity. Figure 1 shows installed generating capacity at that point.

Regions vary substantially in installed watts per capita. [Table 1] The islands have the highest installed capacity per capita, with 166.17 watts per person – this would be necessary to meet fluctuating demand since the area is naturally unconnected to the national grid. The western and southern regions follow close behind with 140 and 131 watts per capita respectively. The Northeast lags behind with just over 60 watts of installed capacity per capita.

Table 1

Region	Installed Capacity (MW)	Watts per capita	% Hydro	% Thermal	% Wind	% Nuclear
North	30980	100.84	34.20	61.79	0.20	3.81
West	32178.8	139.75	15.47	80.32	1.86	2.36

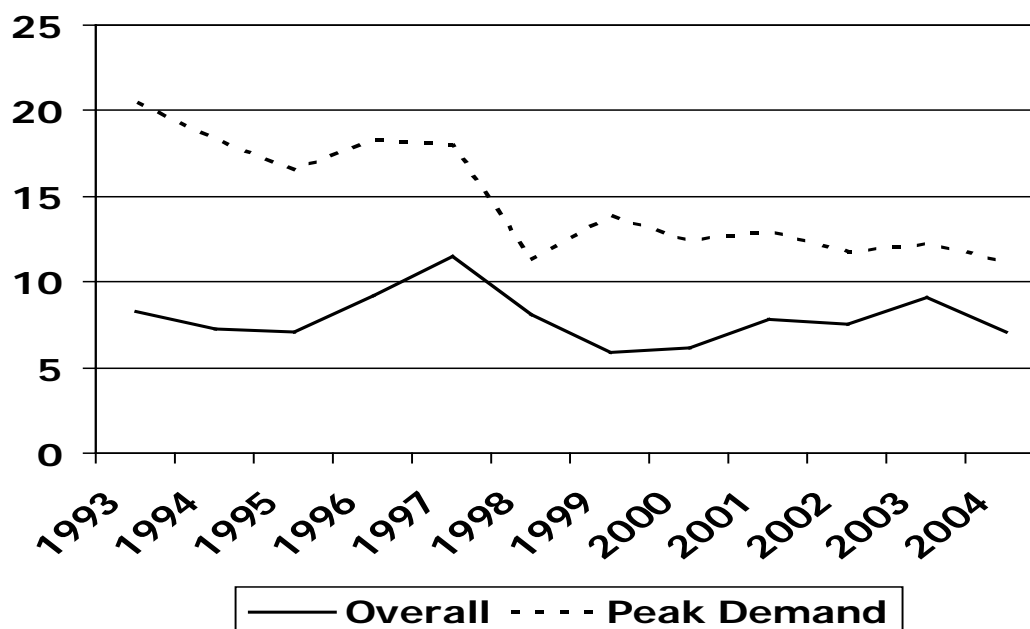
⁸ These and subsequent capacity figures are from the Ministry of Power Annual Report 2003-2004.

South	29299.26	131.16	35.25	57.96	4.13	2.66
Eastern	17196.68	75.67	14.30	85.68	0.02	0.00
Northeast	2334.41	60.64	48.57	51.42	0.01	0.00
Islands	69.27	166.17	7.58	92.42	0.00	0.00
All India	112058.4	103.44	24.79	71.16	1.51	2.53

Source: Authors' calculations based on statistics on power from Ministry of Power Annual Report 2003-2004, population statistics from Census 2001. Regions as defined by Ministry of Power: North (Delhi, Haryana, Himachal, J&K, Punjab, Rajasthan, UP, Uttranchal, Chandigarh), Western (Goa, Daman & Diu, Gujarat, MP, Chatisgarh, Maharashtra, Dadra & Nagar-Haveli), Southern (Andra Pradesh, Karnataka, Kerala, Tamil Nadu, Pondicherry), Eastern (Bihar, Jharkhand, West Bengal, Orissa, Sikkim), North-eastern (Assam, Arunachal Pradesh, Meghalaya, Tripura, Manipur, Nagaland, Mizoram), Islands (Andaman & Nicobar, Lakshadweep)

Base load power shortage hovered between 8-11% over the 1990s. The gap between supply and demand increased steadily from 1998-99 (5.9%) to 2002-3 (9.1%), but dropped to 7.1% in 2003-4. Shortages of peak power have been more severe but have also declined more noticeably over the decade. The shortage was 20.5% in 1992-3, but only 11.2% by 2003-4. (Figure 2) The demand estimates are likely to be inflated, however, by the low cost of power for agricultural users and consumers, as well as the de facto zero price of stolen power.

Figure 2



Most of the power supply is based on conventional thermal generation, with just over 2% from nuclear power and about 25% from hydropower. About 70% of the conventional thermal plants are coal-based, though natural gas is increasingly being used. As shown in Table 1, the mix of power sources varies across regions. The Northeast relies on a nearly even mix of Hydro and Thermal Generation, while the Islands and western region are far more dependent on Thermal generation. Wind power is most prevalent in the South, where over three percent of installed capacity is wind power. Nuclear power is concentrated in the Northern region, with some also in the West and South.

Recent capacity addition has been mainly in thermal power generation and has not taken advantage of a large untapped potential for hydroelectric power, which tends to be lower cost than thermal generation.⁹ Hydropower, however, is substantially more variable over seasons and is particularly risky if inter-regional transmission capacity is low and hydropower cannot be augmented during droughts. The location of generating plants is also (obviously) somewhat limited and extra supply will not be transferable to other regions without increased transmission capacity.

The state governments typically supplies just over half of each region's power, with the split between central government and private sector varying more across states. [Table 2] The West and South as well as the Islands have the most significant private sector participation.

Table 2

Region	% State Government	% Central Government	% Private
North	56.16	42.42	1.42
West	60.87	21.40	17.73
South	63.59	22.59	13.82
Eastern	46.02	45.60	8.38
Northeast	46.05	52.90	1.05
Islands	71.13	0.00	28.87
All India	59.37	30.89	9.75

⁹ The National Hydroelectric Power Corporation of India (NHPC) plans to add 4357 MW of power during the 10th Plan (2002-2007) and 15, 208 MW during the 11th Plan (2008-2013)

The bulk of transmission is within the regions listed in Table 1 above. Inter-regional transmission accounts for 25-30 percent of total power transmission. The grids often operate at different operating parameters: chronic surpluses in the East and shortages in the South, for example, have resulted in sustained functioning of these grids at frequencies beyond the regulated bound of frequency variation within 49.5 to 50.3 Hz. Transmission networks provide inter-regional transfer capacity of about 5,000 MW as of the end of fiscal year 2002-3. Links between the West and South, providing a maximum power transfer capacity of 1,000 MW, are the best developed, while East-West offer only 150 MW of maximum transfer capacity.¹⁰ The Ministry of Power plans to build up transfer capacity to 29,500 MW by 2012.¹¹

The Central Government-owned PowerGrid Corporation of India Limited (PGCIL) provides the bulk of inter-regional connectivity, with state transmission utilities providing much of the rest of the infrastructure. Private participation in transmission is likely to increase under the new legal provisions of EA 2003.¹² The Central Electricity Regulatory Commission (CERC) also issued a transmission license to Tala Delhi Transmission Company Ltd., a JV Company between POWERGRID (49%) and Tata Power (51%) in October 2003.¹³ Several other private projects, including a request for a JV between Malaysian company Tenage and Gujarat for the Bina-Nagda sector, and Reliance's application for transmission license for 20 lines and 13 substations in the Western region, are under consideration.¹⁴

¹⁰ Figures are from "Details of Existing Inter-Regional Links," from the Central Electricity Regulatory Commission (CERC) website. <http://www.cercind.org/powergrid.htm#Existing%20Inter>. Additional projects were commissioned in 2003 to increase total inter-regional transmission capacity by 60% (8000 MW from 5000 MW) but were not complete at the time of writing.

¹¹ MOP 2003, Statement –VII

¹² The 1998 Electricity Reform Act identified it as a separate activity and allowed private participation in operations and maintenance, but private ownership and management has only been allowed since EA 2003.

¹³ The transmission line would take power from the 1020 MW Tala Hydro electric project in Bhutan. The 1200-km transmission line costing Rs.1200 crores is expected to be commissioned in 2006.

¹⁴ The Bina-Nagda project was originally refused on the grounds that the private company's proposed project costs were substantially higher than those estimated by the public utility. This logic was overturned amidst public sector cost overruns and the Central ERC is reconsidering the matter.

The SEBs are the primary distributors of energy, though, as in transmission, private sector involvement is likely to grow in the new legal environment. Distribution has been privatized in Delhi, Maharashtra, and Orissa, and other states are likely to follow. Distribution is also in private hands in the cities of Calcutta and Ahmedbad. Reliance Energy has approached the Maharashtra Electricity Regulatory Commission and the Delhi Electricity Regulatory Commission for a distribution license using its own distribution system.

3. HISTORICAL CONTEXT OF ELECTRICITY SECTOR REFORMS

Electricity was originally provided by private companies. Kolkata was the first city to be electrified in 1897 by the Calcutta Electric Supply Corporation, while Mumbai was electrified shortly thereafter. Several other private companies provided power for smaller urban areas under franchise arrangements with the state governments.

At Independence in 1947, most of these companies were nationalized and the electricity sector came to be regarded as a “public utility.” Provision of electricity was determined to be a “concurrent subject” under the Constitution of India and thus a joint responsibility of the central and state governments.

The 1948 Electricity Supply Act charged the SEBs with generation, transmission, and distribution. It also created the Central Electricity Authority (CEA), a federal entity that approved larger power sector projects and served in an advisory role, to coordinate policies across states, but the SEBs were the primary policymakers. The Central Power Sector Utilities (CPSUs), including national thermal (conventional and nuclear) and hydro generators and the Power Grid Corporation of India Limited (PGCIL), stepped in subsequently with larger-scale generation projects and more extensive inter-state transmission grids. Capacity increased from about 1300 MW at the time of Independence (1947) to 90,000 MW in 1991, enough to keep up with rising demand over this period. As mentioned above, the gap between supply and demand became apparent over the 1990s, however, even though installed capacity rose to 112,058 MW by early 2004.

Other limits to public provision became clear in the late 1980s and 1990s. The original rationale for government ownership had been that electricity provision was a natural monopoly, that only the public sector would have incentives to provide even the poorest with access to electricity, and that only the public sector was capable of financing such large-scale infrastructure. This rationale became less persuasive over the last two decades of the 21st century.

