

92490

A WORLD BANK STUDY



Beyond Crisis

THE FINANCIAL PERFORMANCE OF INDIA'S
POWER SECTOR

Beyond Crisis

A WORLD BANK STUDY

Beyond Crisis

The Financial Performance of India's Power Sector

Mani Khurana and Sudeshna Ghosh Banerjee

© 2015 International Bank for Reconstruction and Development / The World Bank
1818 H Street NW, Washington DC 20433
Telephone: 202-473-1000; Internet: www.worldbank.org

Some rights reserved

1 2 3 4 17 16 15 14

World Bank Studies are published to communicate the results of the Bank's work to the development community with the least possible delay. The manuscript of this paper therefore has not been prepared in accordance with the procedures appropriate to formally edited texts.

This work is a product of the staff of The World Bank with external contributions. The findings, interpretations, and conclusions expressed in this work do not necessarily reflect the views of The World Bank, its Board of Executive Directors, or the governments they represent. The World Bank does not guarantee the accuracy of the data included in this work. The boundaries, colors, denominations, and other information shown on any map in this work do not imply any judgment on the part of The World Bank concerning the legal status of any territory or the endorsement or acceptance of such boundaries.

Nothing herein shall constitute or be considered to be a limitation upon or waiver of the privileges and immunities of The World Bank, all of which are specifically reserved.

Rights and Permissions



This work is available under the Creative Commons Attribution 3.0 IGO license (CC BY 3.0 IGO) <http://creativecommons.org/licenses/by/3.0/igo>. Under the Creative Commons Attribution license, you are free to copy, distribute, transmit, and adapt this work, including for commercial purposes, under the following conditions:

Attribution—Please cite the work as follows: Khurana, Mani, and Sudeshna Ghosh Banerjee. 2015. *Beyond Crisis: The Financial Performance of India's Power Sector*. World Bank Studies. Washington, DC: World Bank. doi:10.1596/978-1-4648-0392-5. License: Creative Commons Attribution CC BY 3.0 IGO

Translations—If you create a translation of this work, please add the following disclaimer along with the attribution: *This translation was not created by The World Bank and should not be considered an official World Bank translation. The World Bank shall not be liable for any content or error in this translation.*

Adaptations—If you create an adaptation of this work, please add the following disclaimer along with the attribution: *This is an adaptation of an original work by The World Bank. Responsibility for the views and opinions expressed in the adaptation rests solely with the author or authors of the adaptation and are not endorsed by The World Bank.*

Third-party content—The World Bank does not necessarily own each component of the content contained within the work. The World Bank therefore does not warrant that the use of any third-party-owned individual component or part contained in the work will not infringe on the rights of those third parties. The risk of claims resulting from such infringement rests solely with you. If you wish to re-use a component of the work, it is your responsibility to determine whether permission is needed for that re-use and to obtain permission from the copyright owner. Examples of components can include, but are not limited to, tables, figures, or images.

All queries on rights and licenses should be addressed to the Publishing and Knowledge Division, The World Bank, 1818 H Street NW, Washington, DC 20433, USA; fax: 202-522-2625; e-mail: pubrights@worldbank.org.

ISBN (paper): 978-1-4648-0392-5

ISBN (electronic): 978-1-4648-0393-2

DOI: 10.1596/978-1-4648-0392-5

Cover photo: NOAA. This photograph is in the public domain and available for public use. Please credit NOAA.

Cover design: Debra Naylor, Naylor Design, Inc. / Bill Praguski, Critical Stages, LLC.

Library of Congress Cataloging-in-Publication Data has been requested.

Contents

<i>Preface</i>	<i>xi</i>	
<i>Acknowledgments</i>	<i>xiii</i>	
<i>Abbreviations</i>	<i>xv</i>	
Executive Summary	1	
Sector Finances Have Reached Crisis Proportions	2	
Some States Have Performed Worse Than Others	3	
Banks and Other Financial Institutions Have Increased Their Support	4	
Costs Have Been Driven Primarily by Power Procurement, Underpinned by Fuel Crisis	5	
The Gap between Costs and Revenues Has Increased	6	
The Financial Situation of the Power Sector Reflects a Complex Interplay between Utilities and Key Stakeholders	7	
Efficiency Improvements in Upstream Generation Can Bring about Significant Savings	8	
Financial Projections Suggest a Continued Slide until 2017	9	
A Proposed Simple Tool to Monitor Sector Performance on a Regular Basis	10	
A Few Areas of Continued Focus Can Go a Long Way to Improve Sector Performance	11	
Notes	13	
Chapter 1	The Genesis of India's Power Sector Reforms	15
	The Reforms and Their Origins	15
	Events Leading Up to the Electricity Act, 2003	17
	Accelerated Power Development and Reforms Program	22
	Notes	23
	References	24

Chapter 2	Deteriorating Sector Finances	25
	A Snapshot of Sector Finances	25
	Cost and Revenue in the Distribution Segment	32
	The Gap between Cost and Revenue	37
	Notes	42
	Reference	43
Chapter 3	The Roles of Different Stakeholders in the Current Power Sector Scenario	45
	The Present Crisis and Its Ripple Effects	45
	Key Stakeholders That Contributed to the Present Crisis	51
	The Bailout Package of 2012	60
	Note	64
	Reference	64
Chapter 4	Inefficiency in the Power Sector	65
	Inefficiency in Generation and Distribution Operations	65
	Notes	72
	Reference	72
Chapter 5	One Solution Does Not Fit All	73
	Some States Will Perform Better Than Others	78
	Group 1: Poor Performers That Need Critical Interventions to Improve Financial Performance	78
	Group 2: Top Performers	88
	Group 3: Poor Performers for Whom the Turnaround May Be Easier	96
	Risks to the Financial Position of the Power Sector in the Future	98
	Notes	99
Chapter 6	A Framework for Monitoring the Performance of the Power Sector	101
	The State Performance Index	101
	Suggestions on a Way Forward	107
	Note	110
Appendix A	List of Definitions	111
Appendix B	The Abraham Committee Report	113
	Key Findings	113
	Key Recommendations	114

Appendix C	Bailout Package of 2012	115
Appendix D	The Appellate Tribunal for Electricity Judgment of 2011	117
Appendix E	Advanced Benchmarking Techniques	119
	Use of Data Envelopment Analysis	119
	Advantages	120
	Limitations	120
Appendix F	Assumptions Used for Financial Projections	121
	Average Pooled Power Purchase	122
	Approach Applied	122
	State-Specific Units Availability Projection	122
	Applying State-Specific Fixed Costs and Variable Costs	124
	Computation of Weighted Average Pooled Power Costs	127
	Notes	129
	References	131
Boxes		
1.1	The Electricity Act, 2003, and Subsequent Policies	19
5.1	Feeder Segregation: The Jyotigram Yojana in Gujarat	89
5.2	The West Bengal Power Sector	89
6.1	Method for Construction of Performance Index Using AHP Analysis	103
Figures		
ES.1	Profit (Loss) after Tax, 2003–11	2
ES.2	Accumulated Losses, by State, 2003–11	3
ES.3	Power Sector Debt	4
ES.4	Power Purchase Efficiency Scores	5
ES.5	Cost Recovery Performance, 2003–11	6
ES.6	Decomposition of Losses, 2003 and 2011	7
ES.7	Projected Change in Gap without Subsidy, 2011 and 2017	9
ES.8	Best and Worst Performing States in the AHP Index	10
1.1	Peak and Energy Deficit	17
1.2	Timeline of Sector Unbundling and Establishment of Regulatory Commissions	17
1.3	Accumulated Losses, by State, 2003	19
1.4	Power Sector Structure, by State	21
2.1	Profit (Loss) after Tax, 2003–11	26
2.2	Profit (Loss) after Tax, by State, 2011	27

2.3	Accumulated Losses, by State, 2003–11	28
2.4	Evolution of Subsidies, 2003–11	30
2.5	Debt in the Power Sector	31
2.6	Analysis of Average Cost, 2011, and Compound Annual Growth Rate, 2003–11	32
2.7	Composition of Total Costs, 2003–11	33
2.8	Power Purchase Efficiency Scores	34
2.9	Energy Deficit Caused by Coal Shortages, 2012	35
2.10	Revenues in 2011 and Compound Annual Growth Rate	36
2.11	Cost Recovery Performance, 2003–11	37
2.12	Cost Recovery Performance with and without Subsidy	38
2.13	Evolution of the Cost-Revenue Gap	39
2.14	Decomposition of Losses in 2003 and 2011	39
2.15	Average Effective Tariff, by Consumer Group, 2012	40
2.16	Distribution Losses, 2003–11	41
2.17	Collection Rate, 2003–11	42
3.1	Outstanding Loans, Distribution, by Type of Loan and by Private Creditor	46
3.2	Utility Borrowing, by Term, 2007–10	47
3.3	Opportunities for the Private Sector in Generation and the Short-Term Market	47
3.4	State Support as a Share of State Budget and State GDP	48
3.5	Peak Deficit and Short-Term Prices, Daily, June–December 2012	49
3.6	Gap between BSE Power Index and BSE SENSEX, January 2008–March 2013	50
3.7	Impact on Disallowances of the Variation between Approved and Actual Transmission and Distribution Losses in Orissa, 2006–11	52
3.8	Transmission Company Costs Filed versus Approved, 2011	52
3.9	Agricultural Tariffs and Average Revenue Realized	53
3.10	Comparison of Power Costs through Intrastate Open Access and through Distribution Utilities, 2011	55
3.11	Number of Tariff Revisions, by State, 2007–13	57
3.12	Lending by Financial Institutions to Different Segments of the Power Sector	58
3.13	Funded Loans to the Power Sector as a Proportion of the Net Worth of Major Banks, 2010	59
3.14	The Vicious Circle of Costs and Inefficiency	60
4.1	Thermal Power Plant Status by State	68
4.2	DEA Scores for States, 2010	71
4.3	Efficiency Scores for States: Financial Gap Model, 2006 and 2010	71
5.1	Projected Power Sector Financial Performance	74
5.2	Projected External Support from All Sources for the Power Sector, 2011–17	75

5.3	Projected PAT of Distribution Segment, 2017	76
5.4	Projected Change in Gap without Subsidy, 2011 and 2017	76
5.5	Gap with and without Subsidies, 2017	77
5.6	Debtor Days and T&D Losses	77
5.7	Efficiency Indicators for Bihar, 2003–11	79
5.8	Reduction of the Gap (without Subsidy) in Bihar with Efficiency and Tariff Improvements	80
5.9	Efficiency Indicators for Uttar Pradesh, 2005–11	81
5.10	Reduction of the Gap (without Subsidy) over 5 Years with Efficiency and Tariff Improvements	82
5.11	Andhra Pradesh: Power Purchases	85
5.12	Estimates for Short- and Long-Term Power Requirement in Kerala	87
5.13	Five-Year Gap Reduction, Kerala	88
5.14	T&D Losses in West Bengal and Gujarat	90
5.15	West Bengal: Accumulated Profits and Losses, by Segment	91
5.16	Gujarat: Accumulated Profits and Losses, by Segment	92
5.17	Gujarat: Growth in Cost Components, 2004–11	93
5.18	West Bengal: Impact of Efficiency Improvement on Financial Gap (without Subsidy)	94
5.19	Gujarat: Impact of Efficiency Improvements on Financial Gap (without Subsidy)	94
5.20	Maharashtra: T&D Losses, 2003–11	95
5.21	Maharashtra: Impact of Efficiency Improvements on Financial Gap (without subsidy)	96
5.22	Punjab: Impact of Efficiency Improvements on Financial Gap (without subsidy)	97
6.1	Performance Index for States, 2006–10	104
E.1	Simple Illustration for DEA, Showing Cost and Output Relationship for Six Utilities	120
F.1	Approach for Forecasting APPC	122

Tables

1.1	Comparative Assessment of Technical and Operational Indicators	18
2.1	Accumulated Losses across the Power Sector Value Chain, 2011	29
2.2	Tariff Performance and Utility Losses, 2011	40
3.1	Regulatory Assets of Major States, March 31, 2012	54
3.2	Banks with Maximum Exposure to the Power Sector and the States They Have Lent to, 2010	59
3.3	Comparison of the 2001 and 2012 Bailout Packages	62

3.4	Key Stakeholder Risks and Rewards of the 2012 Bailout Package	63
3.5	Status and Projections of Candidate States for Financial Restructuring	63
4.1	DEA Efficiency Measurement Factors	66
4.2	Comparison of Inefficient Use of Fuel in Comparison with National Station Heat Rates and Most Efficient Plants	68
4.3	Top Five and Bottom Five in DEA Scores, 2006–10	70
5.1	Rajasthan: Sensitivity Analysis of Cumulative Financial Gap to Decline in Interest Rate, over 5 Years	83
5.2	Rajasthan: Sensitivity Analysis of Cumulative Financial Gap to Tariff Rate and Efficiency Improvements, over 5 Years	83
5.3	Tamil Nadu: Sensitivity Analysis of Operating Cash Gap to Financial Improvements, over 5 Years	83
6.1	Proposed Performance Parameters in AHP	102
6.2	Parameters Used in the Ministry of Power Ratings Methodology	106
F.1	Components of Financial Projections	121
F.2	Capital Cost Assumptions	125
F.3	Variable Cost Assumptions	126
F.4	Projected T&D Losses, 2009/10 to 2016/17	127
F.5	Assumptions for Capital Expenditures and R&M Cost— Establishing Relationships through Regression Analysis	128

Preface

In September 2012, the Cabinet Committee on Economic Affairs approved a financial rescue scheme to revive the power generation sector. This bailout amounted to about Rs 1.9 trillion and came in response to banks and other financial institutions with large nonperforming loans to the power sector. This is the second bailout of the sector in a decade. The first was in 2002 when the government had to convert the outstanding arrears of state electricity boards to central public sector undertakings. The 2002 bailout required Rs 400 billion in state government bonds to restore the sector to financial solvency. The recent crisis and consequent bailout is more complicated than the 2002 bailout. Power sector developments in the past two decades have brought new players into a traditionally government-dominated sector, and these new players have also been implicated in the crisis.

India has adopted transformative policy changes since the last bailout. A landmark Electricity Act was passed in 2003, superseding all previous legislation. The strategic intent of the act was to promote competition by opening all possible avenues for the procurement and sale of electric power. Subsidiary policies and enabling legislation have advanced this process. Competitive markets have evolved and attracted new investments, largely from the private sector. The institutional structure of the traditionally public sector–dominated industry has also been transformed. Aside from the entry of new private sector participants, primarily in generation, the state electricity boards were unbundled into generation, transmission, distribution, and, in a few cases, trading segments. State electricity regulatory commissions were also established in all the states.

Over the next two decades, India faces immense challenges if it is to sustain the 8 to 10 percent growth rate required to end poverty and achieve human development goals. According to the Planning Commission, India needs to triple or quadruple its primary energy supply and increase its installed electricity capacity by at least five or six times its 2004 levels to meet demand in 2032. By 2032, India will need a total primary energy supply of approximately 80 million terajoules, almost triple its 2010 supply of 29 million terajoules and requiring a compound annual growth rate of 4.7 percent. To accomplish these ambitious goals, India will need a commercially viable power sector.

This report presents a diagnostic of the financial and operational performance of segments in the power sector value chain between adoption of the Electricity Act, 2003, and 2011, including analysis of the factors that contributed to the recent crisis. The report focuses on efficiency and productivity, whether performance has improved over time, and which states have emerged as performance leaders. Analysis of this kind is not new or unique, but this report aims to integrate historical performance, the current situation, future projections of the impact of worsening sector finances, and the actions that need to be taken to check the downturn. The report draws primarily from utility data collected by the Power Finance Corporation in successive years on utilities' operational and financial performance. The Power Finance Corporation data were collated into a single database with the addition of various operational parameters at the plant level and the utility level from the Central Electricity Authority.

The data underpinning this report is publicly available as the India Power Sector Review Database in the World Bank's Open Data Platform: <http://databank.worldbank.org/data/views/variableselection/selectvariables.aspx?source=india-power-sector-review-database>.

Acknowledgments

This study was carried out at the request of the Department of Economic Affairs of India, under the auspices of the umbrella work program on the India Power Sector Review, led by Sheoli Pargal and Sudeshna Ghosh Banerjee. The core team for this study comprised Mani Khurana, Sudeshna Ghosh Banerjee, Pranav Vaidya, Bartley Higgins, and Sanjukta Roy.

The report draws from a background study and analysis prepared by a consulting team from AF-Mercados EMI led by Anish De and Puneet Chitkara and consisting of Sanchit Kumar, Debadrita Dhara, Anvesha Thakkar, and Shilpa Sethia.

The team is grateful to Rohit Mittal, Sheoli Pargal, Mohua Mukherjee, and Ashish Khanna for discussions and constructive ideas at various stages of this work. Thanks are also due to the Technical Advisory Panel members of the India Power Sector Review, notably J. L. Bajaj and Rajat Mishra, as well as Sharmila Chavaly from the Department of Economic Affairs, for their advice and suggestions. Finally, the team thanks peer reviewers Raihan Elahi and Mohammed Saqib for their substantive comments.