The first two arguments do not imply that public ownership is necessary, but only that some public regulation was needed. And even this need for regulation has narrowed as technological advances allow unbundling of generation, transmission, and distribution sectors, some of which are potentially competitive. The costs of public ownership, on the other hand, became more apparent over this period. Consumers accustomed to free electricity were disinclined to pay user charges. Policymakers seeking public support have little incentive to extract payments for the full costs of service. Limited competition in power provision reduced any incentives for efficient generation, or maintenance and expansion of transmission and distribution networks.

The third argument, that only the public sector had resources for financing such infrastructure, lost currency as rising fiscal deficits at all levels of government squeezed investment. States' deficits made it very difficult for them to provide investment finance for State Electricity Boards, while the Center's deficit (which fell in the first half of the 1990s but subsequently climbed to new heights) meant that it could neither provide relief or maintain and invest in new generation capacity or transmission infrastructure. This fiscal crunch, more than anything else, probably drove the incentives for looking to the private sector for funding.

The State Electricity Boards, under political control of the state governments, had limited ability to collect tariffs, particularly from agricultural users who rely on electric pumps for irrigation. Connections to agricultural users were largely unmetered and even metering to urban consumers was inadequate. Then, as now, industrial consumers paid

the bulk of tariffs collected.¹⁵ SEBs' operations were heavily subsidized, creating little incentive for efficient production, transmission, and distribution of electricity. The SEBs underinvested in transmission and distribution facilities, leading to large losses of electricity and severe burdens on state government budgets. Transmission and distribution losses have also been recurring problems.¹⁶

As state governments' finances deteriorated and the subsidies to SEBs could not be sustained, the SEBs began to default on or underpay obligations to other generators who supplied them with power. These problems were compounded by a rapid increase in demand for power as India's growth rate accelerated in the late 1980s and 1990s.

The Central Electricity Authority's (CEA) "Report of the Committee on the Fixation of Tariffs for Central Power Sector Stations," a critical discussion of the then prevalent single-part tariff marks one of the first responses to the growing financial distress of the SEBs.¹⁷ In addition to documenting the growing disputes between central public sector utilities and the SEBs over tariff levels and timeliness of payment, the committee (chaired by K.P. Rao) recognized that single-part tariff provided strong temptation for suboptimal use of power from different sources and resulted in per-unit costs that were much higher than the marginal costs of an additional unit of power generated by the generally newer, larger, and more efficient CPSUs. According to the SEBs, part of the problem was that the "normative" parameters for fixed costs and operating costs substantially overstated the true costs so that it was not worth their while to purchase power from the CPSUs instead of using their own generating facilities. CPSUs' response was that the normative operating parameters, while providing a cushion and increased profits, still implied lower

¹⁵ Agricultural tariffs and cost of service vary from state to state. Even the highest prices for agricultural power, 90 paise/Kwh (in Maharashtra in 2002), is still less than a third of typical service costs of over 300 paise/Kwh. Commercial and industrial users paid nearly 10 times the tariffs farmers paid in 2002: the averages for commercial and industrial users were 429.21 and 381.14 paise/Kwh respectively, compared to farmers' average tariff of 41.54 paise/Kwh.

¹⁶ The long low voltage lines extending to rural areas are particularly easy to tap, and difficult to monitor and remove illegal connections. The copper lines are also sometimes stolen and sold for the value of the metal.

¹⁷ A single-part tariff consists of a flat rate charged per unit of energy used, regardless of actual cost of production. It is generally designed to recover the fixed costs of generation calculated on the basis of normative depreciation, capital costs, and other parameters set by the regulator.

costs than the SEBs' generating facilities were achieving. Boards that could meet their requirements through their own generating capacity turned to the older, less efficient plants to do so. In some cases centrally owned hydro stations were allowing water to flow without generating power, while the Boards were using fossil fuels to generate power in their thermal power stations. The report suggested switching to a two part tariff that separated charges for fixed costs including interest on loan capital, depreciation, O&M expenses, income taxes, return on equity, and interest on working capital and variable costs, namely fuel. The return on equity was determined after actual costs were considered.

This framework of two part cost-plus tariffs was put into place in 1991 and was the basis for contracts with new private sector generating companies as well as more general regulation throughout the 1990s (and up to the new April 2004 regulations). Its main infirmity quickly became apparent: the cost-plus regulation gave generating companies little incentive to keep costs down. Higher power costs placed even greater strain on the SEBs. Rising payments for purchasing power were the main source of the growing disparity between tariffs and cost of service.¹⁸

The Government of India also began to seek private investment in generation capacity to supplement public investment in 1991. The central government's initial strategy consisted of offering guaranteed 16% rates of return to independent power producers (within the two-part framework mentioned above). The central government put eight projects on the "fast track," with streamlined approval procedures and sovereign repayment guarantees so that investors did not have to rely on the bankrupt SEBs.

In and of themselves, these projects provided a small part of the new generation capacity required and ended up being extremely costly, but the hope at the time was that they would serve as "showcases" to catalyze further investment in the sector. State governments were encouraged to sign Memoranda of Understanding with independent

¹⁸ Pay raises mandated by the Fifth Pay Commission also contributed to the gap. Planning Commission, Government of India (2000)

power producers, with standards for transparency imposed only after the process had started. The states appeared to be rushing to sign MOUs - in one example, the Andhra Pradesh government and SEB signed MOUs for more than a dozen Independent Power Producer projects in one night – to beat central government deadlines for moving to competitive bidding.¹⁹ Only a few of the 189 projects for which there were MOUs or Letters of Intent passed the central government’s techno-economic clearance.²⁰

This initial effort, in retrospect, seems doomed to failure because it did not address the fundamental financial weaknesses of the electricity sector, the SEBs’ losses. At the end of the 1990s, the same factors contributing to SEBs’ initial financial weakness were at work. Only 55% of total power generated was billed and even less, 41%, was actually paid for. SEBs’ average cost recovery through tariffs was only 74% in 1999-2000, 6% lower than in the beginning of the decade. Losses were over Rs. 330 billion in fiscal year 2002-2003.

Tongia (2003)’s analysis of the political economy of power sector reform asks the incisive question: “Why did central government focus so hard on increasing supply as a solution to electricity unreliability, especially when it just meant increasing losses from bankrupt SEBs?” (45)

The state governments, in the meantime, began to restructure their power sectors in more fundamental ways by breaking apart the monolithic SEBs into potentially competing generation, transmission, and distribution companies. The World Bank also provided impetus for these reforms: changes to the electricity sector were assigned high priority in the lending programs from the World Bank to state governments.²¹

The relatively poor state of Orissa was a reform leader at this point, unbundling its SEB in 1996 and creating two generation companies, one transmission utility, and four

¹⁹ Prayas (2001).

²⁰ Tongia (2003).

²¹ Dubash and Rajan (2001) emphasize that the reforms were catalyzed by the World Bank’s offer of a loan to support electricity restructuring, but that they were “tailored” to the Indian context and were politically supported within the state.

distribution companies by 1998. It also privatized its distribution by 2000.²² Other states, including Andhra Pradesh, Haryana and Rajasthan, followed suit with more moderate changes including administrative separation (though not privatization) of the various parts of SEBs, creation of State Electricity Regulation Commissions (SERCs), and private involvement in generation. More recently, Delhi has privatized distribution.

As with the IPP fast track guarantees, the states' (particularly early reformer Orissa's) reforms were intended to be a showcase to attract further support for reforms. It is difficult to evaluate the effects of state-level reforms after such a short time period and without a history of data collection,²³ but they are generally seen more as learning experiences than showcases. Privatization had little effect on distribution losses in Orissa, increased generating costs, and saddled the state-owned transmission company with mounting losses. A state-appointed review committee headed by Sovan Kanungo found that the private distributors AES Corporation and BSES did not bring sufficient management expertise or working capital. Collection efficiency actually decreased from 84% to 77% and the distribution companies defaulted on payments to their sole supplier, the state-owned GRIDCO. Privatization also increased the value of generation assets and thus the costs of power for the sole buyer (GRIDCO). The transmission company was squeezed in the middle and its loan burden increased from Rs. 820 crore to Rs 3,300 crore over 1998-2001.

The roots of the state reforms' disappointing short-term effects are still being untangled.²⁴ In addition to the shortcomings cited above, much of the blame for Orissa has been centered on contracts that overpaid generators, short-sighted regulation that offered little incentive for distribution companies to improve performance, and lack of a transition plan for subsidizing parts of the sector until tariffs could be brought in line with

²² Orissa's relatively small power sector, and limited agricultural population seem to have been important advantages in moving restructuring forward.

²³ Andhra Pradesh's published Transmission and Distribution losses, for example, jumped from 19-22% over 1981-1996 to 32% in 1997, most likely because previous figures had been manipulated to satisfy funding agencies but the 1997 figure was based on more transparent accounting. Prayas (2001), p.35.

²⁴ We emphasize that the problems outlined above may be a short-term disappointment. The BSES distribution companies in Orissa, for example, appear to have broken even in their operations as of May 2004.

realistic supply costs. Orissa's experience also demonstrated the potential pitfalls of making the transmission utility an intermediary between generators and distributors. The Electricity Act of 2003's emphasis on open access and facilitation of contracts between generators and several distributors reflects this lesson.

Reviews of other states' experiences emphasize the lack of transparency in awarding contracts and lack of credibility of regulators.²⁵ Privatization has also been slow due to lack of private sector interest. In Delhi, for example, the April 2002 privatization of three distribution companies was delayed because only two private companies were bidding as of May 2002, and not even making bids that met reservation parameters.²⁶ The north and northwest distribution sectors were taken over by a joint venture between one of the bidders, Tata, and the government of Delhi after negotiations.

Several central government legislative changes occurred in the 1998, but these did not fundamentally shift the dynamics of reform. The Electricity Act of 1998 created the Central Electricity Regulatory Commission to develop national regulatory guidelines and regulate tariffs for central government-owned utilities, but the financially weak state public sector utilities remained outside its jurisdiction. The Electricity Regulatory Commissions Act of 1998 supported ongoing state-level reforms by *enabling* states to form independent electricity regulatory commissions (SERCs), but did not require states to carry out any reforms.²⁷ The SERCs formed had varying degrees of political independence. Although the central government and CEA was able to influence the states through its control over techno-economic clearance and its ability to specify operating norms and set the tariffs for central generating stations, consumer tariffs during this period were mostly set by the state governments and SEBs. State governments, the owners of most of the electricity sector, were in charge of regulating themselves – a situation with obvious drawbacks.

²⁵ Prayas, Indian Power Sector Reforms Update – Issues 1-5.

²⁶ Prayas (2002b).

²⁷ The legislation, however, made it easier for private companies to sue state governments to demand formation of a regulatory commission. The Maharashtra ERC, for example, was formed by High Court order on a case filed by an industry association.

The latest wave of reforms, however, beginning roughly in 2001, differs from this historical trajectory in two ways. First, the government has begun to address underlying weaknesses in the power sector that had been neglected in the initial attempts to attract private investment in generation. This is still on an ongoing process, and few would say that the power sector is on firm financial and institutional ground yet. Nevertheless, the policies implemented in the wave of reforms since 1998 should be recognized as an important advance over the initial attempts to attract private power projects in the early 1990s. Second, as we discuss in Section Five, the Electricity Act of 2003 and subsequent policy proposals represent a far more radical change in the sector's basic economic model as well as the role of public and private participants. Whether or not this will be beneficial depends on concerted attention to continuing efforts to shore up the public sector. The central government has gradually increased its role as a coordinator of state reforms through combination of financial incentives, legal changes, and more concerted reform efforts of its own.

4. ATTENTION TO THE DISTRIBUTION SECTOR

The first policy indication of a new approach was the creation of an Expert Group, chaired by Montek Ahluwalia (then member, Planning Commission), in 2001 to recommend measures for a one-time settlement of SEB arrears and suggest strategies for capital restructuring to improve these entities' credit ratings. The recommendations that states issue bonds for part of arrears, and agree to conditions for reforms as well as improved revenue realization in exchange for some debt forgiveness have largely been followed.

The Government approved a one-time settlement of the SEBs' outstanding dues in March 2002. Sixty per cent of the surcharge/interest on delayed payments would be waived for participating States, while the rest of the dues and the remaining 40 per cent of the surcharge/interest would be securitised through tax-free bonds (at 8.5% annual interest rate) issued by the respective State Governments. Looking forward, defaults in current payment for power or fuel would be punished with a reduction in the supply of power

from central power stations and in coal supplies. Defaults of over 90 days would be recovered through deductions from central government transfers to the states.

All states have signed agreements for the one-time settlement and either issued bonds or made other arrangements for securitizing outstanding dues.²⁸ It remains to be seen whether this one-time settlement will have any long-term effect on SEBs' finances, as such schemes inevitably create potential moral hazard due to the difficulty of guaranteeing that the settlement will not be repeated in the future. As of February 2004, the arrangement has resulted in improved collection of current dues to central public sector utilities.²⁹

The appointment of several expert groups to study policies to improve distribution sector performance is another indication of increasing attention to strengthening the distribution sector (rather than repeating the mistake of emphasizing generation first). An Expert Group under Ashok Basu (then Secretary, Minister of Power) provided a timeline for improving distribution efficiency and determining a model for privatization. An information technology (IT) task force was formed under Nandan Nilekani, (CEO, Infosys) to look into IT solutions for improving service quality and reducing distribution losses.³⁰

One of the most significant developments, however, has been the central government's use of its fiscal leverage to push for adoption of the Expert Groups' recommendations. The Accelerated Power Development Program (APDP), established in 2000-1 to provide transitional financing for the states, was transformed (along with an nearly doubled budget) into the Accelerated Power Development and Reform Programme (APDRP) in 2002 following recommendations of the Expert Group headed by N.K. Singh (member, Planning Commission). A separate Expert Committee, under Deepak Parikh (chairman,

²⁸ Most states issued bonds, however the National Capital Territory of Delhi securitized its outstanding dues by converting them into long term advances payable to the Central Public Sector Utilities. (Ministry of Power 2004).

²⁹ Ministry of Power (2004). P. 12

³⁰ See Tongia (2004) for a critique and alternate proposal for reforms.

Housing Development Finance Corporation) provided many of the specific milestones. The incentives are explicitly aimed at improving the distribution sector.

Resources- in the form of grants and loans – are distributed on the basis of progress in installing meters, creation of independent SERCs, reduction of transmission losses and other specific, measurable milestones. Independent evaluations by ICRA and CRISIL ratings agencies have also been a factor in determining the distribution of resources since 2003.

The conditions for funding generally include deadlines for corporatizing SEBs, setting up regulatory commissions, installing meters, achieving break-even operation of distribution, and providing electricity for rural areas. The MOUs lay out very detailed conditions in areas where reforms can be broken down into concrete, monitorable, stages such as installation of suitable meters, securitization of outstanding dues to the Central Public Sector Utilities, and funding support for particular power projects. They are more decentralized in other areas where goals are clear but appropriate means may vary across states. They set out time paths for reducing transmission & distribution losses, for example, but do not spell out the steps toward the goal. The MOUs require states to formulate policies for outsourcing billing, meter reading, and maintenance, for example, but do not specify exactly how this should be done. States are also given incentives to reduce cash losses by being allowed to keep any money saved after accounts are independently audited.

All states have signed Memoranda of Understanding (MOUs) with the central government, in which the central government provides upgrades to inter-state transmission lines, more power supplied from central generating stations, grants-in-aid, loans on favorable terms, and other benefits in exchange for meeting reform targets.

The EA 2003 reiterates several policy areas that have been included in the MOUs between State and Central governments. Clauses 131-134 and 172 provide general guidelines for *restructuring of SEBs*, including vesting of assets in state governments,

provisions for sale of parts of the Board to private companies, and division of the SEBS into separate generation, transmission, and distribution companies. The Act also reinforces the requirements that have been written into the MOUs between State and Central governments by *mandating that all states form State Electricity Regulatory Commissions*. (Clause 82). The act also requires that subsidies be paid out of State government budgets (Clause 65). The act requires *universal metering* (Clause 55), again underscoring the kinds of changes agreed to in the MOUs.

The Electricity Act of 2003 also permits state governments to set up special courts (Clause 153) to provide quick trials in cases of theft. *Punishments for theft* include up to three years of imprisonment as well as fines. (Clauses 135-50). The red tape involved in setting up these courts, however, dulls the impact of this provision. Delhi, for example, has been attempting to set up two special courts to try cases of power theft for nearly two years – and as of September 2004, these were still not in place. Godbole (2004) also reports that the police have been slow to help Delhi’s private distribution companies identify theft cases. The fact that some arrests and punishments have occurred, however, marks progress.³¹

The EA 2003 also adds two additional incentives for improvement in the distribution sector: competition in distribution, and institutions for empowering consumers Existing distribution companies are free to undertake generation, while generation companies could also engage in distribution (Clauses 7,12). *Multiple distribution licenses* may be issued for any particular area. Open access in distribution will be phased in as soon as arrangements for cross-subsidy and universal access surcharges can be worked out. The provisions for phasing in open access commit the government to at least consider changes in cross subsidization and provisions for universal service.³²

³¹ “End of Scheme to Declare Tampered Power Meters,” *Hindustan Times* December 1, 2004.

³² Legislating that open access should be “phased in” may not be the strongest commitment since there are many ways to delay such changes, but it does provide a foothold for potential investors, industrial consumers, and others who might benefit from reforms.

EA 2003 also creates a forum for consumer monitoring of service quality by mandating that distribution licensees set up a forum for addressing consumer complaints in accordance with guidelines to be specified by the state regulatory commissions. Each SERC must appoint an ombudsman to hear complaints that are not redressed by the distribution licensees. Regulators are explicitly prohibited from setting tariffs that discriminate among consumers of electricity except on technical grounds such as load factor, time and size of consumption, etc. (Clause 62). An appellate tribunal provides an avenue for consumers to protest other regulatory decisions (Clause 111).

Recent outcomes in the electricity sector suggest that these commissions, legal changes, and incentive programs are more than empty gesturing. The foundations for a regulatory framework are being laid, distribution sector reforms appear to be moving ahead, and the cash losses and aggregate technical and commercial losses (ATC) are dropping.

States have taken several steps toward making the distribution sector more viable. Sixteen states have 100% metering of 11Kv feeders, and another 5 have over 90% metered. Only six states have 100% consumer metering, but 12 more have over 90% of consumers metered.³³ According to *Metering International*, (2002, Issue 4), India has emerged as one of the major markets for electronic energy meters and the large-scale development of electronic meters and proactive government policies have encouraged many meter manufacturers to operate in the country.

States are also moving toward more transparent accounting of the cost of subsidies by including compensation to SEBs as an item in the budget. SEBs in Andhra Pradesh, Orissa, Tamil Nadu, Rajasthan, Madhya Pradesh, Gujarat are now being compensated out of state budgets, though the budgeted subsidy payments do not actually cover expenses. The commercial losses of SEBs were Rs 210,517 million in 2003-4, and even after explicit subsidies from state budgets the deficits totalled Rs 100,090 million. The

³³ Bajaj, H.L. (2004). It is unclear just how much of an increase this level of metering represents. These figures are listed here (as well as in Ministry of Power documents and other available sources) as “achievements of APDRP” without reference to what the status was before. Nevertheless, the fact that metering rates are recorded and states are explicitly compared is one sign of progress.

Economic Survey estimates that SEB losses will be Rs 210,698 million before state subsidies, and Rs 100,556 million after subsidies in 2004-5.³⁴ The states' own fiscal position probably prevents them from offering more.

In terms of distribution sector performance, the Ministry of Power website lists the following achievements:³⁵

- Cash loss reduction by Gujarat, Haryana, Rajasthan, Maharashtra and Madhya Pradesh during 2001-02.
- Cash loss reduction by Andhra Pradesh, Assam, Gujarat, Maharashtra, Madhya Pradesh, West Bengal and Uttar Pradesh in 2002-03.
- Increased Average Revenue Realisation (ARR) by Maharashtra, Gujarat, Punjab, Madhya Pradesh, West Bengal, Chattisgarh, Himachal Pradesh, Orissa, Delhi, Manipur and Nagaland
- Aggregate Technical and Commercial (AT&C) loss reduction by Maharashtra, Gujarat, Uttar Pradesh, Punjab, Madhya Pradesh, Uttaranchal, Assam and Delhi.

At least some of these changes have been attributed to the incentives created by unbundling of the generation, transmission, and distribution segments.³⁶

Management changes are also underway. Gujarat and Karnataka have handed over parts of the distribution sector on management contracts to franchises and Jharkand appears to be moving in this direction. Maharashtra, Uttar Pradesh, Gujarat and Rajasthan are in discussions with Tata Power Company to involve them in improving distribution infrastructure.³⁷ State ERCs have also begun to penalize excessive transmission and distribution losses by reducing normative loss levels for the purpose of calculating tariffs.

These are clearly steps forward, but on a very long road.