The authors are grateful for the financial support of the Energy Sector Management Assistance Program and the Australian Aid Trust Fund.

Abbreviations

ABT	Availability-based tariff
AC	Average cost
ACS	Average cost of supply
AHP	Analytic hierarchy process
APPC	Average pooled power cost
AR	Average revenue
ARR	Average revenue realized
AT&C	Aggregate technical and commercial
ATE	Appellate Tribunal for Electricity
BPL	Below poverty line
BSEB	Bihar State Electricity Board
CAGR	Compounded annual growth rate
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CGRF	Consumer grievance redressal forum
CIL	Coal India Limited
DAM	Day-ahead market
DEA	Data envelopment analysis
DPR	Detailed project report
DSM	Demand-side management
EPS	Electric Power Survey of India
ERC	Electricity Regulatory Commission
FIT	Feed-in tariff
G,T,D	Generation, transmission, distribution
GDP	Gross domestic product
HT/LT	High tension/low tension
IDFC	Infrastructure Development Finance Company
IEX	Indian Energy Exchange
IT	Information technology
JGS	Jyotigram Scheme
KSEB	Kerala State Electricity Board

KSERC	Kerala State Electricity Regulatory Commission
MSEDCL	Maharashtra State Electricity Distribution Company Limited
NTP	National Tariff Policy
O&M	Operating and maintenance
PAT	Profit after tax
PBT	Profit before tax
PFC	Power Finance Corporation
PFP	Partial factor productivity
PPP	Public-private partnership
R&M	Renovation and modernization
R-APDRP	Restructured Accelerated Power Development and Reform Program
REC	Rural Electrification Corporation
RGGVY	Rajiv Gandhi Grameen Vidyutikaran Yojana
SCC	Specific coal consumption
SEB	State electricity board
SERC	State electricity regulatory commission
SFA	Stochastic frontier analysis
SLDC	State load dispatch center
SOC	Specific oil consumption
T&D	Transmission and distribution
TFP	Total factor productivity
TJ	Terajoules
Transco	Transmission company
UI	Unscheduled interchange
WBSETCL	West Bengal State Electricity Transmission Company Limited
Y-o-Y	Year-on-year

All dollar amounts are U.S. dollars unless otherwise indicated.

Executive Summary

At the end of 2011, the Indian power sector found itself in financial crisis—just a decade after the 2001 bailout of state electricity boards (SEBs) by the central government. Bankrupt state power distribution utilities in several states were unable to pay their bills or repay their debts. Despite the passage of the landmark 2003 Electricity Act and implementation of a broad set of reforms over the past decade, the sector today is looking at another rescue from the center, four times larger than before. This financial rescue scheme amounts to about Rs 1.9 trillion (\$42 billion)¹ and was instigated by the nonperforming assets of the banks and other financial institutions. The Electricity Act was envisaged to create independent companies functioning on commercial principles, but they are still far away from that goal.

The power sector has to expand if India is to meet the country's ambitious growth targets of 8–10 percent over the next two decades. According to the Planning Commission, India must triple or quadruple its primary energy supply and increase its installed electricity capacity by at least five or six times 2003/04 levels to meet demand in 2031/32. By 2032, India will require a total primary energy supply of approximately 80 million TJ (terajoules), almost triple the 2010 output of 29 million TJ, requiring a compound annual growth rate of 4.7 percent.

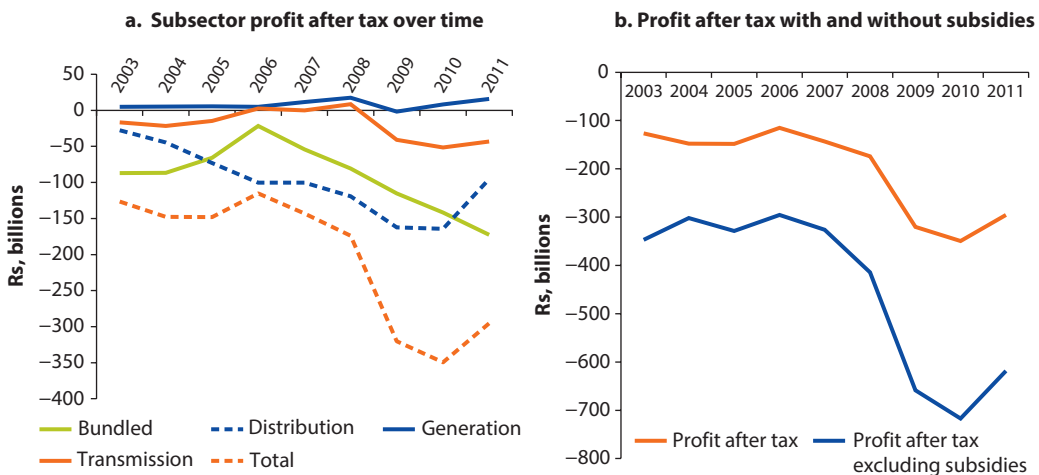
This report therefore reviews the financial and operational performance of segments in the power sector value chain since adoption of the Electricity Act 2003 and the factors that contributed to the recent crisis. It focuses on efficiency and productivity, whether performance has improved over time, and which states have emerged as performance leaders. Analysis of this kind is not new or unique, but this report aims to integrate historical performance, the current scenario, projections into the future of the impact of worsening sector finances, and the actions that need to be taken to check the downturn.

Sector Finances Have Reached Crisis Proportions

Utility finances have continued to worsen considerably on a year-to-year basis, reaching a point that has been termed “India’s subprime crisis.” The crisis has intensified since 2006, reaching mammoth losses of some Rs 618 billion (\$14 billion), equivalent to 0.7 percent of India’s gross domestic product (GDP) and 17 percent of gross fiscal deficit in 2011. The opportunity cost of these losses is huge. Compared with the 11th Plan outlay in different sectors, the losses account for 44 percent of spending on health care or nearly 23 percent of education spending. Traditionally, governments have used subsidies to cover below-cost-recovery tariffs charged to agriculture and domestic consumers. Total subsidies in 2011 were Rs 323 billion (\$7 billion), and profit after tax (PAT) adjusted for subsidies booked was Rs (-) 295 billion (\$6.5 billion) in 2011.

These losses are overwhelmingly located in the bundled SEBs followed by the unbundled distribution companies. The upstream generation segment recorded a small profit of Rs 15 billion (\$344 million) (figure ES.1). States with bundled power sectors have been on a downward slide from 2006 onward, with only Kerala registering profits in 2011. The generation segment has usually been profitable, registering profits every year except for miniscule losses in 2009. The transmission segment had become profitable in the mid-2000s and then slid back into large losses later in the decade. However, these losses came primarily from Uttar Pradesh (UP), with the remaining 14 state transmission companies recording either profits or relatively small losses. The distribution segment recovered slightly in 2011 after experiencing plummeting losses. Delhi has the most profitable distribution sector by far, registering profits of Rs 8 billion in 2011. Among

Figure ES.1 Profit (Loss) after Tax, 2003–11



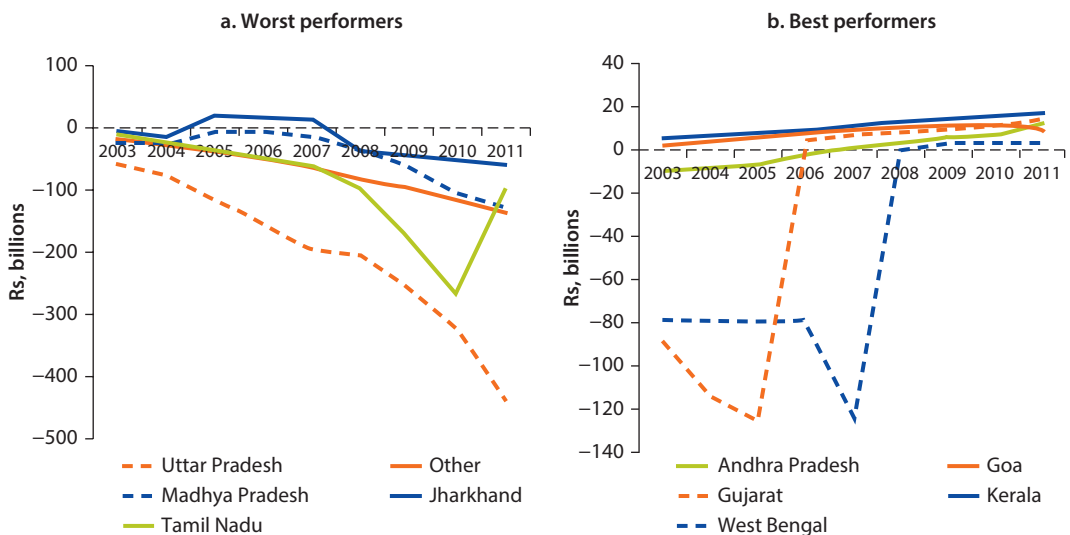
the unbundled distribution companies and SEBs, only nine states experienced an upside in distribution finances between 2003 and 2011 in real terms.

Some States Have Performed Worse Than Others

Five states—Kerala, Gujarat, Andhra Pradesh, Goa, and West Bengal—reported accumulated profits of Rs 58 billion in 2011. Gujarat and West Bengal are credited with dramatic turnarounds from large accumulated losses to their current robust finances. Gujarat and UP have followed opposite performance trajectories since 2003, when their accumulated losses were similar. Gujarat went on to record its second highest accumulated profits in 2011. Aside from Gujarat, Andhra Pradesh and West Bengal transitioned from losses to profits in the mid-2000s. The most profitable power sector in the country is in Kerala (figure ES.2). Despite remaining a bundled utility, it is the only state that has consistently reported accumulated profits since 2003. The case of Goa is similar.

The accumulated losses are concentrated in a few states and account for a substantial part of their state GDP. Uttar Pradesh has remained in a free-fall situation since 2003 and alone contributed close to 40 percent of total accumulated losses in 2011, followed by states including Madhya Pradesh, Tamil Nadu, and Jharkhand. These four states account for an upward of 60 percent of India’s total accumulated losses. For North-East states such as Manipur, Mizoram, and Nagaland, the accumulated losses in 2011 corresponded to 14, 12, and 8 percent of state GDP, respectively.

Figure ES.2 Accumulated Losses, by State, 2003–11



Source: World Bank.

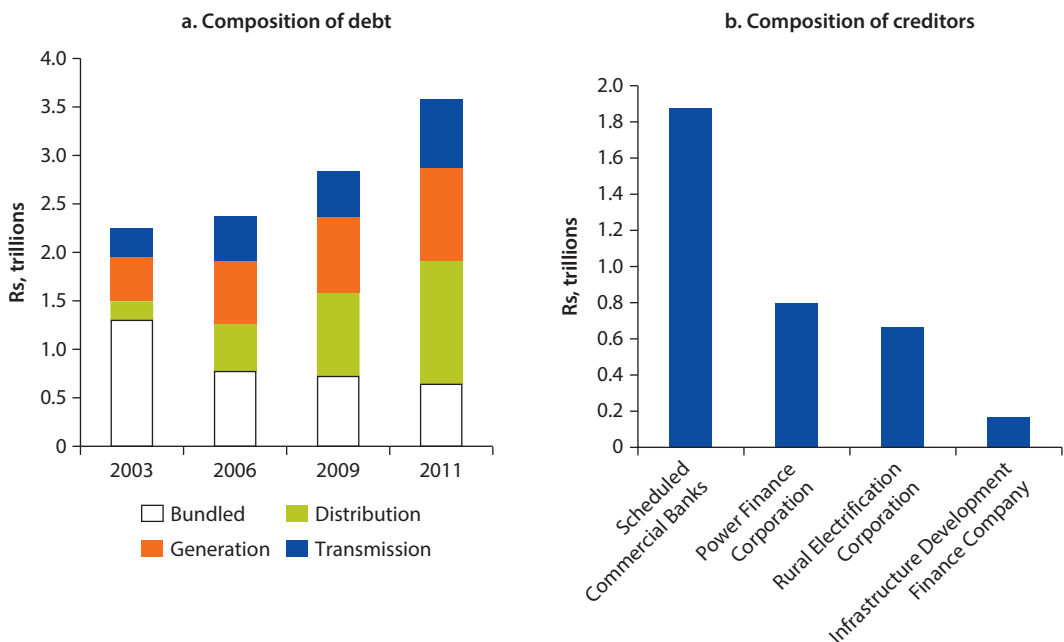
Banks and Other Financial Institutions Have Increased Their Support

Substantial borrowing by all segments has underpinned the dramatic expansion of the power sector. Debt in real terms grew the fastest in the distribution sector, at 23 percent, followed by the transmission and generation segments at 10 and 9 percent, respectively (figure ES.3a). The composition of debt among the utilities has evolved as well. In 2003, bundled and generation companies accounted for about 78 percent of the total debt of the power sector. The landscape in 2011 had changed dramatically, with distribution utilities accounting for the largest share of debt, at 36 percent, followed by generation and transmission utilities.

The total power sector debt equaled 5 percent of India’s GDP in 2011, though a few large states accounted for much of this debt. In Uttar Pradesh, Rajasthan, Meghalaya, and Haryana, the share is higher than 10 percent of state GDP. Ten states together are responsible for about 78 percent of India’s Rs 3.5 trillion (\$78 billion) power sector debt in 2011. Rajasthan has the largest debt, which grew at a phenomenal rate of 15 percent in real terms between 2003 and 2011. Only Bihar’s debt grew faster, but it started from a lower base.

In 2011, about half of the Rs 3.5 trillion power sector debt was held by commercial banks (figure ES.3b). Lending to the sector has been fueled by heightened short-term borrowing to distribution companies to meet their operating expenses, by new investment by state-owned generation and transmission companies, and by the unprecedented surge of investment in new generation projects on the part of private developers. The proportion of long-term loans has fallen

Figure ES.3 Power Sector Debt

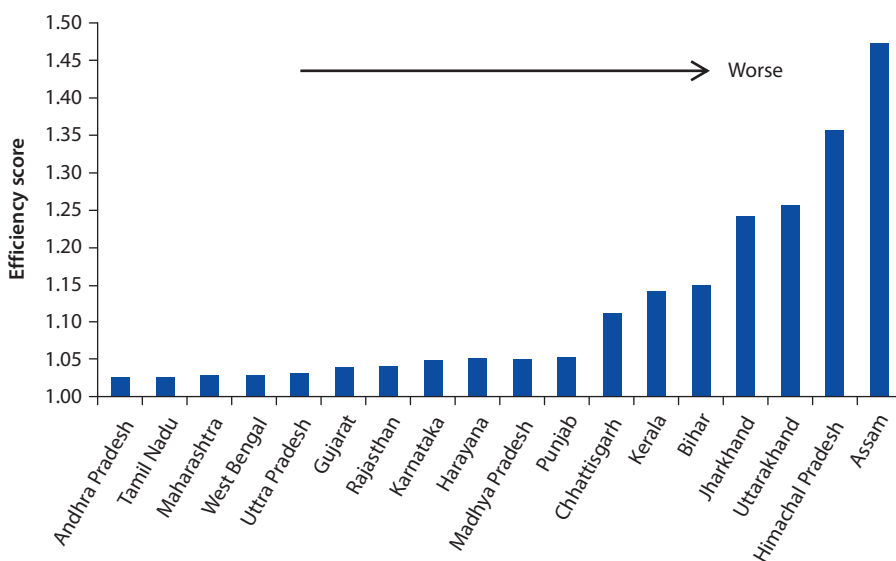


over the years. A group of six states—Andhra Pradesh, Haryana, Jharkhand, Karnataka, Punjab, and Rajasthan—have the largest share of short-term borrowing in their total debt.

Costs Have Been Driven Primarily by Power Procurement, Underpinned by Fuel Crisis

Power purchases are the most important cost component for the distribution segment. From 2009 onward, power purchases have been more than half of total costs, and this share climbed to 74 percent in 2011. Efficiency in state power purchase costs can be computed using a stochastic frontier analysis (SFA), controlling for hydrothermal mix, share of purchases from outside the state, and power purchase costs per unit (from outside the state). Using such an analysis, unity represents efficiency, and the higher the score the more inefficient the utility. All states are inefficient, and Assam, Bihar, Himachal Pradesh, Jharkhand, and Uttarakhand are the most inefficient (figure ES.4). It is evident that power purchase costs are very sensitive to the amount of power purchased outside the state, which is typically more expensive. Bihar and Jharkhand are inefficient essentially because the state-owned generators in those states are inefficient and have extremely low plant load factors. A favorable hydrothermal mix is also usually advantageous for the state. Both Himachal Pradesh and Uttarakhand have a high percentage of hydro resources, but during times of low production, these states must enter into short-term contracts, usually at high prices, and this leads to inefficiency in power purchase costs. These states have therefore been unable to capitalize on their hydro resource availability.

Figure ES.4 Power Purchase Efficiency Scores



Source: World Bank.

The main driver of rising power purchase costs has been the increase in fuel costs. In India, more than 70 percent of base load power supply comes from coal-fired power plants. Coal India Limited (CIL), India's monopoly coal supplier, has not been able to increase production to meet demand. During the 11th Plan period (2007–12), coal-based power capacity increased by 9.5 percent annually, to 112 gigawatts from 68 gigawatts. During the same period, coal production increased only 5 percent per year. In 2012, the difference was much starker—installed coal-based capacity increased by 20 percent, whereas domestic coal production increased by only 1.4 percent. Consequently, 37 gigawatts of capacity was stranded in 2012, and uncertainty about long-term fuel supplies constrains new investment in power generation.

The Gap between Costs and Revenues Has Increased

On a per unit basis, cost recovery performance fluctuated throughout the entire period 2003–11 but remained within a band of 76–85 percent and averaged 82 percent (figure ES.5). In the initial years of this period, between 2003 and 2007, cost recovery rose because revenues rose faster than costs in real terms. However, during 2008–10 cost recovery declined sharply to a low point of 76 percent and then moderated in 2011 to 80 percent. The gap between costs and revenues was thus 20 percent in 2011.

The slower growth of revenues relative to costs has primarily been driven by a lack of tariff increases commensurate with cost increases (figure ES.6). In 2003, states were, in aggregate, charging an average billed tariff well above cost recovery levels, and losses in that year were overwhelmingly driven by distribution losses. In contrast, in 2011, states were, in aggregate, charging an average billed tariff below cost recovery levels. Fifteen states had an average billed tariff below cost recovery levels in 2011. Even then, distribution and collection losses

Figure ES.5 Cost Recovery Performance, 2003–11

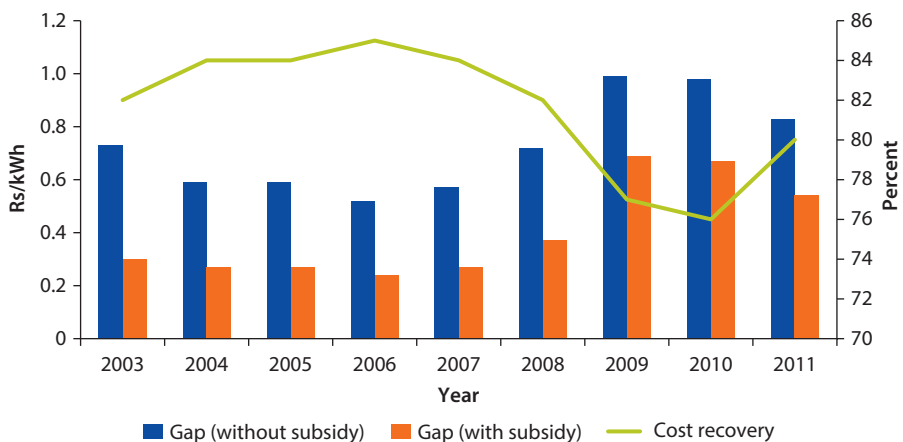
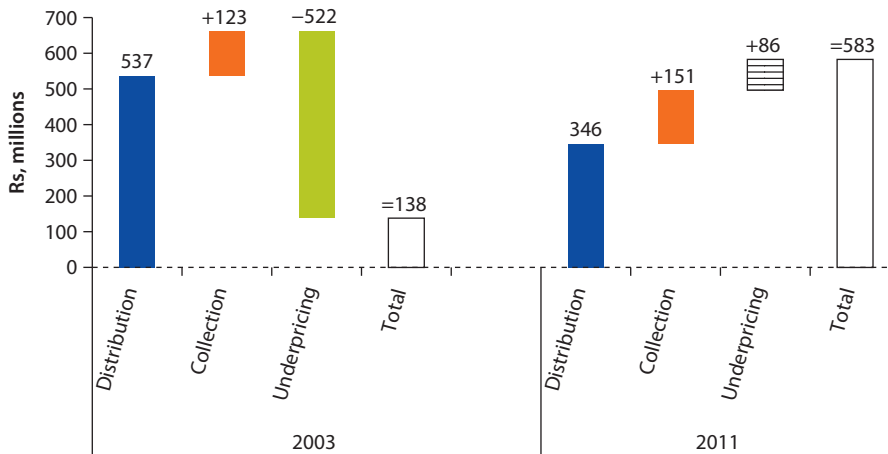


Figure ES.6 Decomposition of Losses, 2003 and 2011

contribute the largest part of total losses. The analysis suggests that a majority of the states can improve their financial performance by increasing their operational efficiency. A simple mapping of states with debtor days higher than 100 and distribution losses above 20 percent shows that the majority of Indian states fall in this category.

The Financial Situation of the Power Sector Reflects a Complex Interplay between Utilities and Key Stakeholders

Key stakeholders, which include regulators, state governments, and banks, influence the direction (or misdirection) of the power sector and have contributed to the current crisis in the sector.

First, a culture of independent regulation that protects long-term consumer and supplier interests has been replaced by short-term expediency. Disallowance of expenses, inaccurate estimates of agriculture consumption and its corresponding subsidy, buildup of regulatory assets, regulations like open access, and the return on capital are only some of the key points resulting in disconnects between the utilities and regulators.

Second, banks have provided loans to distribution companies to provide liquidity, seemingly overlooking prudent lending norms. Such lending has been based on the quasi-guarantee of state governments. Although many utilities have been insolvent, they have continued to receive loans from banks. A considerable part of the borrowing by distribution companies goes to meet their operating expenses, not to make investments. Unrestricted lending has also undermined banks' capital adequacy and net worth. An analysis of 13 major state-owned banks shows that more than half have funded loans to the power

sector equal to or greater than 50 percent of their own net worth. Unrestricted lending from banks has limited the accountability of distribution companies to improve performance and reduced the pressure on state governments to increase tariffs. Only in 2012 did banks reduce lending to the power sector, after most of the banks had reached their sectoral caps on lending and the Reserve Bank of India intervened. The states then finally reacted and pushed through tariff reforms to ensure that the lights stayed on. Another significant event that forced the states and state regulators to react was the judgment issued by Appellate Tribunal for Electricity (ATE), which gave the state electricity regulatory commissions (SERCs) the responsibility for determining tariffs if the distribution utilities failed to meet filing deadlines. This ruling led to a flurry of tariff increases.

Third, state governments have also been complicit. Electricity is an essential service used by all segments of society. But because electricity is a scarce resource, it has often been used as an instrument of political patronage. Although in theory electricity companies operate at arm's length from government, in practice this has rarely been the case. Because of the perception that tariff increases will cause political problems for an incumbent state government, states often did not allow utilities to file for tariff revision and thus tariff changes have been infrequent in many states.

Efficiency Improvements in Upstream Generation Can Bring about Significant Savings

Distribution inefficiencies are typically highlighted, but operational efficiency gains in the upstream generation segment can percolate down the value chain as well. Based on the analysis of 69 state-owned thermal plants in 2010, more than half of them should be either shut down or renovated and modernized. If the six worst-performing power plants operated at national station heat rate levels, more than 2,750 million kilowatt hours of additional electricity could be generated, leading to a cost savings of about Rs 9 billion for the generation companies. This would also enable the states to reduce their reliance on short-term purchases, leading to a further savings of about Rs 9 billion for the distribution companies. This gain in efficiency would particularly benefit Uttar Pradesh and Bihar, which together accounted for more than 30 percent of total short-term purchases in 2011.

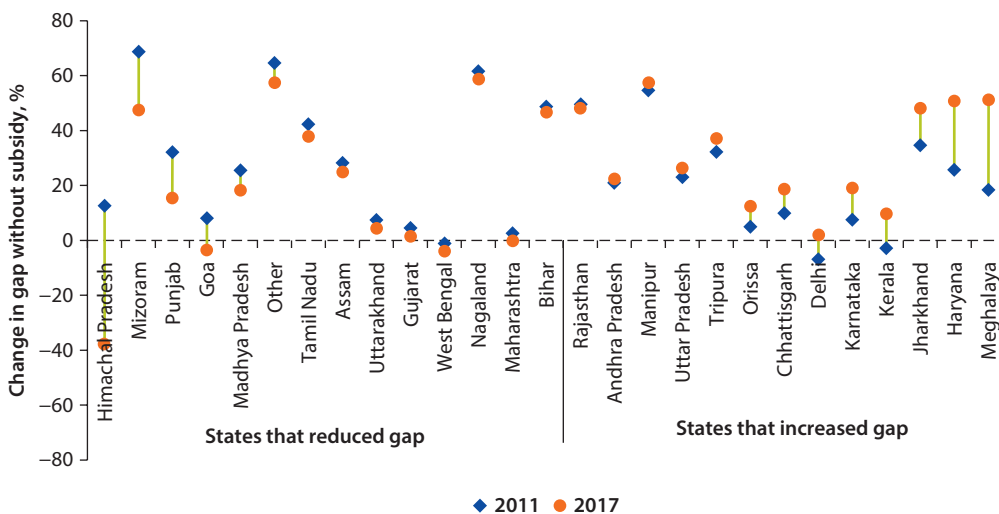
The savings would have been even greater, at Rs 15 billion, if the six worst-performing plants operated at heat rates similar to those of the best plants. If the coal used in these inefficient plants were to be used efficiently, thus reducing the need for imported coal, the utilities could therefore save on the order of Rs 20 billion. Even allowing for the fixed costs of the efficient plants, the utilities would still save Rs 15 billion.

Financial Projections Suggest a Continued Slide until 2017

The annual financial losses of the sector (excluding subsidies) are projected to be Rs 2,013 billion in 2017 if business as usual continues, compared to Rs 618 billion in 2011 (scenario 1). While the generation and transmission companies earn profits, the distribution companies are projected to continue to incur substantial losses. Even if tariffs rise by 6 percent every year to keep up with increases in the cost of supply, annual losses in 2017 are projected to be Rs 1,253 billion (scenario 2). A large part of this support is expected to come from government. Though in recent years bank/financial institution loans have contributed significant support to the power sector, its current risk profile has put continuation of this support at risk.

The gap between the average cost of supply and the average revenue earned per unit is the main driver behind these high financial losses and rising state support. According to the projections, in 2017 the gap will be less than 15 percent in only 10 states (figure ES.7).² Overall, 14 states manage to reduce the revenue gap trend between 2013 and 2017, while it increased in 13 states. Only five states are actually covering the cost of supply in 2017 (Goa, Himachal Pradesh, Kerala, Maharashtra, and West Bengal). The most dramatic change among these states is in Himachal Pradesh, which goes from moderate losses to profits during the period. Haryana and Meghalaya suffer the largest increase in the cost/revenue gap, signaling deteriorating performance. The gap in 2017 will be between 15 and 30 percent in six states. Of these states, Andhra Pradesh and Karnataka are both projected to perform considerably better when subsidies are taken into account.

Figure ES.7 Projected Change in Gap without Subsidy, 2011 and 2017

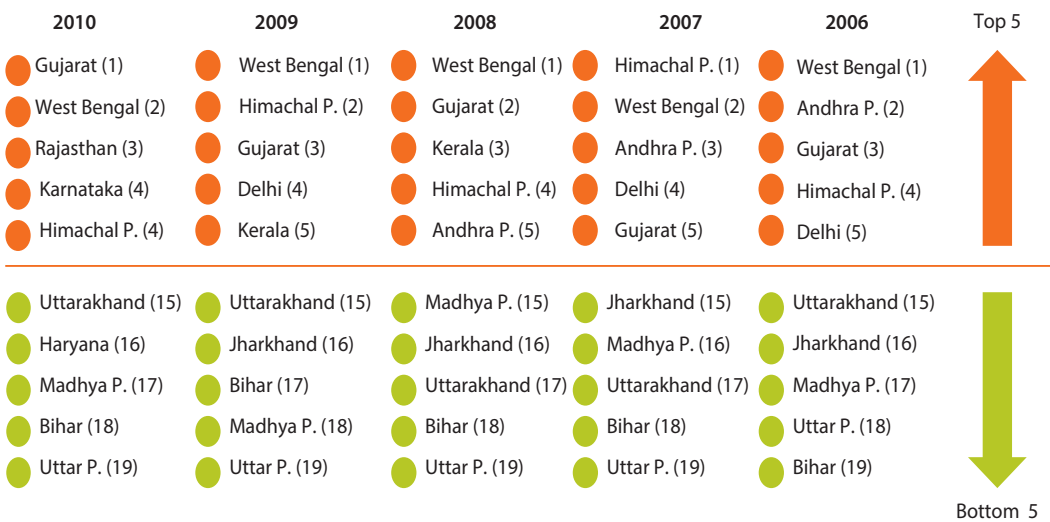


A Proposed Simple Tool to Monitor Sector Performance on a Regular Basis

To monitor power sector performance, a state performance index has been created using the analytic hierarchy process (AHP) method. This method was used to create a baseline of sector performance annually for 2006–10. Selected experts from financial institutions and banks were asked through a survey to make a pairwise comparison of various factors for the purposes of lending to the power sector. These 11 factors capture the financial and operational efficiency of the sector: gap after subsidy (AC–AR)/AC, subsidy/total cost, subsidy received/subsidy booked, transmission and distribution (T&D) loss, collection efficiency, debtor days, creditor days, (accumulated losses + subsidy)/current turnover, future gap (2017)/current AC, energy deficit, and power purchase cost/unit. The results of this simple tool were cross-checked against the more comprehensive and sophisticated data envelopment analysis (DEA) tool, and the results were remarkably similar.

Gujarat, West Bengal, and Himachal Pradesh occupied the top spots during the five-year period (figure ES.8). There is movement among the top scorers—Andhra Pradesh was on the top-five list until 2008 but fell behind in the last two years of the period. Kerala has reported steady improvement during the five-year period in debtor and creditor days as well as considerable improvement in its subsidy-received-to-booked ratio in 2007/08. Kerala and Karnataka have emerged as reasonable performers on both the technical and commercial parameters. Of the two, Karnataka has worse financial performance (very high debtor days), but it improved in the last two years of the period.

Figure ES.8 Best and Worst Performing States in the AHP Index



Note: Ranking of states out 29 in parenthesis

Uttar Pradesh, Bihar, and Madhya Pradesh continued to be the worst performers over the entire five-year period. Bihar and Jharkhand fared very poorly on most efficiency parameters (debtor days, collection efficiency, and T&D losses). These states would gain tremendously from cash collections by reducing debtor days from their abnormally high levels. In Bihar and Jharkhand, the power stations are either shuttered or operating at abysmal efficiency levels. Haryana and Punjab show high financial losses. Of the two, Haryana performs much more poorly on both generation and distribution. The problems of Punjab are more related to power purchase costs and tariff revisions.

Two conclusions emerge from the AHP analysis. *First, power purchase costs have played a key role in the deteriorating finances of the utilities.* Utilities that have planned their purchases better and relied on their own generation and contracted purchases have fared better than those that have relied on external purchases. The high tension/low tension (HT/LT) line ratio plays a very important role in T&D losses and consequently in power purchase costs, which in turn affects the financial gap. Poor network capacity planning (allowing additional connections without adequate network investment) has a significant impact on T&D losses. *Second, efficiency improvements and tariff increases should go hand in hand.* In general, the states that have revised tariffs regularly have also improved efficiency, as evidenced by the performance of Gujarat, Kerala, and West Bengal. Their nominal increases have been adequate to offset rising costs. In contrast, the states that have neglected to increase tariffs are being hit the hardest. Maharashtra is an outlier because its utility has received reasonable tariff increases but has not improved efficiency commensurately. However, it has used the regular cash flows from tariff increases to moderate the effects of emergency purchases. States such as Jharkhand, Rajasthan, and Tamil Nadu that have not revised tariffs have seen declining efficiency as well.

A Few Areas of Continued Focus Can Go a Long Way to Improve Sector Performance

The most urgent need is to address the financial distress of the utilities while using the crisis as leverage to implement interventions to improve efficiency and other measures essential to the longer-term sustainability of the power sector. Below are a few recommendations emerging from the analysis presented in this report.

Improve the efficiency of existing plants to alleviate the current power shortage. In part, the power shortage crisis is a result of constraints outside the core power sector, particularly in fuel availability (of coal, gas, and also nuclear) and land acquisition. Protracted delays and difficulties with these issues have an exponential impact on both the availability and cost of power. Simultaneously, a majority of utilities have not responded in a timely manner to the need to augment power supplies using new sources, resulting in adverse impacts on utility and state finances. The majority of plants operated by state power utilities are characterized by low plant load factor and high station heat rate. This inefficiency

is due to poor operations and maintenance during the life of the plant. These plants need to be rehabilitated, or closed if rehabilitation is not a commercially viable option.