First, incentive funds such as those used to motivate the distribution sector reforms have several potential pitfalls. Performance indicators must be chosen carefully to ensure that

³⁴ Figures cited in Swaminathan, S. Anklesaria Aiyar. (2004). "Power, India's Achilles Heel," in Times of India 9/19/04.

³⁵ http://powermin.nic.in/apdrp_page.htm, accessed on Nov. 18, 2004.

³⁶ Prayas (2004a).

³⁷ "Tata Power in Expansion Mode," *Project Monitor*. October 16-21, 2004. Online at <http://www.projectsmonitor.com/detailnews.asp?newsid=8309>

states are not manipulating accounts to meet the monitored goals while sacrificing longer-term performance. Prayas (2004b), for example, points out that utilities for which service quality is not monitored might avoid making investments and thus record large profits that *look* like improved performance but sacrifice long-term service quality. While the citizen complaints enabled under the Electricity Act 2003 could provide some warnings of lower service quality, this may not be strict enough monitoring if the appellate tribunals and ombudsmen are not established quickly or do not have the resources to keep up with cases.

Second, there is a long road ahead in rationalizing cross-subsidization and working out provisions for the distribution of the costs of universal service provision. Improving metering and the technical aspects of billing systems has been seen as the “silver bullet” in distribution sector reform, but, as Tongia (2004) point out, it cannot overcome the effects of cross-subsidization and political unwillingness to impose higher user costs. The costs of cross-subsidization now create also a substantial incumbency disadvantage in distribution, which may increase the drain on public sector distribution companies’ resources.³⁸

The N.K. Singh Task Force on Power Sector Reform’s (TF) suggestions for retail tariffs provide some indication of the direction the government is moving in. Given the wide discrepancy between cost of service and consumer tariffs, the task force report focuses on tariff formation based on revenue allowances rather than the tariff ceilings used in more advanced markets. The TF’s recommendations for revenue allowances are more precise and focused on clarifying, if not improving, distribution companies’ accounts. Working capital should be allowed, and outstanding receivables (i.e. past-due accounts) should be recognized and provisioned for. The TF recommends that tariff and dividend control reserves not be allowed as part of the revenue requirement. It seeks to reduce time shifting of liabilities by recommending that “regulatory asset” should be used sparingly

³⁸ All distribution licensees are bound by a Universal Service Obligation (USO) to serve all classes of customers on request, but this may affect incumbents more than newcomers unless distribution licensing areas are carefully defined to include equal customer mixes.

and for limited time periods only. Finally, the TF seeks further clarification of costs of distribution by recommending accounting separation between distribution and supply.

In general the TF seeks to shift incentives toward rewarding distributors for improved performance rather than mistakes already made. For example, it sets limits for application of fixed charges in cases where distribution licensees' assets are stranded – leaving it up to the licensee to demonstrate that the risk could not have been mitigated through pricing. The TF recommends that the surplus from improved efficiency would go mainly to the distribution companies during the first control period (recommended as somewhere between 3-5 years). Later tariff periods would involve more savings passed on to the consumer.

The TF's proposal for working out the distribution of costs for universal service provision is to award licenses to roughly equal groups of consumers but impose a cross-subsidy surcharge based on the difference between actual tariffs and the long run incremental cost (LRIC) to ensure utilities are compensated fairly for fulfilling the USO.³⁹ Calculating the LRIC, however, imposes substantial information requirements, since it is based on integrated resource planning of the future trajectory of distribution and other costs.

These kinds of steps need to continue. Achieving financial viability in the distribution sector, which translates in most cases to the financial viability of the State Electricity Boards, would be a strong signal to investors and others that the electricity sector reforms, and the promise of profits gained from supplying India's unmet demand for electricity, are credible.

5. A NEW MARKET MODEL

³⁹ The TF recommends that the minimum boundaries of a distribution licensing area be a revenue district or a municipal corporation for a larger urban area and a municipal council for a smaller urban area.

The Electricity Act 2003 “seeks to bring about a qualitative transformation of the energy sector through a new paradigm.”⁴⁰ We highlight four aspects of this new paradigm: that it includes the private sector far more extensively than before; that it moves away from the single-buyer model (and, at least for now, toward competitive wholesale power markets); that it includes stronger performance incentives (both market-based and regulatory) in tariffs; and that it envisions a stronger role for the central government in coordination of power sector policies.

The new paradigm, however, needs a foundation built on a healthy distribution sector, increased physical capacity, particularly in transmission, and stronger regulatory institutions. Section Six calls for more progress on these fronts.

The New Paradigm

The Private Sector

The act *eases requirements for private entry into generation*. It reduces licensing requirements for generation, except hydropower (which still needs clearance from the Central Electricity Authority as it uses the state’s resources). It also *opens transmission and distribution to private participation*, though participants still require licenses (Clause 14).⁴¹ The Act envisions that Central and State-level transmission utilities will be government companies with the public sector responsible for planning and coordinating development of the network. The policy creates only a distant threat of competition for existing transmission networks, however, as the cost of building parallel networks is high enough that only the least reliable and least well-maintained networks would be at any risk of being replaced by parallel networks.

⁴⁰ Summary and complete EA 2003 text available at <http://powermin.nic.in/note2003.htm>

⁴¹ Private participation in operating and maintaining transmission networks had been allowed previously, but EA 2003 allows private companies to potentially set up parallel transmission networks or develop new links.

Captive generation is freely permitted, as are dedicated transmission lines (Clauses 7,8,9). Captive power plants are also exempted from surcharges for access to the grid. The act encourages creation of non-profit societies, user associations, and other arrangements in rural areas – these will be allowed to buy bulk power and bypass SEBs. (Clause 4,5). This easing of restrictions on rural cooperatives is likely to contribute to greater penetration of electricity service in rural areas.

The new provisions for captive power plants, in particular, place pressures for reform on the public sector since they ease the barriers for industrial users to opt out of the public system – thereby limiting the extent of cross-subsidization that can take place. The liberal definition of “captive power plants” also makes it possible for generating plants to avoid paying the cross-subsidy surcharge for open access by declaring themselves captive power plants.

The provisions for private participation are one of the less contentious areas of the reform (at least among policymakers, if not unions). The recently elected UPA government’s Common Minimum Plan “reiterates [its] commitment to an increased role for private generation of power and, more importantly, power distribution.”

Moving Away from Single Buyer Model

The Electricity Act contains two provisions leading toward a market where multiple buyers, suppliers, and middlemen are possible. It requires that all *transmission utilities provide non-discriminatory open access* to their system from the outset. (Clauses 38-40), and designates trading and wheeling as separate transmission activities (Clause 12). The Power Trading Company of India had been trading before this provision (since 1999), so the EA acts as more of an impetus for faster expansion of trading than fundamental shift in the market structure. Transmission utilities are barred from trading, but distribution companies will be allowed to trade without separate licenses, and generation companies

can sell to any distribution companies and large-scale users as soon as regulations are developed.

The CERC tariff order for open access pricing became applicable on January 30, 2004. Its provisions for non-discrimination are quite clear. Longer-term consumers (those with contracts of 25 years or greater) have priority over short-term consumers. Short term access requests must be accommodated if capacity is available. There can be no discrimination between SEBs and open access customers, as specified in EA 2003.

The central transmission utility (Power Grid Corporation of India) has been charged with developing the procedure for applying for long term transmission access, while the Regional Load Dispatch Centers are to oversee the bidding process for short-term access. The regulations' basic floor for pricing, in Rs per MW per day, is backward-looking, with short-term rate based on the average transmission charges over the past year divided by average capacity served over the last year. Transmission utilities are expected to announce a rate in Rs per MW per day at the beginning of the year, which remains in effect for a year. Unscheduled interchange (UI) charges also apply for deviations from scheduled injection and drawal of power. If requests for access are higher than capacity, the Regional Load Dispatch Center coordinates bidding.

Transmission customers bear the costs of transmission losses on the basis of average losses in the national transmission system, calculated ex-post based on actual flows. It would be worthwhile to consider changing this regime to one in which transmission companies bear the burden of these losses, as this would create a greater incentive to mitigate losses. The rules for open access do provide some incentive to maintain transmission lines at high capacity, however: transmission licensees can keep a quarter of the charges earned from providing transmission to short-term customers while returning the balance to long-term customers through tariff reductions.

Open access to state transmission lines lags behind. Tariff orders for open access have been coming out in some states, however, and applications for open access have already

begun. Reliance (BSES) applied the Maharashtra Electricity Regulatory Commission for open access on TPC and Maharashtra SEB transmission networks in August 2003.

MERC approved the application in January 2004, directing TPC and MSEB to provide open access subject to availability of spare capacity and the negotiation of an agreement on transmission costs.⁴²

The structure for the power exchange was yet to be determined at the time of writing, but licenses for power trading have already been granted, implying increased competition for the incumbent Power Trading Company.⁴³ Tata Power Company was the first private company to obtain a trading license from the CERC, and was quickly joined by Reliance, Adani Exports, and others. The CERC had issued 11 licenses as of November 2004. PTC has the advantage of accumulated knowledge and existing relationships with buyers and sellers, but a recent (June 2004) report on PTC stock advises that “competition will heat up.”⁴⁴ The scope for trading is still limited, however, as over 95% of electricity generated is sold under long-term PPA agreements.⁴⁵

Subsequent policy discussions have proposed deepening the trading market from the supply side. The N.K. Singh Task Force Report on Power Sector Reforms, for example, recommends that the unallocated share of National Thermal Power Company power be sold through trading arrangements, through separate trading companies rather than just subsidiaries of NTPC. It also suggests that a portion of the output from new generating stations be sold through competitive power markets, and at shorter contracts than typically present for trading today.

Given the general shortages of supply for existing demand patterns, and the low-rainfall monsoon in 2004, however, whatever power sold through the trading system is likely to

⁴² The approval was essentially meaningless, however, as an ERC report found that there was no spare capacity available.

⁴³ Ghosal (2004). “CERC Map for Power Trading Bourse,” *The Telegraph* November 30, 2004 reports that the CERC will appoint a consultant in the next two months to design a power exchange along the lines of those in the US and Europe.

⁴⁴ Raghuvir Srinivasan (2004), “Power Trading Company: Buy,” in *Hindu Business Line* June 27, 2004. Online edition.

⁴⁵ The prospect of higher trading prices for power may increase generation, of course.

find a willing buyer. Delhi, for example, is not expected to have adequate capacity for winter 2005 and has not been able to obtain a reliable supply from contracts with trading companies. This is in part due to low rainfall during the last monsoon that limits hydro plants' capacities.⁴⁶

Tariffs

The recent wave of reform involves two major changes in tariff policy. The first, Availability Based Tariff, was introduced for bulk power purchases from central public sector utilities by the CERC under the Indian Electricity Grid Code in 1999 and implemented for all regional and inter-state bulk power purchases by 2004.⁴⁷ The three-part tariff, consisting of a fixed capacity charge, a variable charge based on power consumed (rather than power allocated as in the existing tariff regulations), and an unscheduled interchange (UI) charge based on deviations from scheduled generation and drawal of electricity from the grid, has increased grid discipline.⁴⁸ ABT has not been implemented for state transmission lines, however, limiting overall effect on grid discipline.

The second, a call for a *tariff framework based on competitive bidding* to form the basis for generation, transmission, distribution, and retail supply for electricity was introduced by EA 2003 (Clause 63). The Act leaves the details up to the national government (Clause 3(1)), the CERC and state ERCs (Clause 61 and 62). The Act requires that tariffs be set to “encourage competition, efficiency, economical use of resources, good performance, and optimum investments” as well as “safeguarding of consumers’ interest and at the same time, recovery of the cost of electricity in a reasonable manner. It provides very little guidance, however, on the details of regulation. The main provisions are that tariffs should be based on multiyear tariff principles to increase the predictability of pricing relative to the 1-year reviews currently used for pricing (Clause 61) and that generation

⁴⁶ “Cold and Powerless in Winter,” *Times of India* November 19, 2004. Online edition.

⁴⁷ Implementation was controversial: several SEBs and NTPC protested

⁴⁸ Prayas (2003a).

and transmission tariffs should be determined on the basis of competitive bidding (Clause 63).

Subsequent tariff notifications have generally followed these principles, though the future is still unclear. The CERC tariff order applicable from April 1, 2004 stated that all future projects in generation, transmission, and distribution would be selected through a tariff-based bidding process. The guidelines for competitive bidding, however, have not been finalized.⁴⁹

The CERC has moved toward a more light-handed regulatory approach in generation and transmission tariffs, with more emphasis on performance than before. The two-part structure is superficially similar to before, with fixed costs based on depreciation, interest on working capital, income taxes, etc. The key difference is that the tariffs provide a ceiling of 14% return on equity, as opposed to a floor of 16% under past regimes. Working capital allowances and operations and maintenance costs, transit and handling losses of coal, and other operating parameters are set at normative rather than actual levels, so that companies can only make this rate of return by performing at relatively high benchmark levels. Like the transmission tariffs mentioned above, generation tariffs provide incentives for plant maintenance by rewarding higher plant load factors.⁵⁰

The new regulations may also be more appealing to potential investors. They reduce incumbent advantage by eliminating the development surcharge that incumbents had been allowed to charge to gather funds for new investments. The CERC also increased the control period to 5 years, as recommended in EA 2003 to provide added regulatory certainty.

⁴⁹ The CERC notified the central government of draft guidelines for procurement of new generation capacity through competitive bidding on October 3, 2004.

⁵⁰ This incentive mechanism may be detrimental to the overall health of the grid unless unscheduled interchange (UI) charges, which included in the CERC regulations but are adjustable at the regulator's discretion, are set high enough to deter over-supply of power. Tongia (2003). See also Pandey (2004) for detailed comparison of the incentive effects of the draft tariff regulations (which were quite similar to those actually adopted) to previous tariff regulations.

The impact of both of these tariff changes on the national electricity market, however, may be limited by the fact that the state ERCs have substantial independence in setting their own tariff orders. Section 86(4) of the Electricity Act 2003 states that, “In discharge of its functions the State Commission shall be guided by the National Electricity Policy, the National Electricity Plan and tariff policy published under section 3.” It does not specify how much this “guidance” should be weighed nor what the penalty for departing from the CERC recommendations would be. The fact that power is a concurrent subject also impedes extension of Availability Based Tariff to intra-state power generation.

State-Center Relations

EA 2003 establishes the *Central government’s leadership* – though not explicit control – in developing a common national energy policy, accounting and regulatory norms, as well as tariff frameworks and arrangements for making subsidies more transparent. Clause 3 empowers the Central Government to prepare a National Electricity Policy in consultation with State Governments, while Part 9 (Clauses 70-75) reiterates the supervising role of the Central Electricity Authority in advising the central government on the National Electricity Policy, specifying technical and safety standards for new projects, specifying grid standards for new transmission lines, carrying out research, and advising all levels of government as well as private licensees. The Act empowers the CERC to set the tariff principles and methodologies to be followed by SERCs.

The EA 2003 provisions relating to the duties of states to move forward with unbundling and reform of cross-subsidization have been some of the more controversial parts of the Act. The timeframes for unbundling and phasing out surcharge have been relaxed by the central government, some by as much as one year, following substantial pressure to review the Act.⁵¹

⁵¹ This review has not taken place as of the time of writing and may never take place. The Minister of Power, P.M. Sayeed, has explicitly precluded such a review.

The Task Force's recommendations for various financial incentives that the central government could provide to the subnational governments would provide an additional degree of central government influence over subnational governments.

6. INVESTMENTS IN SUCCESS

The success of the new market model hinges on India's ability to make substantial physical investments as well as institutional changes now, in addition to the continuation of the distribution reforms discussed in Section Four.

A wholesale market cannot be competitive unless capacity constraints in generation, transmission, and distribution are removed. Given India's current finances, the private sector will need to be involved in financing these investments – but private investment will be difficult to attract until there is a credible reform program in place. Second, a wholesale market cannot be run without substantial and costly software and other technical upgrades to the Indian system.

As Wolak's chapter in this volume argues, expenditures on technical aspects may be pointless without investments in building institutions to govern the power sector. A wholesale market needs strong and independent regulators. India's system of "concurrent responsibility" of state and central government in the electricity sector may lead to some confusion over responsibilities and jurisdictions.

Physical Prerequisites for a Competitive Market

The main priority, for both public and private investment, is to augment transmission and distribution network capacity. Open access is not possible without spare capacity. There is clearly some kind of shortfall in generation relative to demand at current prices, but it is difficult to estimate what the magnitude of the shortfall will be after retail tariffs are adjusted and more consumers are metered.

Investment Needs

Investment in generation will not come without assurance of adequate transmission networks and solvent distributors, but new investment and better maintenance of transmission networks will not come without sufficient demand for services by generators and distributors as well as appropriate pricing or subsidies. Investment in distribution remains unattractive unless consumers are more widely metered and more willing to pay, but consumers will be unwilling to pay unless there is adequate and reliable supply from generators. This is a classic coordination problem – if the government can put together a credible and economically sensible plan for the sector, such a plan can serve as the coordinating device, assuring various segments that the demand for their output will be there.⁵²

In the meantime, investment incentives are a second-best option for attracting investment. The Task Force report recommends two explicit incentives for investment in addition to the more general provisions for improving the investment climate through changes in regulation, etc. The first is a significant reduction of the taxes and duties paid by investors in the power sector, and second, loosening of banking sector restrictions to increase the available supply of funds from both domestic and international sources. The Task Force report also calls for a government role in transition financing while the state-owned electricity utilities restructure, improve collections, and upgrade facilities.

Fiscal Incentives for Investment

The Ministry of Power committed to extending the policy of zero customs duty to selected “mega power projects,” of 1000 MW or above (500 MW for hydro projects) that serve several states to thermal power projects of 250 MW and above and all hydel but this had not yet been implemented at the time of writing.

⁵² EA 2003 has attracted some investment, of course: private companies such as Reliance Energy and Tata Power have laid down large capital expenditure plans of around Rs 200 Billion and Rs 120 billion, respectively, over the next five years.

Implementation of some fiscal incentives has slowed under the current UPA government relative to the plans of the previous NDA government.⁵³ Customs duty on equipment for high voltage transmission projects was reduced from 25 percent to 5 percent in the 2003-4 budget. Basic customs duties on other power transmission and distribution projects were reduced from 25% to 10% in the interim 2004-5 budget, but these were not implemented by the current government. The 2004-5 interim budget also proposed a reduction of customs duty on electricity meters from 25% to 15% and a reduction of customs duty on coal from 25% to 15%, but this has also not been implemented.⁵⁴

The current government's 2004-5 budget does, however, offer a tax exemption for new power sector projects undertaken between April 1, 2004 and March 31, 2006. This exemption is less than what the previous government had proposed. While the interim 2004-5 budget extended fiscal benefits (including 100% tax deduction for profits from new power generators) to 2012, the actual budget leaves 2006 as the last year the incentives will be applicable. The new government's 2004-5 budget also limits these benefits to new investors, rather than including companies that take part of State Electricity Boards' assets.

The Task Force Report includes additional fiscal incentives under discussion.

- Exemption from dividend/distribution tax for companies engaged in generation, transmission, or distribution as well as infrastructure capital companies with investments in the power sector.
- Reduction and harmonization of state-level taxes and duties, including stamp duties

⁵³ Information about the current government's fiscal incentives in this section is taken from Mathur (2004) and is current as of August 2004.

⁵⁴ The TF report had recommended that these duties be reduced to 5%.

- Extend exemption from capital gains taxes on long-term capital assets to reinvestments in bonds or equity shares of all power companies or re-investment in power companies on the secondary market.⁵⁵
- Income tax deductions for investments made in government agencies involved in electricity provision
- That states refrain from imposing duties on captive generation (just as GoI has reduced duties on generation in central sector).
- Tax deductions for payments actually made for electricity (to encourage customers to pay)

In some ways, these are the new and improved successors to the guarantees offered to investors in the first wave of reforms. The tax breaks apply to all potential investors, rather than the select few who received guarantees under the previous policy. Both guarantees and tax breaks amount to a subsidy to investors, but the surplus is more evenly divided with the latter. With guarantees, the government bears the entire downside risk and faces the possibility of large shocks to its budget plans – meaning unexpected contributions to deficits – if some part of the investment environment fails. In the case of the 1991 Central Government guarantees, the central government was actually betting on SEB payment performance, a factor that it had little direct control over. The tax reductions, on the other hand, are likely to have less of a budgetary impact: the lower taxes will increase overall economic activity in the sector, meaning a larger pie even if the government has a smaller share. Tax reductions are also a less costly way of administering subsidies, as they are forgoing collection rather than incurring the costs of collection and then returning money.