Focus on transmission system planning and strengthening of the network at the state level. Improvements are required in system planning. At present, system planning is reactive, and the states, barring exceptions, place no emphasis on prospective/proactive planning. The planning process (and the underlying forecasting and other related processes) must be strengthened. The state-level transmission networks are weak and must also be strengthened to meet load growth. Although investment flows in the transmission systems have improved since the reform process began, significant measures are required to increase the efficiency of the transmission system.

Use efficient planning to reduce power purchase costs and technical losses. Power purchases constitute more than 60 percent of total distribution company costs, and it is therefore crucial that utilities make comprehensive projections of short-, medium-, and long-term demand, including seasonal fluctuations in demand. Power procured on a short-term basis during energy-deficit conditions will be costly and will have adverse impacts on state finances. The aim should therefore be to minimize short-term purchases. In-depth demand assessment and network planning will help ensure that utilities' power distribution capabilities are adequate and efficient to meet not only current demand but future demand requirements as well.

Improve the quality of energy and financial data. The majority of state distribution companies in India must cope with incomplete metering, defective meters, and manual meter reading, leading to inadequate billing and revenue collection. There is an urgent need to focus on energy auditing to help contain aggregate technical and commercial losses. Financial data also needs to be reliable and audited in a timely manner for all the utilities. Publication of key monthly operational and financial data on the company website would enable public scrutiny of a performance "scorecard" and thus put pressure on the organization to improve performance.

Use innovative business models to improve financial and operational efficiency. Enhanced private participation through franchising and other means could help bring about improvements. The initial results of franchising programs in difficult areas, such as Bhiwandi in Maharashtra, are encouraging. The ambit of such programs could be enlarged to allow economies of scale and scope. An in-house model for revenue augmentation and loss reduction in urban areas should also be adopted. As a result of the tariff structure and load profile in most of the states, about 20 percent of consumers account for around 80 percent of revenue. To maximize return on investment, distribution utilities could focus on interventions and investments to increase revenues and reduce losses in key urban areas.

Focus on customer satisfaction. Distribution utilities need to focus on enhancing customer satisfaction by providing efficient and reliable service. Suitable technology interventions like providing power-cut information on consumers'

mobiles can be adopted to improve customer relations. Well-functioning customer service centers have increased customer satisfaction in many utilities.

Upgrade skills across all segments of the power sector. The utilities place little emphasis on human resources-related issues such as recruitment, succession planning, skill development, and training. With advances in various technologies there is an urgent need to hone the skills of the existing staff. To take an example, Restructured Accelerated Power Development and Reforms Programme (R-APDRP) promotes the use of information technology to improve energy auditing, reduce losses, and increase efficiency. The various states are at different stages of implementing R-APDRP, but these initiatives can be successful only if the capacity of the utility staff is improved through recruitment of workers with the appropriate skills and requisite training in information technology.

Notes

1. \$1=Rs 45.
2. Gap as a proportion of average cost = (average cost per unit-average revenue realized per unit)/average cost per unit.

The Genesis of India's Power Sector Reforms

The Reforms and Their Origins

The government of India has prioritized power sector development since the birth of the Indian nation in 1947. Electricity is a “concurrent” subject in the Indian constitution, which means that both the center and state legislatures must establish policy frameworks. This provision was further defined in the Electricity Supply Act of 1948, which paved the way for an institutional structure that established the Central Electricity Authority (CEA) as an advisory body on planning, policy making, and progress assessment. State electricity boards (SEBs) were also created as vertically integrated organizations responsible for generation, distribution, and transmission of power at the state level. In 1956, the Industrial Policy Resolution further expanded the role of the government, nationalizing the generation and distribution of electricity and abrogating existing private licenses (Bajaj and Sharma 2010; Panda and Patel 2011).

A watershed moment for the Indian economy occurred in 1991. Faced with a foreign exchange crisis, India embraced broad-based reforms and moved away from the inward-oriented industrial licensing system of the past. These reforms unleashed transformative trends in the Indian economy that established the power sector as a critical complement for national growth. India emerged as one of the fastest growing economies in the world, averaging growth of about 7 percent a year through 2011 and quadrupling its gross domestic product (GDP). Its rise to economic prominence has been comparable to that of China. This prosperity has played a large role in shifting India's urbanization patterns. During 1990–2010, India added more than 351 million people, 156 million in cities. Urban population growth accounted for more than 44 percent of total population growth. The demand for energy originates not only in this economic growth but also from the need to provide 400 million people with access to electricity at the beginning of the new century. Achieving this access agenda has been high on

successive governments' development agendas, and a flagship rural electrification program, Rajiv Gandhi Grameen Vidyutikaran Yojana, was established in 2005 to support the national goal of universal access to electric power.

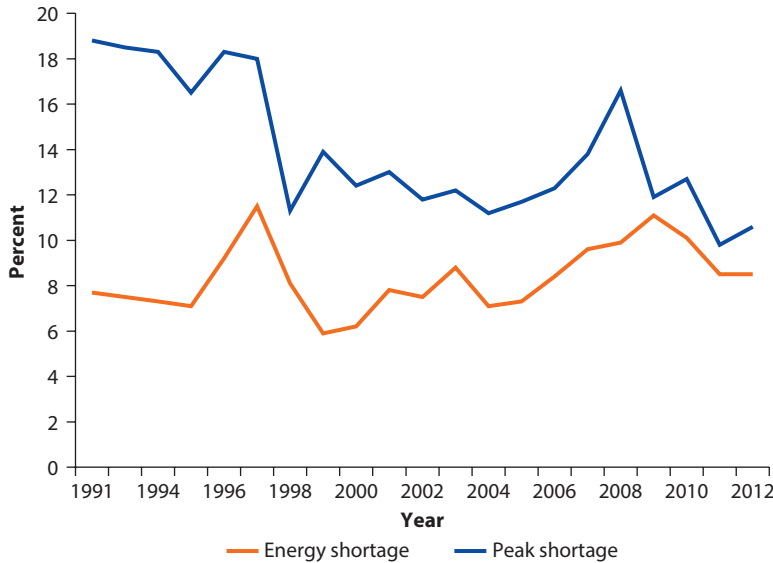
These trends of a growing economy and rapidly expanding population have resulted in a substantial increase in the demand for power. To keep pace with demand, the primary energy supply more than doubled from 1990 to 2010, and consumption rose by almost 200 percent. However, the demand for electricity continues to outstrip supply, and the energy deficit and peak deficit stood at 8.5 percent and 10.6 percent, respectively, for 2011/12 (figure 1.1).

At the time of the 1991 crisis, the power industry comprised 19 SEBs and 6 electricity departments. India had progressed from a meager 1,300 megawatts of installed capacity at independence in 1947 to 7,500 megawatts by 1990. However, the power sector was in poor financial condition and suffered from technical inefficiency. In 1991, revenue recovery was 79 percent. Technical indicators such as transmission and distribution losses were close to 23 percent, and thermal generation inefficiency was high with a plant load factor of only 54 percent. Peak and energy deficits were 7.7 percent and 18.8 percent, respectively. Financial performance was alarming, with losses amounting to roughly Rs 40 billion, excluding subsidies, equivalent to 0.7 percent of GDP. The subsidies, amounting to Rs 75 billion, have long supported the below cost-recovery tariffs charged agriculture and domestic consumers to facilitate cheap power for irrigation to boost food security for the former and to promote availability of electricity at affordable prices for the latter (Sharma, Chandramohan Nair, and Balasubramanian 2005).

The events of the early 1990s set in motion the first phase of the power sector reform agenda, which focused on increasing generation capacity. Realizing that government power plants alone would not be able to meet growing demand, reforms were pushed through to promote private sector participation, unbundle the SEBs, and establish independent regulators to oversee the industry. The Electricity Laws (Amendment) Act allowed private players, including foreign investors, to establish, operate, and maintain electricity generation plants as independent power producers with up to 100 percent ownership and to enter into long-term power purchase agreements with SEBs.

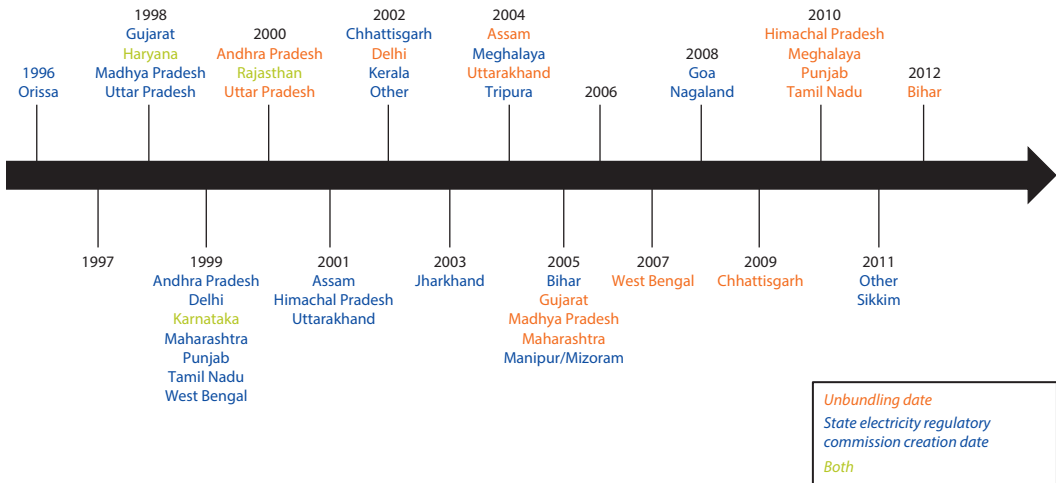
India continued to struggle with crippling power deficits during the 1990s. The nascent state reform process—mainly the unbundling of SEBs and establishing functional regulatory commissions—progressed at a sluggish pace. In 1993, Orissa became the first state in India, and also in South Asia, to pursue fundamental restructuring and privatization of the state power sector, which persuaded Andhra Pradesh, Delhi, Rajasthan, Haryana, Uttar Pradesh, Karnataka, Gujarat, Assam, and Madhya Pradesh to pursue restructuring as well. In addition, the central government mandated the formation of central and state regulatory commissions through the Electricity Regulatory Commission Act of 1998 (figure 1.2).

Figure 1.1 Peak and Energy Deficit



Source: International Energy Agency, CEA.

Figure 1.2 Timeline of Sector Unbundling and Establishment of Regulatory Commissions



Events Leading up to the Electricity Act, 2003

Despite these reform and restructuring efforts, the commercial performance of state utilities continued to deteriorate. By early in the first decade of the 2000s, power sector losses had risen to about Rs 250 billion (\$6.144 billion or 1.5 percent of India's GDP). Technical and operational indicators had also deteriorated since the early 1990s, and cost recovery performance had actually

Table 1.1 Comparative Assessment of Technical and Operational Indicators

	<i>Early 1990s</i>	<i>Early 2000s</i>
Energy deficit (%)	7.7	7.5
Peak deficit (%)	18.8	14.0
Per capita consumption (kWh)	268	355
Transmission and distribution losses (%)	22.8	27.8
Percent share of power sector in total national plan outlay (%)	18.9	12.2
Cost recovery (%)	79.4	68.6
Financial losses (Rs billion)	40	250
Losses as a percentage of GDP	0.7	1.5

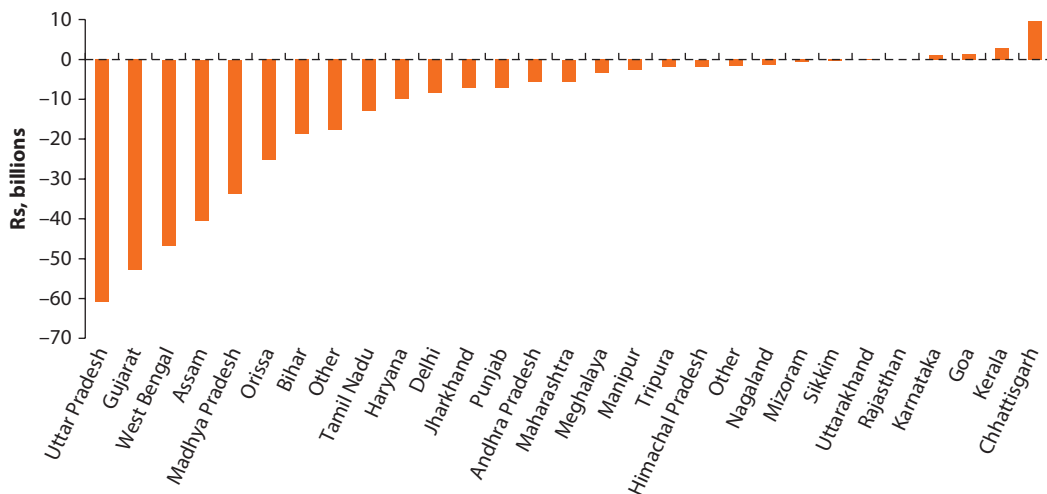
Source: Sharma, Chandramohan Nair, and Balasubramanian 2005.

declined. The substantial energy and peak deficits continued despite impressive capacity additions because demand simply outstripped supply gains. The share of the power sector burden on national plan outlays declined despite rising power sector investments as the result of larger government budgets (table 1.1).

To combat the worrying financial situation, in 2001 an expert committee under the leadership of M. S. Ahluwalia recommended and implemented a bail-out plan for the sector. This bailout was a response to arrears to central public sector undertakings such as National Thermal Power Corporation, Power Grid Corporation of India Limited, and others. The primary component of the bailout was the conversion into state government bonds of about Rs 400 billion in outstanding arrears of the SEBs to the central public sector undertakings to restore the sector to financial solvency. The terms of the bailout included waiving 50 percent of the outstanding interest and converting Rs 350 billion of debt into state government bonds. Thus, a number of states began fiscal 2002/03 with accumulated losses that were lower than in the previous fiscal year: 2002/03 served as the starting point for the reforms that have followed. The total accumulated losses amounted to Rs 351 billion. Only five states started with a balanced budget or profits in the electricity sector—Chhattisgarh, Goa, Karnataka, Kerala, and Rajasthan (figure 1.3). Two-thirds of the accumulated losses were largely concentrated in five states: Assam, Gujarat, Orissa, Uttar Pradesh, and West Bengal.

The Ahluwalia Committee recommended that the utilities pursue reforms and technical improvements to improve their viability. The committee also strongly emphasized the need to link the bailout to incentives to implement reforms. The committee recognized that the arrears were not due to one-off events but rather to the nonviability of the financial and operational model of the utilities.

These recommendations set the stage for the landmark Electricity Act, 2003, and the continuing substantive reform and policy measures put in place in the years since. The act paved the way for delicensing of thermal power generation, introduction of power trading, adoption of multiyear tariff principles, and promotion of rural electrification and renewable energy. The act's most important focus was to move the sector toward enhanced competition, accountability, and commercial viability (box 1.1).

Figure 1.3 Accumulated Losses, by State, 2003

Source: India Power Sector Review Database.

Box 1.1 The Electricity Act, 2003, and Subsequent Policies

A decade of reform measures was consolidated into the landmark Electricity Act, 2003, which replaced the previous laws governing the sector. One of the fundamental goals of the Electricity Act, 2003, was to improve power sector performance and efficiency by establishing a market-based industry structure. The comprehensive act tackles major issues in generation, transmission, distribution, and trading. The reform requirements of the 2003 act were subsequently crystalized into policies such as the National Electricity Policy (2005), Integrated Energy Policy (2005), the Rural Electricity Policy (2006), and the National Tariff Policy (2006). Salient features of the act and subsequent policies are as follows:

1. Introduce Competition

- **Unbundling of the SEBs:** Distribution, generation, transmission, and dispatch functions are required to be independently operated.
- **Delicensing of generation:** The license requirement from CEA to build/operate generation plants was removed (except for hydropower projects above a given threshold, currently Rs 10 billion), making it easier for any generation company to enter the market.
- **Open Access:** State electricity regulatory commission (SERC) must provide a notification of nondiscriminatory open access, which permits the sale of electricity directly to consumers outside of power purchase agreements with distributors, providing choice and network access to power procurers and endusers.
- **Introduction of Power Trading:** Establish ceilings on trading margins to allow trading of electricity. SERCs issue trading license for intrastate trade, while intrastate trading is licensed by the Central Electricity Regulatory Commission (CERC). SERCs must also introduce scheduling discipline into this multiseller market by establishing intrastate availability-based tariffs.

box continues next page

Box 1.1 The Electricity Act, 2003, and Subsequent Policies *(continued)***2. Enhance Accountability and Transparency**

- **Establish State Electricity Regulatory Commissions (SERC):** State power sectors must be independently regulated by SERCs, whose powers and responsibilities include setting tariffs, passing, and in some cases implementing regulations. SERCs are meant to be independent from the state and central governments, though the center will continue to direct national electricity and tariff policy.
- **Establish National Appellate Tribunal:** The central government established this entity to oversee the implementation of reforms throughout the country and address any disputes or appeals against the orders of the Electricity Act.
- **Corporatization of Utilities:** Utilities are required to register as corporate entities, thereby becoming subject to the requirements of the Companies Act.

3. Achieve Cost Recovery and Commercial Viability

- **Improvement in Operational Efficiency:** State utilities are required to achieve 100 percent metering within two years, adopt stringent measures to deter electricity theft, and reduce cross-subsidies in a phased manner.
- **Competitive Procurement:** The Tariff Act (2006) specified that distribution licensees procure long-term power through tariff-based bids under a multiyear tariff framework with a control period of three to five years. Two different procurement modes (Case I and Case II) were developed.
- **Progress Tariff-Setting:** SERCs are required to establish tariff-setting mechanisms to bring tariffs to cost-recovery levels. Ultimately, SERCs should also issue multiyear tariffs to increase pricing certainty.

4. Accomplish Universal Access to Electricity/Rural Electrification

- **Universal Access:** The Rural Electricity Policy (2006) set an ambitious goal of providing electricity for all by 2009 and required state governments to formulate a Rural Electrification Plan within six months of passing the policy.
- **Affordability and Availability:** The Rural Electricity Policy also aimed for high-quality, reliable power available at reasonable rates and a minimum lifeline consumption of 1 kilowatt hour per household per day by 2012.

5. Improve Customer Service and Affordability of Supply

- **Plug Revenue Leakages:** Meet aggregate technical and commercial reduction targets set by SERC in order to reduce retail tariffs.
- **Establish and Maintain Service Standards:** Establish and enforce standards of performance. Establish consumer grievance redressal forum (CGRF) and appoint an ombudsman.

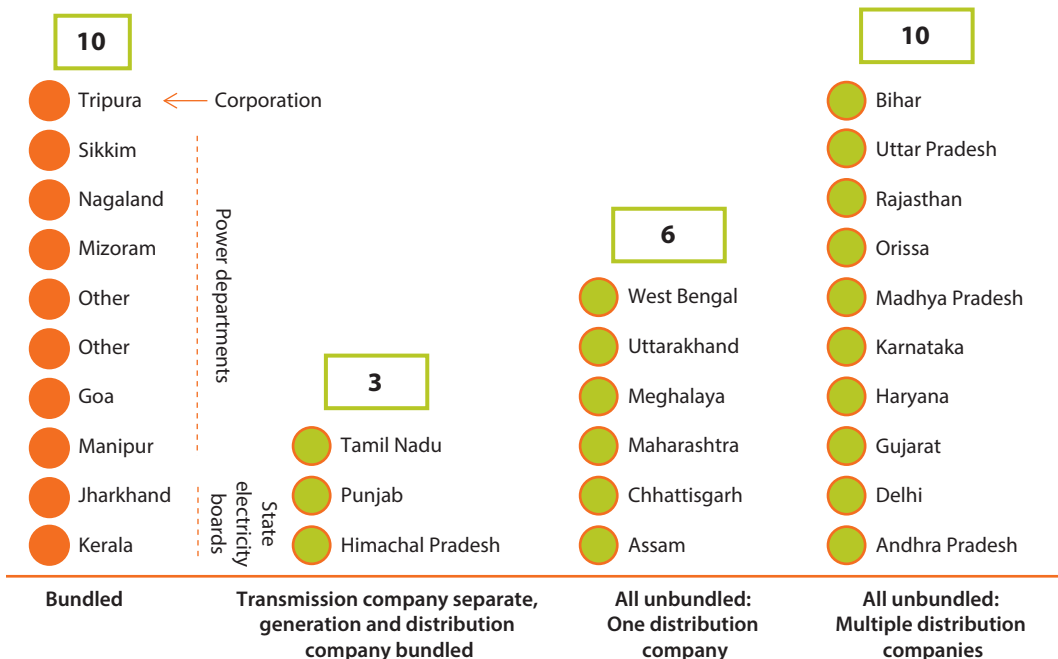
6. Promote Renewable Energy/Energy Efficiency Initiatives

- **Renewable Energy Framework:** SERCs are required to specify a percentage of overall purchases from renewable sources for the distribution licensee(s) in their states. This renewable purchase obligation (RPO) guarantees a minimum percentage of renewables in the state's energy consumption mix.
- **Incentives to Promote Renewables Energy Generation and Energy Efficiency:** Notification of regulations on renewable energy and energy efficiency, including feed-in tariffs, time-of-day tariffs, and time-of-day metering.

To fulfill the directive in Section 3 of the Electricity Act, 2003, and as an extension of the National Electricity Policy (2005), the central government in 2006 established the National Tariff Policy (NTP). The policy focuses on tariff-setting issues such as a return on investment for power generators and suppliers, ensuring reasonable consumer charges, and setting standards for charging depreciation and the cost of debt. It also sets a benchmark for reduction in cross-subsidies: By 2011/12, tariffs were to be within ± 20 percent of the average cost of supply for all consumer segments. It also provides tariff determination guidelines for SERCs, specifically the requirement for multiyear tariffs. Other important topics covered are methods for calculating cross-subsidies under open access and the structure of competitive bidding for private participants. For the power generation segment, the National Tariff Policy addresses the possibility of implementing separate capacity for peak demand and differential rates for peak and nonpeak loads. Overall, the policy aims to improve efficiency and transparency in the power sector and to ensure that those efficiency gains are passed on to consumers—but specifics with regard to methodology and timeframe are mainly left to the Forum of Regulators to develop.¹

The Electricity Act, 2003, fundamentally altered the institutional arrangements in the power sector. As of 2013, 28 regulatory commissions were functional; the last ones became operational in 2011. The states of Manipur and Mizoram share one joint regulator. The unbundling process is complete for 18 states, and in 11 states the sector operates either as a corporation, a department, or an SEB (figure 1.4). The states that proceeded with reforms have diverse market structures: Nine states have unbundled into multiple distribution

Figure 1.4 Power Sector Structure, by State



companies, six have unbundled into only one distribution company, and three states have separated transmission but retain bundled generation and distribution. These latter three states all went through the unbundling process in 2010.

The Electricity Act, 2003 (and subsequent government policies articulated in the National Electricity Policy, 2005, and Integrated Energy Policy, 2006) brought a sharp focus on market reform. Even though power trading predated the act, the recognition of trading as a licensed activity gave it official status that has helped develop competitive power markets. Simultaneously, the use of the frequency-linked unscheduled interchange (UI) mechanism was adopted in 2000 with a balancing market creating a wholesale transaction platform.² CERC has further pushed market reform through institution of two power exchanges. Although the traded volume on the power exchanges as a percentage of total flows is not large, revenue from exchange trades has played an important role in sector reforms and investment signaling. In contrast, retail markets have seen only tepid growth. The act does not provide for a multisupplier regime, except through open access. This factor distinguishes India from other competitive electricity markets in which wholesale market reforms have been accompanied or followed by very structured retail market reforms.

The Indian market reforms are predicated on open access to transmission and distribution networks. The Electricity Act defines open access as “non-discriminatory provision for the use of transmission lines or distribution system or associated facilities with such lines or system by any licensee or consumer or a person engaged in generation in accordance with the regulation specified by the Appropriate Commission.” Several state regulatory commissions have formulated regulations on open access. Nevertheless, implementation of open access in India remains poor. Several states have not established open access regulations for certain categories of consumers (usually those above 1 megawatt). As of fiscal year 2011, 22 states had issued notification of open access regulations, 20 had determined surcharges, 17 had determined wheeling charges, and 22 had determined transmission charges.

CERC has also promoted competitive markets in renewables through the Renewable Energy Certificate mechanism. Although in its infancy, the Renewable Energy Certificate mechanism has generally been acknowledged as a positive market development measure.

Accelerated Power Development and Reforms Program

Recognizing the importance of a robust distribution sector, the central government introduced a major investment scheme in 2000–01 called the Accelerated Power Development Programme. It was followed in 2003 by a more incentive-based program called the Accelerated Power Development and Reform Programme (APDRP), which followed the recommendations of the 2001

Ahluwalia bailout package. The APDRP's goals focused on (1) improving financial viability, (2) reduction of aggregate technical and commercial (AT&C) losses to about 15 percent, (3) improving customer satisfaction, (4) increasing the reliability of power supply, (5) improving the quality of power supply, (6) adopting a systems approach to management information systems, and (7) improving transparency through computerization.³

Implementation of the APDRP was reviewed by the Abraham Committee (appendix B).⁴ The committee noted that program adoption was less than ideal, although some utilities have managed to reduce their AT&C losses and improved the quality of supply. The success of APDRP was limited largely because of a poor response from the states, delays in transfers of funds by the states, unrealistic detailed project reports (DPRs), and employee resistance to outsourcing, among other factors. The Abraham Committee therefore suggested that APDRP should continue in the 11th five-year plan but with certain improvements geared toward better planning and project management, direct release of funds to utilities, flexibility in DPRs, and setting of realistic targets. The scheme was modified during the 11th Plan as the Restructured APDRP (R-APDRP) with a total outlay of Rs 515 billion with the aim of restoring the commercial viability of the distribution sector by using appropriate mechanisms to substantially reduce the AT&C losses to a level of 15 percent. States reporting AT&C losses higher than 30 percent will reduce losses at the rate of 3 percent a year, and the states reporting AT&C losses of less than 30 percent will reduce them at the rate of 1.5 percent a year. The R-APDRP addressed the issue of building baseline data, including meter data acquisition, under Part A. After ascertaining AT&C losses, the issue of power system upgrade and modernization is taken up under Part B. R-APDRP focuses on reduction of AT&C losses in urban areas (towns and cities with populations of at least 30,000). To provide incentives to states, R-APDRP will convert loans into grants under Part B.

Notes

1. See http://www.forumofregulators.gov.in/About_FOR.aspx.
2. UI is a mechanism established to support grid discipline and grid efficiency by imposing charges on those who deviate from scheduled injection or drawl. UI charges is one of the three-part tariff of Availability-Based Tariff (ABT) set up in 2000. http://powermin.gov.in/distribution/availability_based_tariff.htm.
3. See http://www.apdrp.gov.in/Forms/Know_More.aspx.
4. See http://www.powermin.nic.in/whats_new/pdf/Report%20on%20Restructuring%20of%20APDRP.pdf.

References

- Bajaj, H. L., and D. Sharma. 2006. *Power Sector Reforms in India*. New Delhi: Government of India. <http://www.worldenergy.org/documents/p001438.doc>.
- Panda, Aurobinda, and Atul Patel. 2011. "Competition Law and Competition Issues Affecting the Energy Sector in India." *Journal of Infrastructure Development* 3 (2): 107–15. <http://ssrn.com/abstract=1873084.21>.
- Sharma, D. Parameswara, P. S. Chandramohan Nair, and R. Balasubramanian. 2005. "Performance of Indian Power Sector during a Decade under Restructuring: A Critique." *Energy Policy* 33 (4): 563–76. <http://eprint.iitd.ac.in:8080/handle/2074/1478/1/sharmaper2005.pdf>.

Deteriorating Sector Finances

This chapter traces the evolution of the industry since passage of the Electricity Act, 2003, providing a background for understanding its current financial performance issues. The chapter focuses on the distribution segment as a critical part of the sector's value chain. Distribution companies are responsible for securing revenues that could be pumped back into the sector for expansion and modernization, making the segment financially viable and self-sustaining. Finally, the chapter identifies which states have emerged as good performers and those that have experienced deteriorating sector finances.

A Snapshot of Sector Finances

Utility finances have continued to worsen considerably on a year-to-year basis, reaching a point that has been termed as “India’s subprime crisis.” The crisis has compounded since 2006, reaching mammoth losses on the order of Rs 618 billion (\$14 billion) equivalent to 0.7 percent of India’s gross domestic product (GDP) and 17 percent of gross fiscal deficit in 2011. The opportunity cost of these losses is huge. Compared with the 11th Plan outlay in different sectors, the losses corresponded to 44 percent of health care spending or nearly 23 percent of education spending.

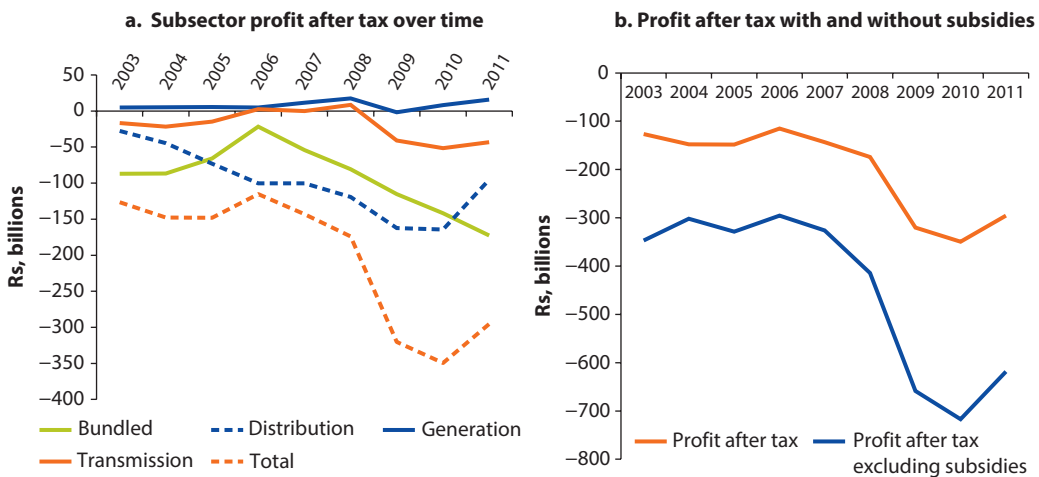
Profit after tax (PAT) includes subsidies by several state governments, primarily to the distribution segment. Many utilities book subsidies to cover lower-than-cost-recovery tariffs charged to agriculture and domestic consumers to accommodate the equity and political objectives of energy access. These subsidies are booked as part of revenues on the basis of the subsidy allowed by the State Electricity Regulatory Commissions. State government either pays part or all of the subsidy booked by the distribution companies based on the SERC recommendation, which means that state utilities can continue to report large deficits even after receiving subsidies. The subsidy figure and the corresponding loss figures are adjusted in the next year’s balance sheet if the actual subsidy received is lower than the subsidy booked.

The total subsidies booked in 2011 were Rs 323 billion (\$7 billion), and PAT adjusted for subsidies booked was Rs (-) 295 billion (\$6.5 billion) in 2011. Losses with subsidies, though they accounted for only 0.3 percent of India’s GDP in 2011, were nevertheless equivalent to the GDP of Rwanda, Tajikistan, or Kosovo in 2011. These losses are overwhelmingly borne by the bundled State electricity boards (SEBs) and the unbundled distribution companies. The upstream generation segment recorded a small profit of Rs 15 billion (\$344 million) (figure 2.1).

The bundled states have been on a downward slide from 2006 onward, with only Kerala registering profits in 2011. The generation segment has been profitable every year except for miniscule losses in 2009. Aside from three generating companies in Chhattisgarh, Madhya Pradesh, and Rajasthan, the remaining 12 reported profits in 2011. The transmission segment had become profitable in the mid-2000s and then slid back into large losses in the latter part of 2000s. However, these losses were mainly in Uttar Pradesh, because the remaining 14 state transmission companies made either profits or relatively small losses (figure 2.2). Finally, the distribution segment recovered slightly in 2011 after experiencing serious losses. Delhi has by far the most profitable distribution sector, registering profits of Rs 8 billion in 2011. This segment, which underpins the sector, is also symptomatic of the weaknesses of the sector. Among the unbundled distribution companies and SEBs, only nine states experienced an upside in distribution finances between 2003 and 2011 in real terms.

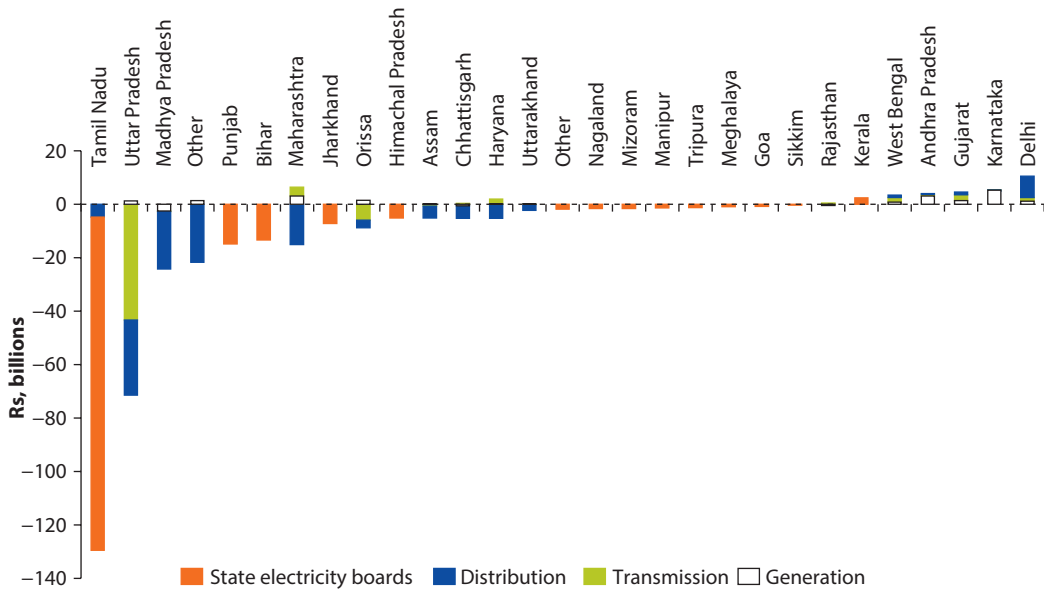
Accumulated losses for the sector stood at Rs 350 billion in 2003 and rose to Rs 1,146 billion by 2011, doubling when adjusted for inflation. The losses have grown at a compound annual growth rate (CAGR) of 9 percent in real terms since 2003. The share of these losses in GDP has remained stable at 1.3 percent, because the economy has also grown more than fivefold since 2003.