The fiscal incentives may also contribute to more nuanced policy goals than guarantees. The last tax deduction for payments actually made to electricity relieves the burden of the few who actually pay, potentially reducing their incentive to opt out of government electricity provision and rely on captive generation. The tax deduction might also lower

⁵⁵ Investors already have the option of avoiding capital gains by reinvesting capital gains in certain government development banks.

the level (and costs) of enforcement needed to obtain more widespread payment for electricity tariffs. Consumers weighing the costs (monetary) and benefits (reducing fines) of paying face lower costs and thus require either smaller fines or lower probability of enforcement to sway them toward payment.

The approach also has the advantage of improving the overall investment environment and providing an example for other sectors trying to attract private participation, though care has to be taken in minimizing complexity and opportunities for fraud.

The potential drawback of fiscal incentives is that these kinds of provisions may not have much power to attract investment. Tax policies are not per se credible policies, as the government may change the tax regime once investment is sunk. This is unlikely to happen in India since Parliamentary approval would be needed to alter the tax benefits and no benign tax policy has ever been retracted, but still a possibility. A contract between Nandi Infrastructure Corridor Enterprise and the government of Karnataka state for the construction of the Bangalore Mysore Infrastructure Corridor, for example, waived stamp duty, but this policy was changed in 2003 when the state government reduced stamp duties across the board and discontinued the waivers that had been used in the past. The project was delayed as the promoter and the government wrangled over payment of the new, lower, stamp tax.⁵⁶ Such examples of either sudden fiscal changes or alteration of contractual obligations entered between the parties are likely to decrease the credibility of fiscal and other promises.

Also, while tax changes may affect the relative attractiveness of investments within India, there is no guarantee that investments in Indian electricity infrastructure will be attractive relative to international opportunities. In a world where capital is increasingly globalized, this is an important perspective to keep in mind.

Financial Incentives for Investment

⁵⁶ This is not to say that the BMIC is a model infrastructure project. There have been substantial questions in the press regarding the terms of the initial contract as well as subsequent project management.

In the interest of obtaining a greater flow of funds to the electricity sector, 100% foreign equity in hydro-electric, coal/lignite based, and oil/gas based thermal power plants is now automatically approved.

Other measures for increasing the flow of funds from domestic investors are under discussion. The Task Force also makes various recommendations for modification of the banking sector regulation to encourage banks to lend long-term to the energy sector:

- Relax exposure norms (RBI/IRDA as well as internal sector exposure limits) pertaining to companies or groups for investment in the power sector, provided the companies/ groups have an appropriate credit rating.⁵⁷
- Bonds with an appropriate credit issued by utilities/ private power sector companies or banks and institutions with an interest in the power sector be included on the list of securities that can be held to satisfy statutory liquidity ratios (SLR).
- Review and potentially raise cap on interest rates for external commercial borrowings to allow sufficient margins over LIBOR to attract investors.
- Review and potentially lift ban on domestic guarantees extended to foreign investors.
- Designation of rural electrification and transmission and distribution sectors as “priority sectors” for bank lending.⁵⁸
- Encourage innovative long-term financing by banks, such as “takeout financing” with institutions like PEC, REC, Infrastructure Development Finance Company (IDFC) as the takeout lenders.⁵⁹

⁵⁷ The provision to increase allowable exposure to particular companies favors existing generating facilities over newcomers, by increasing the amount of investment that can be directed toward expansion rather than new entrants. This is not necessarily a problem, however, if the regulators are strong enough to prevent market power in a concentrated generation sector.

⁵⁸ Commercial banks are currently required to invest 40% of aggregate bank advances in designated priority sectors such as agriculture, small scale industries, etc.

⁵⁹ With “takeout financing,” the “takeout lender” makes a long-term loan for financing an infrastructure project, then repackages this loan as participation certificates to assume part of the loan for a specified time period. Banks can then participate in the loan for a defined period with a given risk profile, while the

- Review current proposal to cap banks' issuance of long-term bonds.

The relaxation of exposure norms, lifting of caps on interest rates for ECBs, lifting of bans on domestic guarantees to foreigners, encouragement of innovative financing, and lifting of caps on banks' issuance of long-term bonds might be viewed as removing distortionary impediments to the free functioning of the capital market. The call to "review" policies before implementing changes, however, must be taken seriously. All of these provisions potentially expose the banking sector to significant risk, particularly if the more substantive regulatory environment does not improve. There is a fine line between encouraging banks (especially public sector institutions charged with infrastructure finance) to leverage their resources toward achieving social goals of better infrastructure, and eroding risk management.

The provisions allowing the banks to hold bonds from energy sector companies as part of SLR and awarding the energy sector priority sector status are potentially more dangerous for the financial sector than relaxation of exposure norms. Banks' project reviews and oversight may not be as rigorous for this group of holdings. It is possibly that the favor shown to energy sector investments would also be taken as an implicit government guarantee.

The clause restricting such investments to "those with an appropriate credit rating" also requires clarification. Where do the credit ratings come from? Is the credit rating relevant for regulation before or after the investment in the energy sector? Finally, how many companies are there with an "appropriate credit rating" that involved in energy sector?

Transition Financing

Transition finance includes investment in distribution, incentive grants and loans to motivate state-level reforms, and provision of funds to meet transitional working capital

borrower has the advantage of longer-term financing. This has been used by the Indian Development Finance Company (IDFC) in the late 1990s.

and investment resources while transmission & distribution losses and other inefficiencies are being reduced. Most importantly (from a political economy perspective) transition financing fills the gap between the actual tariff increase in the short term and the tariff that would be justified based on costs of providing service.

Transition financing raises two challenges: first, how to design the conditionalities, and second, how to ensure that the financing itself creates incentives to make progress through the transition.

The current policy discussion includes a few options. Loans are mostly via government entities such as the Infrastructure Development Finance Commission, the Power Finance Corporation, Rural Electrification Corporation and come linked with reform conditionalities. The recently announced Industrial Infrastructure Fund makes additional funds available at low interest rates for urban infrastructure projects including electricity. The TF also recommends redirecting APDRP funds for transition financing and reducing the loan rates charged to market levels from the current 12%.

The main way of increasing the quantum of funds available is to retract commitments for projects that have not yet begun and use these funds for transition financing. The TF report acknowledges that these funds may not be sufficient, and that states may have to seek additional market financing or multilateral assistance. Market and multilateral financing is likely to reward the same factors as the central government does under the APDRP program, leading to a disproportionate share of resources for good performers and less transition financing for laggards.

The speed and success of transition, however, is ultimately a question of the design of India's federal system. One ongoing challenge will be to balance the need to set up safety nets to ensure that all citizens have some level of access of electricity without compromising the strength to incentives for other states to move forward with reforms. The central government currently has more carrots than sticks in promoting reforms and has little power to sway states that simply do not meet reform milestones.

Technological and Procedural Prerequisites for Market Operation

As discussed in Wolak's chapter, the Indian electricity grid needs additional technology to run the bid-based spot market envisioned. Real-time metering throughout the transmission grid (both in central government regulated inter-state transmission as well as state-regulated intra state transmission) would be need to ensure that participants honored their spot market obligations. Settlement software to collect from electricity users and pay generators would have to be adapted for the Indian market. Market-making software would have to be developed, in addition to a means for all market participants to communicate with the systems operator.⁶⁰ Wolak cites a start-up cost for the California spot market of \$250 million.

This stage is several steps away, however. Many of the technical details of developing a national power market are also not specified in the Electricity Act of 2003. It does not, for example, give details on Independent System Operators, for example. It envisions a national load dispatch center (LDC) (Clause 26) but leaves its constitution and functions to be prescribed by the central government. EA 2003 reiterates the role of regional load dispatch centers in inter-state transmission and of state load dispatch centers in intra-state transmission, but does not specify how the two (or 3) LDCs will communicate.

Developing procedures for operating the network is an exercise in state-central government coordination and policy dialogue. Aside from the raw infrastructure planning, grid management policies also depend on state-central government coordination. The recommended process for reviewing the scheduling system, for example, consists of 1) having regional load dispatch centers review facilities, 2) report the findings to the CERC, and 3) the CERC reviews and forwards to the SERCs "for further action." (30). EA 2003 requires states to form independent system operators (State Load Dispatch Centers), but these have not yet been put into place in all regions.

⁶⁰ See also World Bank (2001).

The Task Force Report reflects this reality, in that its recommendations for improving the network are mostly assignment of responsibilities:

- The central government develop should overall power market guidelines within one year
- Central and state transmission utilities should develop/modify/clarify grid code, balancing code, and settlement code, within three months. The most recent Grid Code dates to March 2002.
- Central transmission utilities should develop specifications for settlement systems within three months.
- Functional and accounting separation of system operation from transmission within four months, organizational separate after power market guidelines are developed
- The metering and communications infrastructure for extending Availability Based Tariff (ABT) to states should be implemented as soon as possible (a recommendation echoed by the recent CERC tariff regulations).

Institutional Prerequisites for a Competitive Market

Meeting the institutional prerequisites for a competitive market runs a close second to distribution sector reform in its importance for the successful reform of the power sector. EA 2003 requires advance approval for sales, mergers, takeovers of entities within the same state, and states that no licenses would be exclusive within a region. These provisions may limit monopoly powers, though much will still depend on the degree of contestability and development of regulation to prevent abuse of market power.

The basic regulatory framework of a Central Electricity Regulatory Commission and State Electricity Regulatory Commissions exists, but these bodies must be made more independent, staffed with more skilled people, and provided with the data necessary to identify and punish market power. The division of regulatory and other responsibilities between the state and central governments must also be sorted out – the Electricity Act

2003 is a start, but far from a clear and transparent division of policy authority. We acknowledge the costs of decentralized policymaking – which seem to be driving the trend toward greater centralization of authority – but argue that decentralized governance of the electricity sector has some unique advantages during the reform period.

Independent, Skilled, Knowledgeable Regulators

The CERC, established under the Electricity Act of 1998, has played an increasingly active role in regulating the power sector. It is largely on schedule with the various tariff notifications, bidding guidelines, licensing requirements, and other aspects of regulation that the Electricity Act 2003 assigned to it. It is difficult to discern the degree of independence. The weight given to other arms of the central government in formulating the general tariff policy could be seen as a sign of the lack of regulatory independence.⁶¹

As of November 2004, 22 states have constituted SERCs and two more have notified the constitution of a regulatory commission. Seventeen of these have issued tariff orders.