Figure 2.1 Profit (Loss) after Tax, 2003–11



Source: India Power Sector Review Database.

Figure 2.2 Profit (Loss) after Tax, by State, 2011



Source: India Power Sector Review Database.

Together, distribution companies and bundled utilities (SEBs and power departments) are by far the largest contributors to the accumulated losses, though their share has fluctuated, falling from 90 percent in 2003 to 79 percent in 2008 and then rising to 86 percent in 2011. Between 2003 and 2011 the accumulated losses of distribution companies grew by 31 percent annually in real terms. The transmission companies account for most of the remaining losses, since generation is the only segment with profits or small losses since 2003, with all other segments showed continually growing losses. Distribution is the foundation of the sector value chain because the distribution companies face the consumers: any failure to collect sufficient revenue to meet expenses creates ripple effects that cascade up the entire chain.

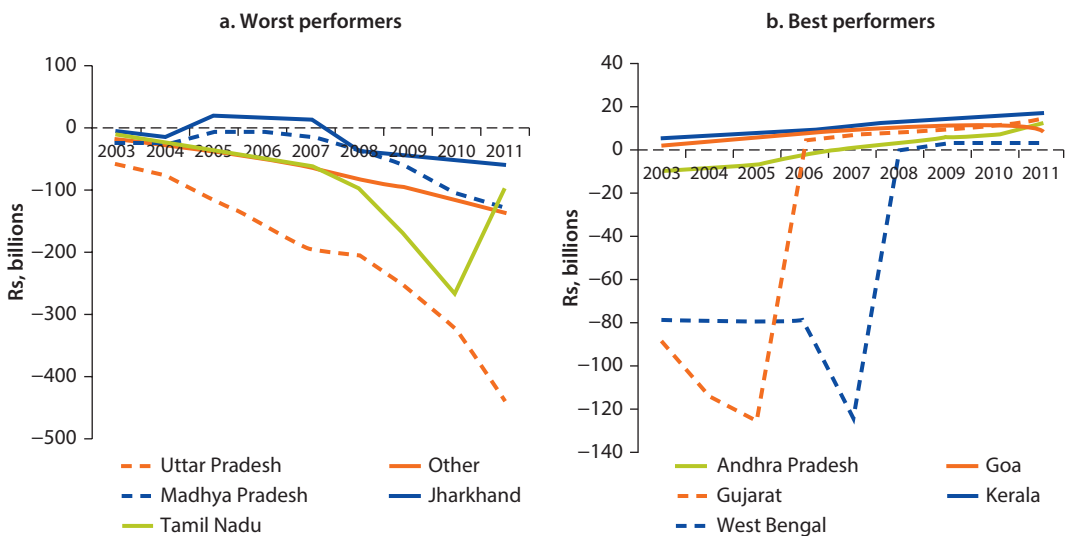
The accumulated losses are concentrated in a few states and are equivalent to a substantial part of their state GDP. Uttar Pradesh has remained in a free-fall situation since 2003 and alone accounted for close to 40 percent of total accumulated losses in 2011, followed by states such as Madhya Pradesh, Tamil Nadu, and Jharkhand. These four states account for an upward of 60 percent of India’s total accumulated losses. For North-East states such as Manipur, Mizoram, and Nagaland, the accumulated losses in 2011 were equivalent to 14, 12, and 8 percent of state GDP, respectively. Only in Maharashtra, Delhi, and Karnataka were losses equivalent to less than 1 percent of state GDP.

Despite the overall losses, five states—Kerala, Gujarat, Andhra Pradesh, Goa, and West Bengal—reported accumulated profits of Rs 58 billion in 2011. Gujarat and West Bengal are credited with dramatic turnarounds as they transition from large accumulated losses to a robust financial situation.

Gujarat and Uttar Pradesh have followed dramatically opposite performance trajectories since 2003, when their accumulated losses were similar. Gujarat went on to record the second highest accumulated profits in 2011. Aside from Gujarat, Andhra Pradesh and West Bengal transitioned from losses to profits in the mid-2000s. The most profitable power sector in the country is in Kerala (figure 2.3). Despite remaining a bundled utility, Kerala is the only state that has consistently reported accumulated profits since 2003. Goa has achieved similar results.

The sector’s accumulated losses mask the strengths and weaknesses of individual segments in the value chain as well as variety of experiences among states. Of the states with unbundled segments, only two, Andhra Pradesh and Gujarat, have accumulated profits in all three segments. Three states, Assam, Madhya Pradesh, and Uttar Pradesh, register losses across the entire sector. The other states have distinct segments of the value chain that are profitable. Particularly noteworthy is Rajasthan, which has unprofitable generation and transmission segments, but whose distribution segment has a balanced budget due to subsidies booked by the utilities. Similarly, in Uttarakhand, generation is unprofitable but transmission and distribution are profitable. The worst loss-making states in the generation segment are Madhya Pradesh, Uttar Pradesh, Rajasthan, Chhattisgarh, and Haryana. In the transmission segment, the worst losses are in Uttar Pradesh, Delhi, Rajasthan, Tamil Nadu, and Orissa, and in the distribution segment the worst losses are in Uttar Pradesh, Madhya Pradesh, Haryana, and Maharashtra. Among the states with bundled segments, only Goa and Kerala report profits, with the remaining 10 recording losses (table 2.1).

Figure 2.3 Accumulated Losses, by State, 2003–11



Source: India Power Sector Review Database.

Table 2.1 Accumulated Losses across the Power Sector Value Chain, 2011

<i>Unbundled sector</i>		<i>Bundled sector</i>	
G, T, and D unprofitable	Andhra Pradesh, Gujarat	Profitable	Goa, Kerala
G, T, and D unprofitable	Assam, Madhya Pradesh, Uttar Pradesh	G, T, and D unprofitable	Bihar, Himachal Pradesh, Jharkhand, Manipur, Mizoram, Meghalaya, Nagaland, Punjab, Tripura
G and T unprofitable, D profitable	Rajasthan, West Bengal		
G and D profitable; T unprofitable	Delhi, Tamil Nadu		
G unprofitable; T and D profitable	Uttarakhand		
T profitable, G and D unprofitable	Haryana, Chhattisgarh		
G and T profitable, D unprofitable	Maharashtra, Karnataka		
Total losses (Rs billion)	89.631	Total losses (Rs billion)	24.993
Total accumulated losses: Rs 114.624 billion			

Source: India Power Sector Review Database.

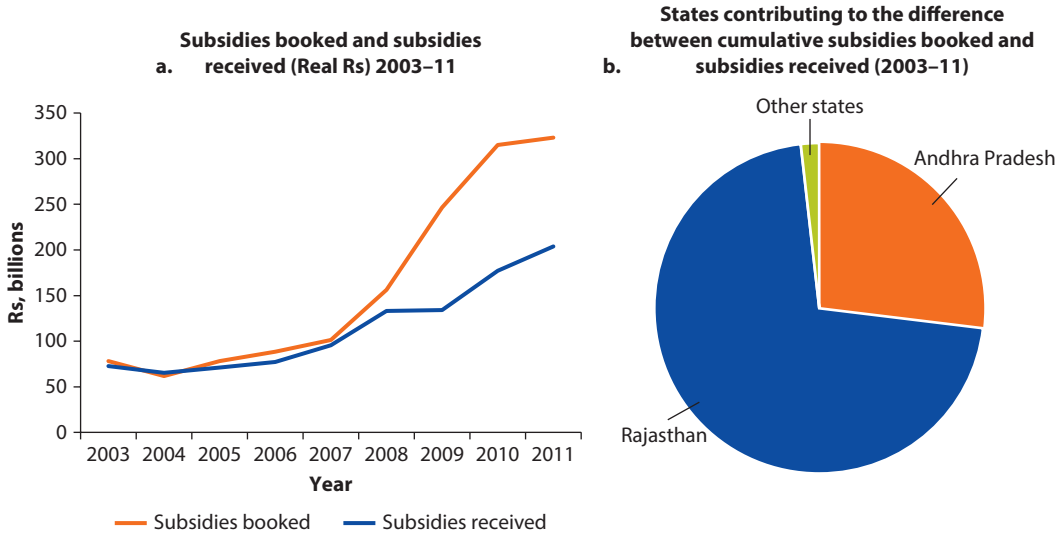
Note: G = generating segment; T = transmission segment; D = distribution segment.

Subsidies are not universal: 13 states had not booked subsidies in 2011 and reported losses. Among the 16 states that booked subsidies, three reported profits and the remaining states made losses. Among the states with profitable distribution sectors, Andhra Pradesh, Gujarat, Karnataka, and Rajasthan were profitable after subsidies from their respective state governments. Only Delhi, Kerala, and West Bengal reported profits excluding subsidies in 2011 (figure 2.4a).

The amount of subsidy encompasses a wide range—from Rs 130 million in Meghalaya to more than Rs 100 billion in Rajasthan in 2011. In five states—Rajasthan, Uttar Pradesh, Haryana, Punjab, and Andhra Pradesh—the subsidies booked amount to more than Rs 20 billion. In the case of Rajasthan, subsidies were equivalent to 3 percent of state GDP in 2011. Subsidies to the power sector are therefore not trivial items in state budgets.

However, subsidy booked and subsidy received can vary, contributing further to state utilities' losses. On an average, the subsidies booked have risen annually by 12 percent, and subsidies received have grown by 7 percent annually since 2003. However, the divergence becomes noticeable only from 2008 onward. Rajasthan and Andhra Pradesh account for 95 percent of the difference between booked and received subsidies. In other states, the difference between booked and received subsidies is relatively minor. The total cumulative subsidies booked and received between 2003 and 2011 are Rs 1,496 billion and Rs 1,044 billion, respectively. Rajasthan, followed by Andhra Pradesh, Punjab, and Haryana, show cumulative booked subsidies (figure 2.4b).

Figure 2.4 Evolution of Subsidies, 2003–11



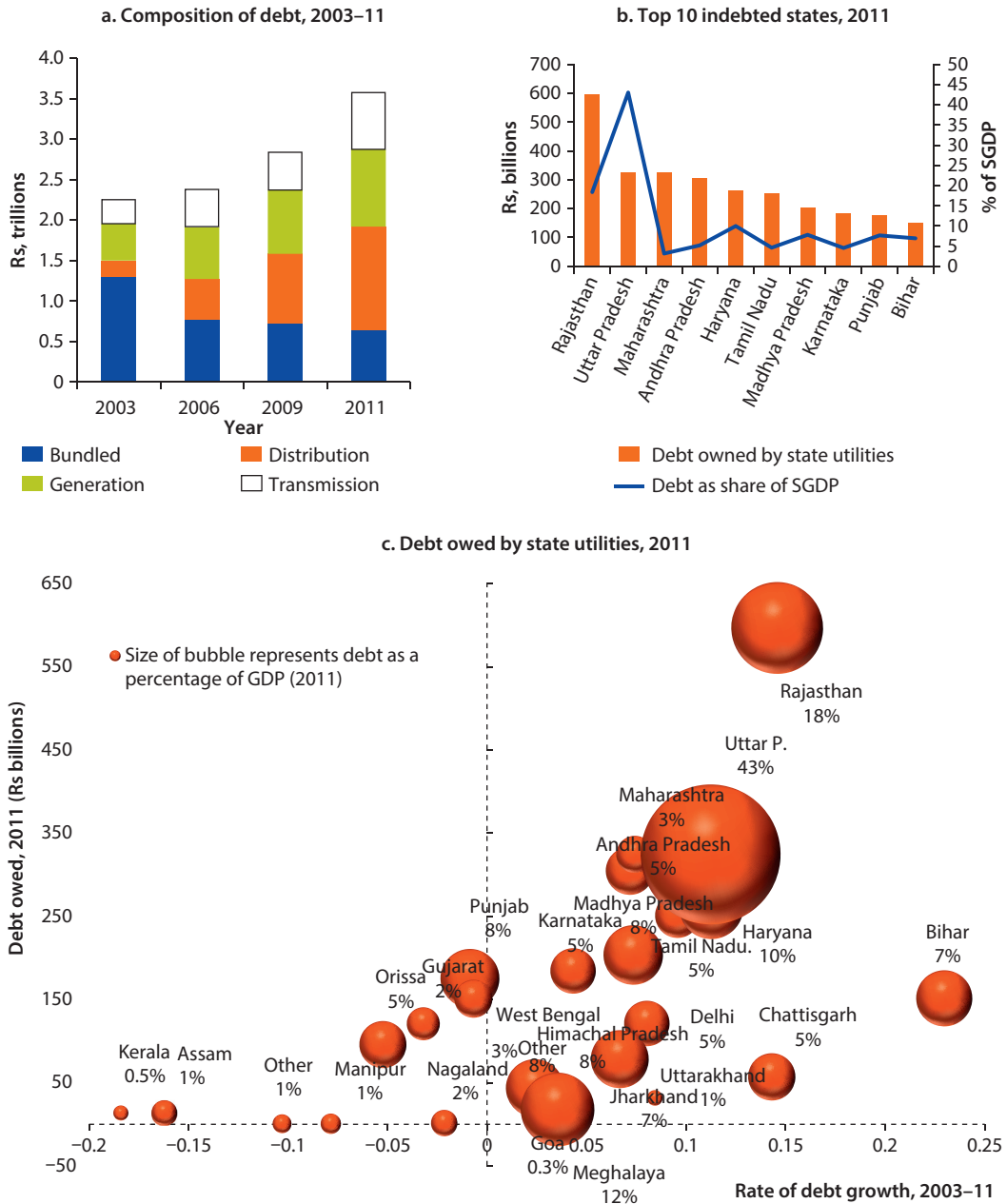
Source: India Power Sector Review Database.

Substantial borrowings by all segments have underpinned the industry’s dramatic expansion. From 2003 to 2011, the distribution segment’s debt grew the fastest, 23 percent in real terms, followed by the transmission and generation segments at 10 and 9 percent, respectively. Debt in bundled utilities has declined, particularly in recent years as more states have unbundled the power sector, and their debt was transferred to the newly created utilities.

The composition of debt among the utilities has also evolved. In 2003, bundled and generation companies accounted for about 78 percent of the total debt of the power sector. This picture had changed dramatically by 2011, when distribution utilities accounted for the largest share, 36 percent, followed by generation and transmission utilities.

Total power sector debt corresponded to 5 percent of India’s GDP in 2011, but a few large states account for most of it. In Uttar Pradesh, Rajasthan, Meghalaya, and Haryana, power sector debt is equal to more than 10 percent of the state GDP. Uttar Pradesh, however, is at an extreme end, with power sector debt equivalent to 43 percent of state’s GDP. Just 10 states together accounted for about 78 percent of India’s Rs 3.5 trillion in power sector debt in 2011. Rajasthan has the largest debt, which grew at a phenomenal rate of 15 percent in real terms between 2003 and 2011. Only Bihar’s debt grew faster, but it started from a lower base. The borrowing profiles of Uttar Pradesh, Haryana, and Tamil Nadu have also evolved dramatically since 2003 (figure 2.5).

Figure 2.5 Debt in the Power Sector



Source: India Power Sector Review Database.
 Note: SGDP = state gross domestic product.