These have varying degrees of independence from the state governments. One indicator of their degree of political insulation, their ability to impose or increase tariffs for agricultural connections, demonstrates this variation. All states had imposed some kind of user charges for agriculture as of February 2004⁶², Andhra Pradesh and Tamil Nadu, two states that have SERCs, reversed this policy after the elections in spring 2004, as did Maharashtra's incumbent government just before the October 2004 elections.⁶³ Several members of state regulatory commissions note that state government-owned utilities also do not always comply with the commissions' recommendations and offer "all kinds of excuses" when pressed.⁶⁴ Godbole (2002) documents several cases in which the "hidden hand of state government" helped determine revenue requirements, calculating

⁶¹ Pandey (2004).

⁶² According to MOP (2004).

⁶³ Maharashtra state government has also imposed a new sales tax, on power consumed by industrial and commercial consumers. This tax, retroactively effective from April 2004, further increases the gap between industrial and other users' prices. Damle, Manjiri (2004). "After Free Power, It's Payback Time," *Times of India*, November 19, 2004. Online edition.

⁶⁴ Balasubramanian (2003), Gupta (2003). Quote is from Balasubramanian.

transmission and distribution losses, and setting tariff increases (which were lower than initially recommended), though it is hard to tell how widespread this influence is from a few damning anecdotes. More recently, state level regulators are also cited as having pointed out that “political interference and lack of support from state governments hindered their performance and efficacy.”⁶⁵

The prescriptions for building regulatory independence are fairly straightforward: ensure an independent revenue base, a merit-based selection process, and security of job tenure even as elected officials turn over. The political incentives to make these moves, however, are not as simple. When would elected policymakers delegate responsibility to make decisions with important social (and hence political) consequences? The large political economy literature on delegation suggests that delegation is more likely when elected politicians want to avoid difficult decisions, when they are divided amongst themselves and wish to avoid delaying the inevitable by appointing a referee, or when policymakers see the gains from cooperating, but cannot commit by themselves to not act in their individual interests.

Some of these political conditions are present in India. First, rebalancing tariffs is one of the more politically difficult decisions that can be made. An elected official that raises tariffs for agricultural use, for example, is unlikely to be reelected unless he can deliver sufficiently improved quality of service – and achieving the latter may either take too long or be out of his control. The “independent regulator” might be a convenient scapegoat if the blame for giving the independence can be avoided. Second, the competition for foreign direct investment and the increased budgetary pressure created by explicit subsidization of SEBs have increased the gains from cooperating and improving the quality and pricing of electricity supply.

Regulators must be knowledgeable in addition to independent. Data on actual operating costs, operating parameters, market cost of power, and other aspects of utilities’ function

⁶⁵ “Regulators Assured of Autonomy in the Power Sector,” *Business Standard*. Wednesday, November 24, 2004. Online edition.

is necessary to set reasonable normative parameters in tariff regulations. In some cases, even the most basic data is not available: the Maharashtra ERC, for example, computed cross-subsidy surcharge based on average realization and average tariff to the high-tech industry for the SEB, but noted that this information was not available for other distribution licensees in the state.⁶⁶ Some ability to monitor service quality is essential, as mentioned before, to prevent rewards for greater profitability from becoming rewards for sacrificing service quality. Data are not currently organized to make costs at each link transparent – one priority would be set norms for making this kind of disaggregated accounting easier.⁶⁷

Finally, regulators must have the training and expertise to develop, implement, and enforce economically rational policies on tariffs, subsidies, and power trading rules. Staffing is complicated, however, by the requirement of non-market salary structures and other restrictions on employment after completion of their regulatory responsibilities. The result is that these bodies are made up of senior civil servants or people who have served on SEBs in the past. This may have the advantage of continuity, but it prevents injection of fresh talent familiar with contemporary market experience or the evolving academic/technical literature.⁶⁸ The challenge of both human resource development and professionalization of the management of regulatory bodies must receive high priority.

State-Center Relations

The current division of regulatory power between the center and states has both costs as well as potential benefits. The difficulties in coordination of everything from investment to pricing to grid standards appear to be driving the move toward greater centralization of authority. The coordination difficulties are perhaps most severe in transmission. While the central transmission utility (CTU) plans expansion and maintenance of inter-state grids, whatever power carried along these lines generally has to pass over state-run

⁶⁶ Prayas (2004c)

⁶⁷ Tongia (2003) presents one disaggregation and compares costs under different scenarios of efficiency gains in each link. He emphasizes the difficulty of disaggregating even this far with available data.

⁶⁸ It also does little to distinguish the new regulators from the government bodies that used to run the utilities.

transmission grids.⁶⁹ The TF report argues that it is “advisable” that CTU formulates its overall approach first and state TUs use this as a basis for planning, but there is no guarantee.⁷⁰ Similarly, pricing of “transmission service” often involves regulatory oversight from several jurisdictions. In the past, this has led to “pancaking,” or accumulation of charges from transmission across systems in different jurisdictions.

Decentralized decisionmaking has several advantages, however, that are particularly salient while the power sector is in transition. First, states’ ability to determine the details of pricing, siting, and other aspects of regulation creates room for them to compete for foreign investment. While this competition could produce a damaging “race to the bottom” if state offer large concessions such as easy-to-meet normative parameters or loose environmental reviews, it could also motivate states to support independent, skilled regulators. As long as the central government can commit to not bail out the states will additional transfers, the latter effect will be more likely since states’ ability and motivation to offer large concessions to attract what would turn out to be very expensive generation capacity is constrained by the size of their deficits.

Second, states’ ability to choose how and when to unbundle, restructure, and/or privatize SEBs creates a learning opportunity. The state level reforms in Orissa and Delhi discussed in Section Three may not have been as successful as was hoped, but they continue to provide lessons for other states. These states’ experiences with privatizing distribution, for example, may have been one factor in Gujarat’s decision to work with management contracts in the distribution sector rather than sale of assets. The country is also varies on economic, geographic, and social dimensions, and any attempt to impose a “one size fits all solution” may be a waste of resources.

7. CONCLUSION

⁶⁹ The main regional networks have been constructed as per the planning criteria evolved by the CEA, but (as per section 39 of the EA 2003) the planning of the state networks is vested in the STU.

⁷⁰ The TF recommends using the APDRP to motivate states to improve transmission networks.

Electricity sector reforms in India are an ongoing process. The state-level reforms catalyzed by the financial incentives provided by the APDRP and the commitments set out in the state-central government Memorandum of Understanding are yet to be completed. Restructuring of SEBs is underway across the country, and most states have constituted independent regulatory commissions, but these are recent innovations and are still evolving.

EA 2003 sets out a long-term path for creating a competitive market structure, most aspects of which are still being developed. Tariff guidelines, competitive bidding rules, and other crucial aspects of the institutional and legal infrastructure for competitive power markets are subject to debates between the central and state governments as well as central and state regulators. The Central Electricity Regulatory Commission (CERC) and the central government, especially the Ministry of Power and the CEA, have yet to fine-tune their jurisdictions. The process of formulating the National Electricity Policy and other rules has been inclusive for the most part: commissions, task forces, regulators, and others have provided ample opportunities for stakeholders to comment. Such a consensus-based process takes time, however. Many of the early steps to be taken, such as phasing out surcharges, are also generally contentious, adding scope for delay while compromises and transition plans are worked out.

This paper emphasizes the priorities among the wide array of changes being proposed for India's energy sector. We argue that continued distribution sector reform is important in more ways than one. A solvent and well-run distribution sector not only helps attract investment in generation and transmission services by ensuring a reasonable demand for electricity, but it also sends a powerful signal of commitment to reforms. Distribution sector reform may also contribute to customer satisfaction, particularly if the retail companies are responsive to complaints, that could offset the inevitable dissatisfaction with tariff increases. Second, expanding transmission capacity is probably the single biggest priority for use of public funds. This will be essential for implementing open access. Third, India would do well to empower and enable independent regulators at all

levels of government. A leap to a complex market model carries many risks, but these can be lessened with attention to the prerequisites discussed here.

Going forward, there are several questions that we must consider.

How to attract investment in the short term?

Distribution sector solvency, no matter how much it is advocated, will not come about overnight, nor will the credibility of regulation be instantaneous. How can India attract investment in the meantime?

Fiscal incentives, including reduction of import duties and extension of tax benefits, have been used in the past and may be expanded. Financial sector policies to free up domestic capital for longer-term investment are also under consideration, but these must strike a balance between making capital available and limiting potential for imprudent risk-taking. What are other policies to attract investment during the transition period to competitive markets?

What is an appropriate implementation time frame and sequencing of tariff reforms, restructuring, and regulatory changes?

Given the sweeping policy changes envisioned in EA 2003 and subsequent discussions, what should be first priorities, medium term goals, and longer-term goals? For example, if the aim is to reduce the gap between actual and recovered costs of power, should India focus on improving the state of cost recovery (via universal metering, rationalization of subsidies, etc.) or lowering the cost of energy produced (via changing fuel mix, incentives for efficient production, etc) first? What policies have positive externalities that may be harnessed for future evolution of the electricity sector? What aspects of reforms are preconditions for others?

What are applicable “best practices” for implementing provisions of EA 2003 such as tariffs, competitive bidding, open access, metering, and grid management?

The development of competitive markets requires new legal, regulatory, and fiscal frameworks. What are international best practices for these?

EA 2003’s main provisions are that tariffs should be based on multiyear tariff principles to increase the predictability of pricing relative to the 1-year reviews currently used for pricing (Clause 61) and that generation and transmission tariffs should be determined on the basis of competitive bidding (Clause 63). Within this framework, how can tariffs be set to encourage investment and upgrading of existing facilities, as well as more efficient management to lower costs of supply?

There are also technical aspects to be worked out. The Act mandates universal metering, for example, but actually installing and maintaining the hardware will be a long process, as will implementation of energy audits and other mechanisms for managing power distribution.

It may be worthwhile to form a commission to review the experiences of other developed and developing countries in electricity sector reform.

What are possible models for restructuring central and state government-owned utilities?

What are the advantages and disadvantages of privatization versus restructuring under public ownership? Are there ways to break up large public utilities to create competition in the short term? How can India augment human capital for management of new technologies?

We must be creative in developing models for utilizing the substantial labor force already in the government-owned electricity sector more efficiently.

How can the Government of India balance social commitments to keep power affordable, while encouraging an efficient power sector and minimizing drain on budgets?

What are the most efficient ways of administering subsidies? Should it focus on distribution subsidies exclusively, or should subsidy programs be integrated with more complex policy initiatives to improve performance in transmission or generation? How can India begin to untangle the current system of cross-subsidization to make room for competition in distribution without allowing new investors to “cherry-pick” the best customers?

The fiscal pressures created by the growing deficit as well as the social need for improved electricity infrastructure can only be balanced with more efficient spending, of which working out subsidies is a large component.

What is the most effective governance structure for the electricity sector in a federal democracy?

The role of regulator versus the government is still evolving at both central and state levels. What is the best way to insulate regulators from political interference, while ensuring some democratic oversight and maintaining a commitment to social goals such as increasing access to electricity, lowering prices, and other benefits? What are ways to improve coordination between central and state level regulators and system operators? What is an appropriate balance between allowing subnational variation in regulation to suit local preferences, and maintaining a coherent national electricity sector?

This is one topic to be considered by the Commission on Center-State relations proposed in the Common Minimum Programme.

What other areas of reform would contribute to lower electricity costs?

Coal sector reforms, especially reduction of import duties and increased incentives for efficient production and transport would lower the cost of fuel and the price of electricity. What are the first steps to be taken in this sector? Are there other related areas that the government of India should focus on?

What are political measures to ensure that reforms continue to move forward?

Electricity sector reforms at the central and state level have gathered substantial momentum over the past few years. How can India prevent policies such as rationalization of agricultural pricing, implementation of metering, formation of independent regulatory commissions, and others from being reversed? What are vehicles to facilitate further cooperation between state and central governments? What are the key areas of consensus among those in the ruling coalition and what are areas on which consensus could be built? Most importantly, what are strategies for building a consensus among the Indian people?

Electricity reforms will almost surely entail short term adjustment costs, but will definitely benefit all in the medium term through higher growth as well as more direct gains from having reliable, reasonably priced electricity supply. This potential should be recognized and publicized.

There are numerous other open questions that were beyond the scope of this paper, but nevertheless, should be considered in some way. For example, what can India do to lessen the environmental impact of its growing energy consumption? Steps have been taken: EA 2003 specifies that SERCs should set a certain requirement for distribution companies to purchase a certain amount of power from renewable sources, while the National Electricity Policy says that this percentage should be made available from April 1, 2005. The government has also allocated Rs. 200 million in its 2003-4 budget to the Council for Scientific and Industrial Research for research in solar energy, wind turbines, and hydrogen fuels. What else should be done? This is no small economic issue in the long term, given the inevitability of rising oil costs as well as the costs of environmental

damage due to coal use. Again, distribution sector reform might be a good first step toward this end, as rationalizing consumer prices would encourage demand side management. The under-pricing of electricity for agricultural use, for example, creates incentives for more widespread pumping of groundwater, leading to a significant decline in the water table in many areas.

Second, what can the country do to reduce fuel costs? Coal sector reform is an obvious answer, since coal supplies roughly 35% of the country's total primary energy needs and is artificially expensive due to import duties and inefficient coal mining and transport within India. What else can the country do to encourage an optimal mix of fuels?

Fourth, the issue of rural electrification has not been as present in discussions of the move to a new paradigm for electricity provision. Much of this paper has been focused on the priorities in setting up national power markets, but the government's ability to fill in where markets will not go will also be necessary for the sustainability of the reforms.

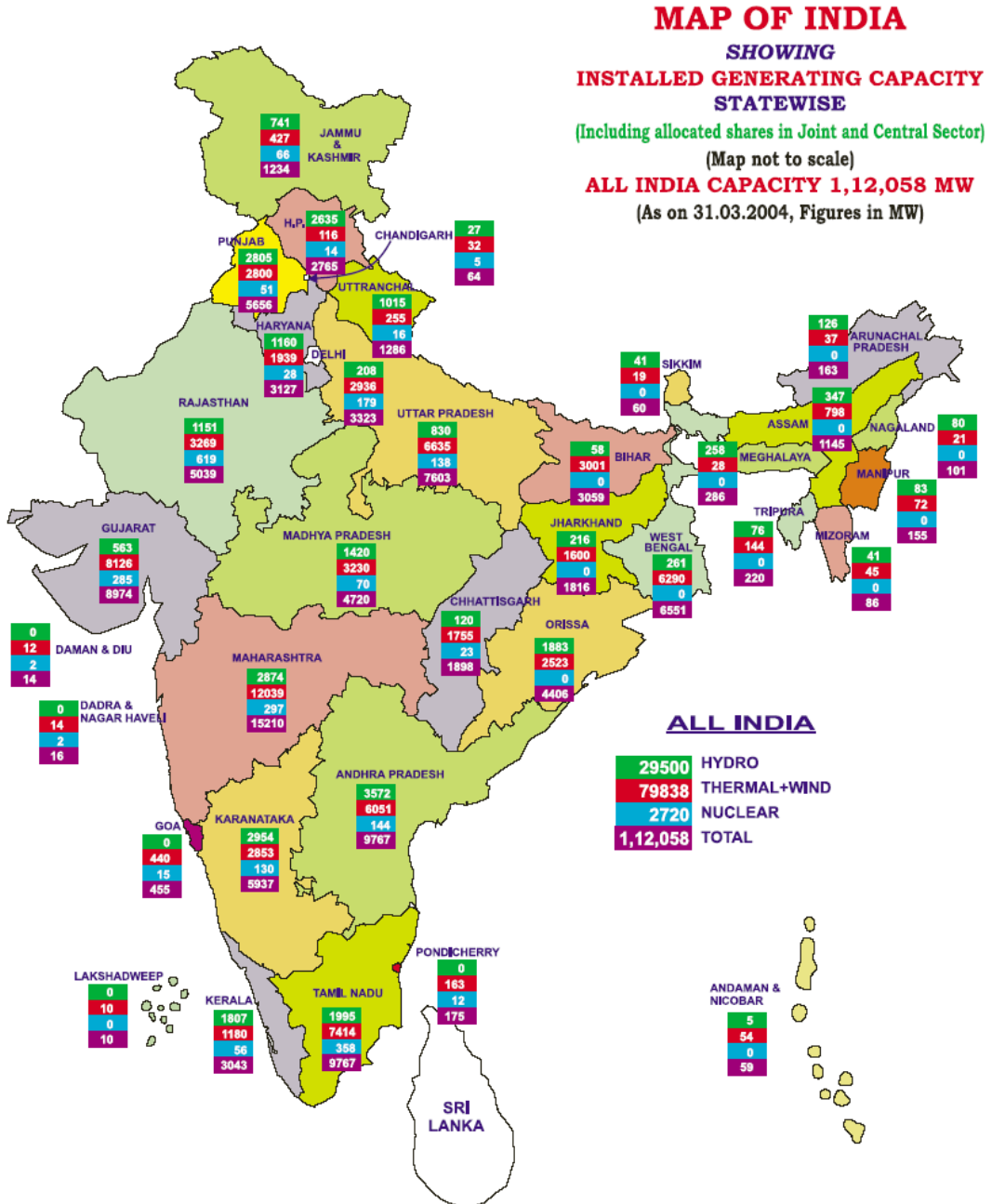
India must take care at this point to ensure that reforms continue to move forward as these and other questions are explored. Steps should be taken to prevent sudden policy reversals by state governments, particularly in politically sensitive areas such as application of user charges and arrangements for subsidies. Last but not the least, political and institutional mechanisms for sustaining political consensus must be considered. Forming a Standing Committee of Chief Ministers, or perhaps a Cabinet Committee under the Prime Minister to ensure progress in these critical areas, are a few options.

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Figure 1



Source: Ministry of Power Annual Report 2003

APPENDIX 1**Market Design: Summary**Generation*Ownership:*

Mostly public, private participation encouraged since 1991 and participation increasing. No current restrictions on concentration of private ownership. The private sector only accounts for about 10% of the total capacity of 107,000 MW as of 2002-3.

Conditions of supply & pricing:

Current: Rate of return regulation, two-part tariff for fixed and variable costs, based on interest allowance, O&M (subject to operating norms), depreciation, taxation, interest on working capital. Rate of return no longer guaranteed (fewer pass throughs, normative levels instead of actual used for pricing). Power purchased via Purchase Power Agreements. Also Availability Based Tariff (ABT) in market for balancing services in inter-state transmissions.

Future: Reduction of lengths of PPA, blocks of power sold in power market. Encouragement of power trading, development of competitive market for trading. Tariffs based on transparent bidding according to central government guidelines TBD. Separate ABT pricing for balancing services for all transmissions. Power also to be bought from “captive generators” under contracts for blocks of power.

Conditions for hedging TBD

Capacity expansion:

Shared responsibility of central and state government to plan, private sector bids on & builds project.

Transmission*Ownership:*

Nearly all public. Private participation in maintenance since 1998, private ownership allowed in EA 2003. The Central Government-owned Power Grid Corporation of India Limited (PGCIL) provides the bulk of inter-regional connectivity, with state transmission utilities providing much of the rest of the infrastructure. Private participation is beginning, however: the Central Electricity Regulatory Commission (CERC) issued a transmission license to Tala Delhi

Transmission Company Ltd., a JV Company between POWERGRID (49%) and Tata Power (51%) in October 2003.

Access:

Open access (EA 2003); also allowable to build parallel/alternate transmission networks if costs of existing facilities objectionable. EA 2003 stipulates 5 year transition, transition TBD.

System Operation:

Regional Load Dispatch Centers under review.

Pricing of services:

MYT tariff for long-term contracts, access prices based on competitive bidding for short-term contracts, with floor at previous year's average cost per unit per day. Zonal stamp proposed for inter-state transmission. (Previously separate charges for state, inter-state, inter-region, leading to pancaking) Charges for transmission loss based on average losses in national transmission system. Transmission networks likely to remain heavily subsidized until distribution sector surcharges are rationalized.

Process for capacity expansion:

Central government prepares reference document for private and public sector investment.

Distribution/Retail

Distribution and retail currently bundled together. Distributor responsible for metering, billing, enforcement, as well as building network access structures.

Ownership & Control:

Public, most generation by State Electricity Boards. A few areas such as Delhi and Bombay are private. Private participation encouraged by EA 2003. Spillover from captive power to designate areas becoming more common. Interest in privatization rising since EA 2003. Terms of privatization include schedules for reducing distribution losses in time-bound programme.

Oversight:

State Electricity Regulatory Commissions (SERCs) following broad guidelines issued by Central ERC.

Pricing:

Currently rate of return, with variation across states in accounting norms, little metering in agriculture, nearly 100% metering other consumers (though theft/losses led to understated actual consumption), and heavy cross-subsidization from industrial to agricultural users.

Move toward MYT, operating performance parameters TBD. “Uncontrollable” costs – fuel price, change in unit price of power, inflation can be passed through, “controllable” costs such as employee costs, repair & maintenance, cannot be passed through to consumers. As in generation, based on normative parameters rather than actual. Subsidies to be based on cost-of-service. Universal metering a goal.