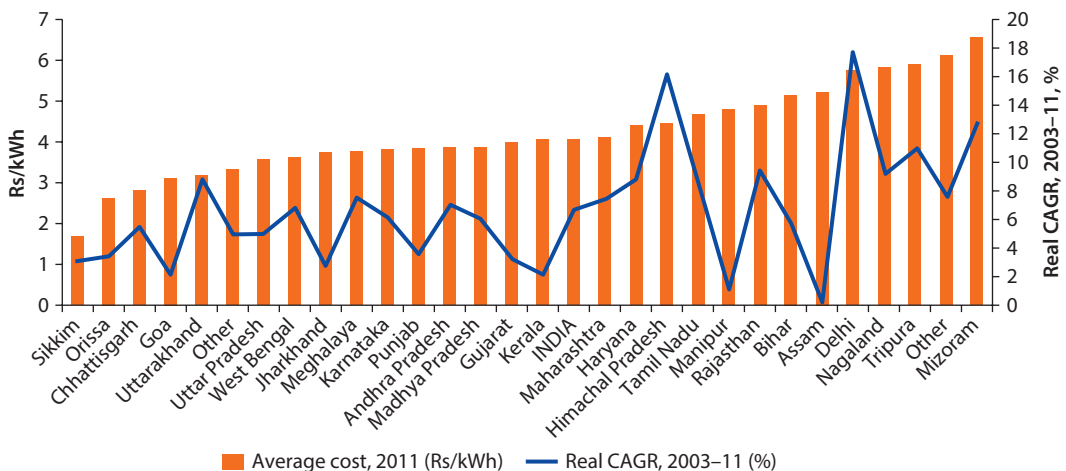
Cost and Revenue in the Distribution Segment

Costs and revenues manifest themselves at the end of the power sector value chain in distribution. The distribution segment is the industry’s interface with customers and recoups the revenue to pay for electric power supply. Analyzing cost and revenue trends separately can identify the underlying causes behind the industry’s burgeoning losses.

Costs: Across India, the average total cost for power distribution in 2011 is Rs 4.06 per kilowatt hour. In addition to Bihar, Delhi, and Rajasthan, many of the North-East states have relatively high cost profiles. At the other end are Chhattisgarh, Orissa, and Sikkim, which report costs of less than Rs 3 per kilowatt hour. The average total cost has risen about 7 percent in real terms since 2003. Assam is the only state in which costs have kept pace with inflation. Several states experienced dramatic growth in costs, with Delhi and Himachal Pradesh at 18 percent.

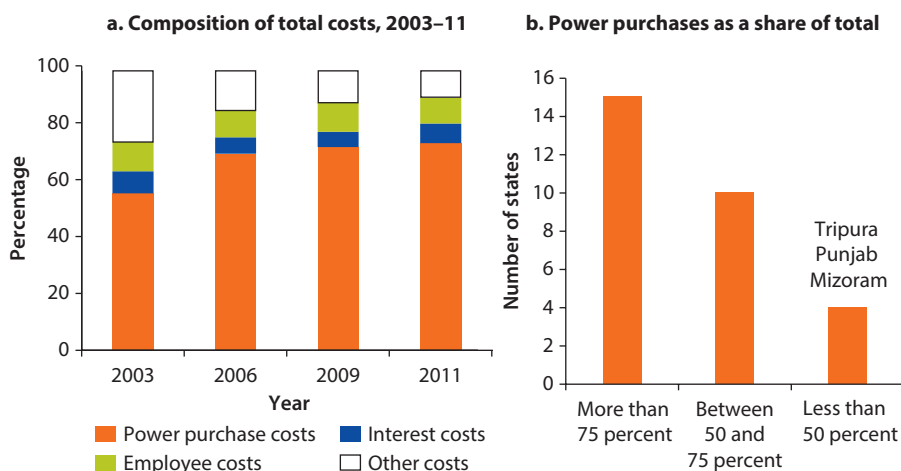
Power purchases are the most important cost component for the distribution segment. The cost of power supplies climbed from 20 percent of total costs in 2003 to 74 percent in 2011 (figure 2.6). Power purchase costs rose considerably each year during this period, and from 2009 onward have accounted for more than half of total costs (figure 2.7). Employee costs and interest payments are also substantial contributors to total costs. The Sixth Pay Commission’s mandated increases resulted in a one-time spike in 2009 in employee costs following implementation of new pay scales for civil servants in India. Employee costs have moderated slightly since then. Interest payments represented 7 percent of total costs in 2011, approximately the same as in 2003. Interest costs declined between 2003 and 2006, but have since risen.

Figure 2.6 Analysis of Average Cost, 2011, and Compound Annual Growth Rate, 2003–11



Source: India Power Sector Review Database.

Note: CAGR = Compounded annual growth rate; kWh = kilowatt hour.

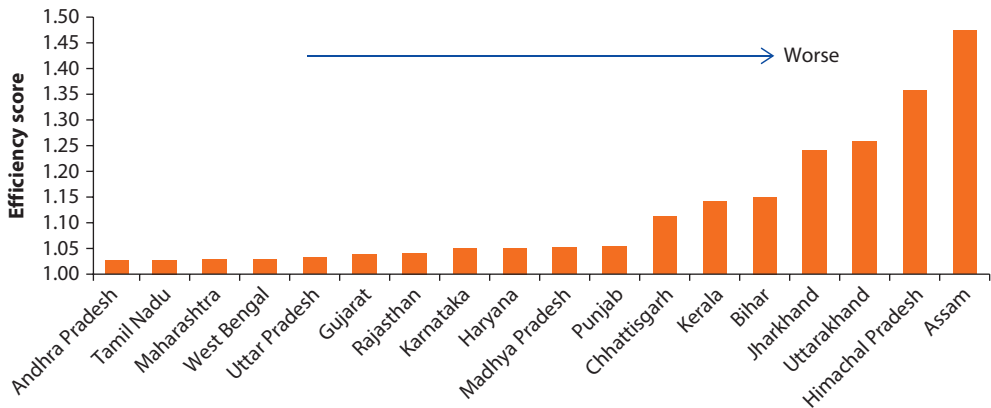
Figure 2.7 Composition of Total Costs, 2003–11

Source: India Power Sector Review Database.

Power purchases as a share of total costs vary from about Rs 1 per kilowatt hour in Sikkim to Rs 4.7 per kilowatt hour in Delhi.¹ The share is contingent on the state's generation capacity and its dependence on purchased power. In eight states, power purchases account for more than 80 percent of total costs, with the highest share in Gujarat at 89 percent. In these eight states, any fluctuations in power procurement prices and volumes have substantial implications for overall cost structures. At the other end is Tripura, where power procurement is only 31 percent of total costs.

Power purchase costs may be different in an absolute sense, but when controlled for hydrothermal mix, share of purchases from outside the state, and power purchase costs per unit (from outside the state), efficiency in terms of power purchase costs could be computed using a stochastic frontier analysis (SFA) in selected states (elaborated in chapter 4). This is essentially an estimate of the cost function. Unity represents efficiency, and the higher the score the more inefficient the utility. Thus, in this model the states with high scores are the most inefficient. They are Assam, Bihar, Himachal Pradesh, Jharkhand, and Uttarakhand (figure 2.8).

Power purchase costs are sensitive to the amount of power purchased outside the state, which is typically more expensive. Bihar and Jharkhand are inefficient because the state-owned generators in those states are inefficient and have extremely low plant load factors. They therefore rely heavily on outside power purchases, adding to their power purchase costs. Assam faces an energy deficit of about 8 percent and has not tied up enough supply through long-term contracts. To meet demand, the state buys power through bilateral transactions and on power exchanges. During fiscal year 2009/10, the share of power procured through traders and exchanges was about 24 percent of total energy consumed.

Figure 2.8 Power Purchase Efficiency Scores

Source: AF-Mercados EMI analysis.

A favorable hydrothermal mix is usually advantageous for the state. Both Himachal Pradesh and Uttarakhand have a high percentage of hydro resources, which usually are low on production during winter months and when the monsoon is delayed. During such times, these states enter into short-term contracts, usually at high prices, and this leads to inefficiency in power purchase costs. As a result, these states have been unable to capitalize fully on their possession of hydro resources.

States should ideally have a plan that includes a clear strategy for power procurement. But states do not have power procurement plans—that is, the percentages to be purchased in long-term, medium-term, and short-term markets, based on their projected demand and load duration curves. This has resulted in states regularly purchasing electricity at high prices in short-term markets or through unscheduled interchange,² or resorting to load shedding. Tamil Nadu, for example, sheds approximately 3,000 to 4,000 megawatts when neither wind nor hydropower is available. Certain states, such as Andhra Pradesh, purchase power at exorbitant prices in short-term markets. Other states, such as Haryana, Punjab, Uttarakhand, and Uttar Pradesh, resort to heavy unscheduled interchange (UI). Unfortunately, the UI mechanism no longer serves its purpose. Certain states do not even pay the UI charges and are involved in legal disputes with Central Electricity Regulatory Commission (CERC) on the issue. Two issues are involved: (1) nonpayment of UI charges removes the fear of being penalized for overdrawn from the grid; and (2) the states do not plan their power purchases in advance. It may not always be possible to have a favorable in-state mix of resources; however, states can enter into long-term contracts to achieve an efficient power procurement cost.

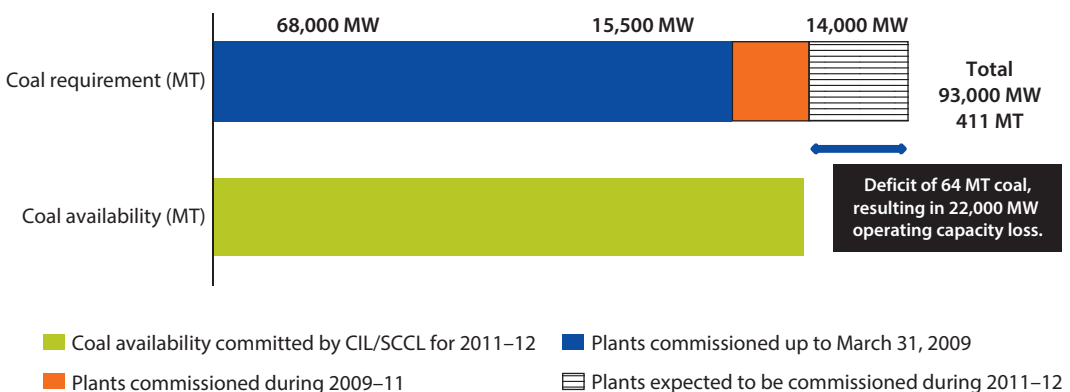
The main driver of rising power purchase costs has been the increase in fuel costs. The market structure for coal does little to promote competitive prices. Coal India Limited is practically a monopoly supplier of coal, producing more than

80 percent of domestic coal, and it is allowed to set its own prices. Furthermore, the demand-supply gap for domestic coal has been growing. In India, more than 70 percent of base load power supply comes from coal-fired power plants.³ Coal India Limited (CIL) has not been able to increase production to meet demand. During the 11th Plan period (2007–12), coal-based power capacity increased by 9.5 percent annually, from 68 gigawatts to 112 gigawatts. During the same period, coal production only increased 5 percent per year. In 2012, the difference was much starker—installed coal-based capacity increased by 20 percent, whereas domestic coal production increased by only 1.4 percent. Consequently, 37 gigawatts of capacity was stranded in 2012 (figure 2.9), and uncertainty about long-term fuel supplies constrains new investment in power generation.

The result has been fuel shortages. Between 2009 and 2011, CIL failed to supply 54 million tons of coal that it had contracted to supply to power producers. This production shortfall has contributed to a sharp increase in imported coal, which is two to three times more expensive, and to the increased use of e-auctions by power producers to purchase coal. Imports have increased from 10 million tons in 2008 to 45 million tons in 2012, and they are expected to rise to 159 million tons by 2017. The e-auction mechanism was originally intended to make coal available for small to medium producers, yet 35 million tons of coal was sold in 2012, with many power producers buying coal through this more costly route, even as CIL met neither its fuel supply agreements nor coal production targets.⁴

In addition to power procurement costs, interest costs are also trended upward. In recent years, capital costs for distribution companies have increased in several states. Together, six states—Andhra Pradesh, Haryana, Madhya Pradesh, Punjab, Rajasthan, and Tamil Nadu—account for 59 percent of the interest costs incurred between 2009 and 2011. For Bihar, Jharkhand, Punjab, Rajasthan, and Tamil Nadu, interest costs were more than 10 percent of total average power production costs in 2011.

Figure 2.9 Energy Deficit Caused by Coal Shortages, 2012



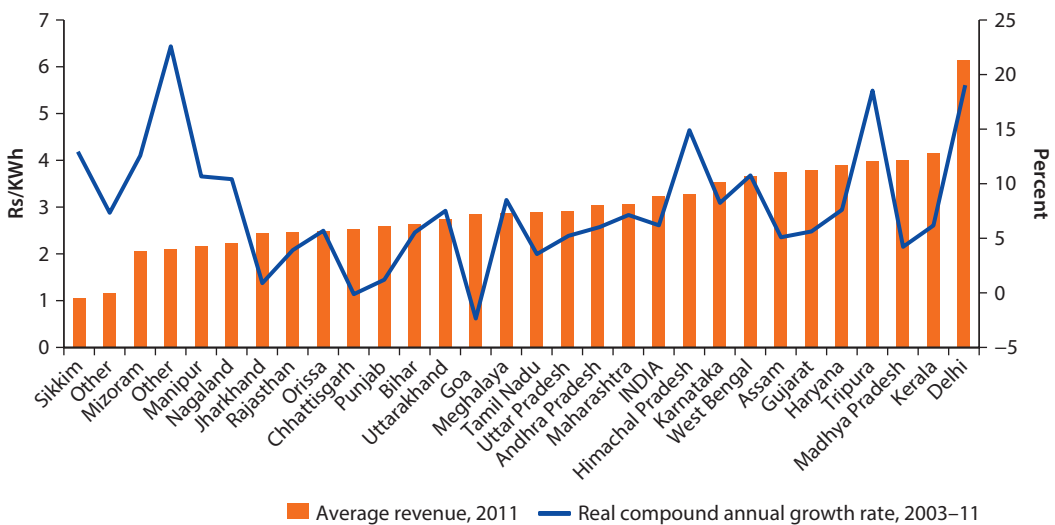
Source: Central Electricity Authority (CEA).

Note: CIL = Coal India Limited; SCCL = Singareni Collieries Company Limited.

This increase in interest costs is due to increased borrowing by distribution companies for working capital. Normally, the regulator permits distribution companies to borrow only to meet their capital investment needs. In recent years, however, many distribution companies have been forced to borrow to meet operating expenses because of their negative cash flows. Therefore, the debts of distribution companies have grown considerably larger, but these financial liabilities have not gone toward asset creation. Because the loans supplemented working capital, the utilities have not been able to recover the interest costs through tariff increases, further eroding their profitability. The capital structure of most distribution companies is therefore highly tilted toward debt. On average, state utilities have a debt-to-capital ratio of 77 percent, and many state utilities have no equity. This high degree of leverage greatly increases the sector's credit risk profile and is highly unsuitable for the utility business from an efficiency perspective.

Revenues: The average collected revenue (without subsidy) per unit of input energy stands at Rs 3.23 per kilowatt hour. Delhi collects the highest, at Rs 6 per kilowatt hour, while a group of North-East states is at the lower end (figure 2.10). Revenues grew annually in real terms by about 6 percent between 2003 and 2011. Goa is the only state in which revenue growth was negative. The other top performers, Delhi and Tripura, grew at a 19 percent annual rate. The growth rate for a majority of the states was less than 10 percent (figure 2.10). These revenues are a product of energy sold and tariffs. Energy sold is a parameter largely under the control of utilities, whereas tariffs are set by the regulator, which is an external stakeholder in the power sector operating environment.

Figure 2.10 Revenues in 2011 and Compound Annual Growth Rate



Source: India Power Sector Review Database.

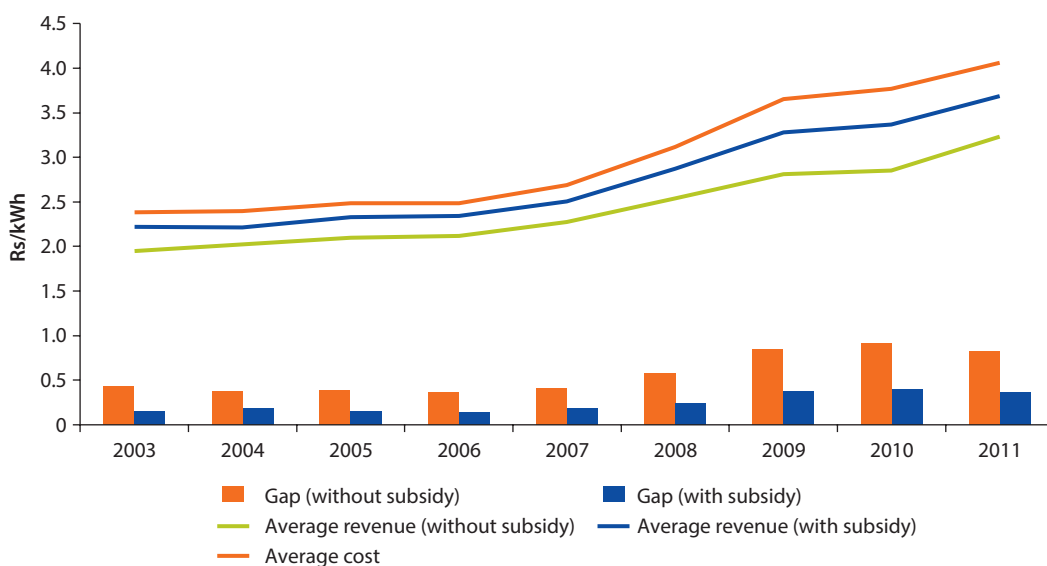
The Gap between Cost and Revenue

Losses stem from the gap between average cost and average revenue. On a per-unit basis, cost recovery performance fluctuated throughout 2003–11 but remained within a band of 76 to 85 percent and averaged 82 percent (figure 2.11). Between 2003 and 2007, cost recovery rose because revenues rose faster than costs in real terms. However, cost recovery declined sharply during 2008–10 to a low of 76 percent and rose in 2011 to 80 percent. The gap between costs and revenues was thus 20 percent in 2011.

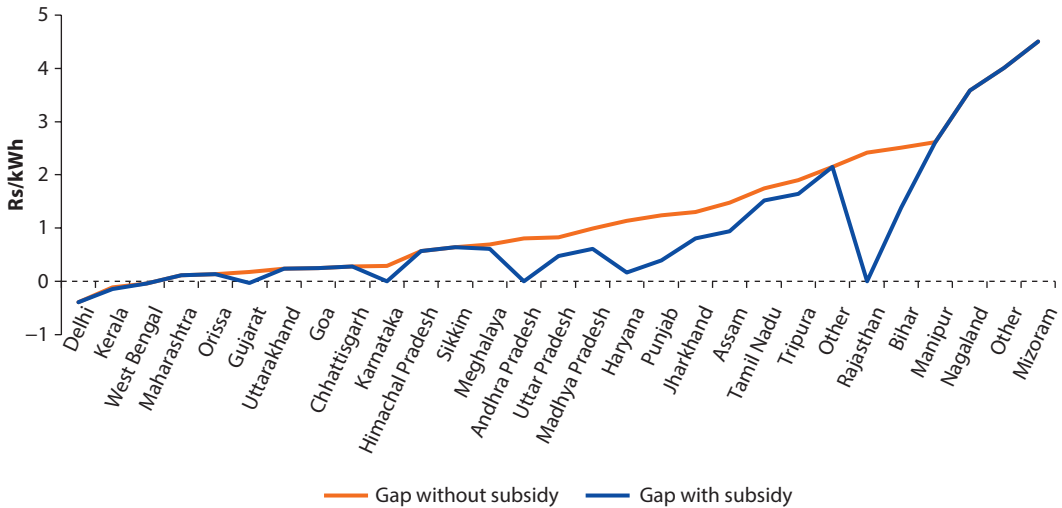
In 2011, only Delhi, Kerala, and West Bengal reported that average revenues with subsidy recouped the cost of power. Gujarat, Andhra Pradesh, and Rajasthan join this list when the gap with subsidy is considered (in these states, the subsidy booked is almost exactly equal to the amount of losses). The remaining states show a positive gap with or without subsidies. Mizoram reported the highest gap between costs and revenues, with revenues trailing costs by 69 percent, followed by states such as Nagaland and Manipur (figure 2.12). Even though none of these states with large gaps received an explicit subsidy, the gap is covered by the state budget. Rajasthan and Bihar also reported high gaps, covered in large part (Bihar) or entirely (Rajasthan) with booked subsidies.

Cost recovery performance has followed a fluctuating trajectory. In 2003, only three states—Chhattisgarh, Goa, and Uttarakhand—reported a negative gap without subsidies. Four more states joined this list when subsidies are taken into account. The following years revealed improvement until 2009, when 12 states reported a negative gap with subsidies. Nine states were making profits without subsidies in 2009. The situation deteriorated in 2011, and only three states reported profits without subsidy in that year.

Figure 2.11 Cost Recovery Performance, 2003–11



Source: India Power Sector Review Database.

Figure 2.12 Cost Recovery Performance with and without Subsidy

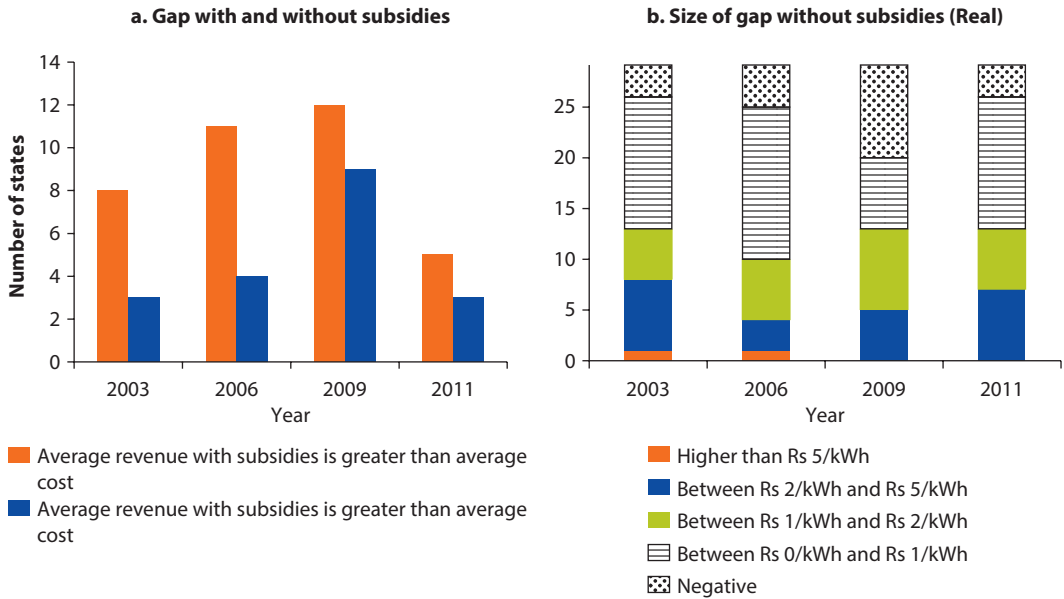
Source: India Power Sector Review Database.

The size of the gap also changed. In 2006, 19 states reported either a negative gap or a relatively small gap of less than Rs 1 per kilowatt hour. In 2009, more states were profitable, but 13 states reported gaps of more than Rs 2 per kilowatt hour, compared with 10 in 2009. In 2011, about seven states had gaps between Rs 2 and Rs 5 per kilowatt hour. The situation in 2011 appeared in real terms is similar to that in 2003, with relatively more promising results before distribution finances shifted downhill from 2009 onward (figure 2.13).

The gap between total costs and collected revenues has three components: underpricing due to low tariffs, distribution losses, and collection losses. The slower growth of revenue relative to costs is primarily stems from failure to increase tariffs commensurate with cost increases (figure 2.14). In 2003, states were, in aggregate, charging an average billed tariff well above cost recovery levels, and losses in that year were overwhelmingly the result of distribution losses.⁵ In contrast, in 2011, states were, in aggregate, charging an average billed tariff below cost recovery levels. Fifteen states had an average billed tariff below cost recovery levels in 2011. Even then, distribution losses contributed the largest part of total losses. Revenues lost at the collection point have remained relatively stable over the years.

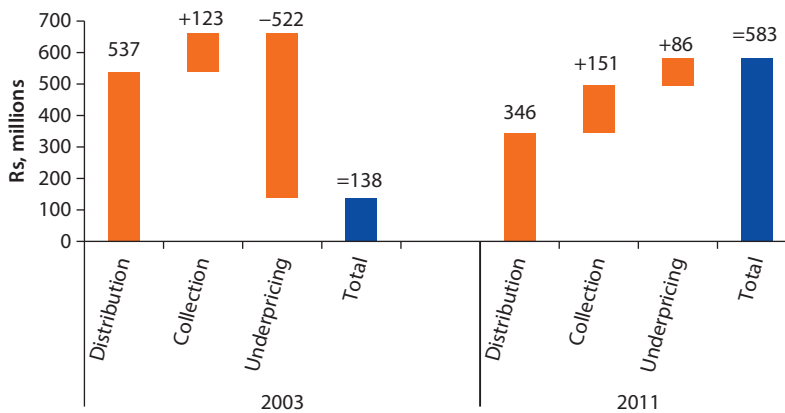
Tariffs: The average billed tariff is an amalgamation of tariffs charged to the primary consumer groups: industrial, domestic, and commercial. Domestic tariffs are lowest for all states in India. The variation is highest for Kerala, while Nagaland's billed tariffs show the least variation. Domestic tariffs remain uniformly low throughout all the states, industrial tariffs are highest for 18 states, and in 11 states commercial tariffs are the highest. Bihar had the highest effective

Figure 2.13 Evolution of the Cost-Revenue Gap



Source: India Power Sector Review Database.

Figure 2.14 Decomposition of Losses in 2003 and 2011

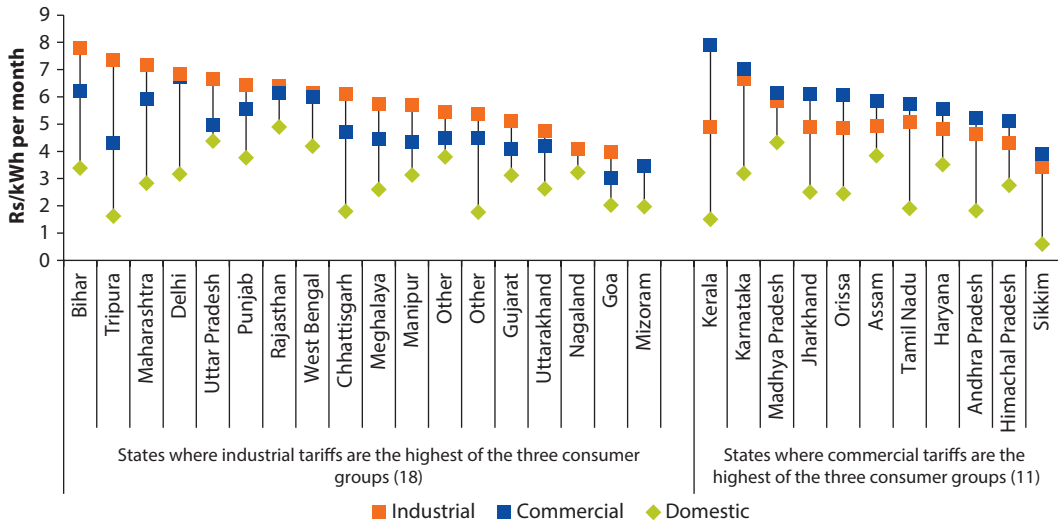


Source: World Bank.

Note: Distribution and underpricing losses are as defined above. Collection losses are the amount of revenue that goes uncollected, calculated as the difference between revenue billed and revenue collected.

industrial tariff at Rs 7.82 per kilowatt hour, while Kerala has the highest commercial tariffs (the highest in any category). Sikkim reports the lowest effective domestic tariff at Rs 0.6 per kilowatt hour. Goa has the lowest effective commercial tariff (figure 2.15).

Figure 2.15 Average Effective Tariff, by Consumer Group, 2012



Source: World Bank.

Table 2.2 Tariff Performance and Utility Losses, 2011

Group	Description	States
1	Tariffs are not set at cost recovery levels, but states achieve profits with subsidies.	Andhra Pradesh and Rajasthan
2	Tariffs are not set at cost recovery levels, and states record losses even with subsidies.	Assam, Bihar, Haryana, Punjab, Tamil Nadu, and Tripura
3	Tariffs are not set at cost recovery levels, and states record losses without subsidies.	Goa, Himachal Pradesh, Manipur, Mizoram, and Nagaland
4	Tariff are set at cost recovery levels, but states do not make profits even with subsidies.	Chhattisgarh, Jharkhand, Karnataka, Madhya Pradesh, Maharashtra, Meghalaya, Orissa, Sikkim, Uttar Pradesh, and Uttarakhand
5	Tariffs are set at cost recovery levels, and states make profits with subsidies.	Gujarat
6	Tariffs are set at cost recovery levels, and states make profits without subsidies.	Delhi, Kerala, and West Bengal

Source: World Bank.

Note: Subsidies are those subsidies booked by the distribution utilities.

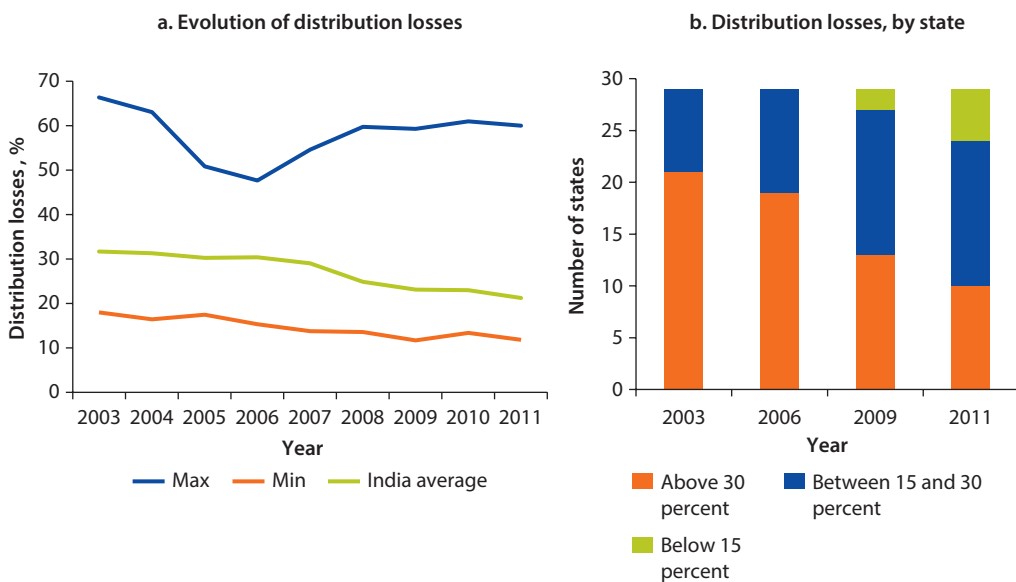
The urban domestic sector remains heavily subsidized, with only one state, Uttar Pradesh, able to recover average costs via tariffs in 2012. This situation has changed from 2003, when five states—Gujarat, Haryana, Karnataka, Madhya Pradesh, and Rajasthan—were covering average costs through domestic tariffs. For commercial consumers, Kerala had the highest positive effective tariff gap of Rs 3 per kilowatt hour, and Chhattisgarh is the best-performing state for industrial tariffs with a gap of Rs 2.8 per kilowatt hour. The state with the largest negative domestic, commercial, and industrial gap is Mizoram. Tripura and Nagaland

are other states that suffer from a large negative gap. Overall, only 17 and 18 states were able to recover their average costs from commercial and industrial tariffs, respectively. Over time, fewer states have been able to meet their average costs through domestic and industrial tariffs until major tariff changes were adopted in 2012.

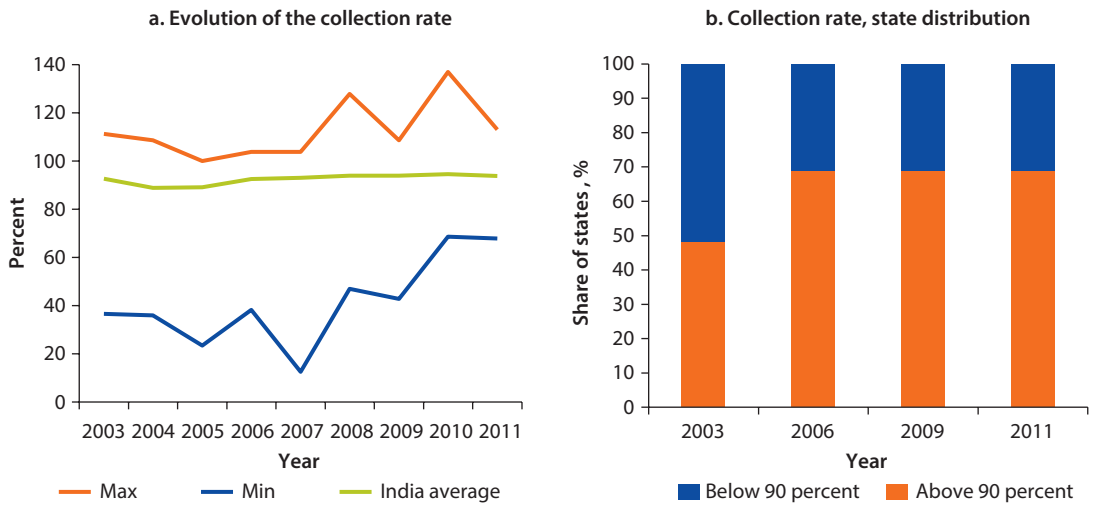
Distribution Losses: The difference between input energy and energy sold constitutes distribution losses, comprising both technical and nontechnical losses. International experience suggests that technical losses should be no more than about 10 percent. Distribution losses have fallen since 2003, when average losses were about 32 percent, and 18 states reported losses above this average. Three Indian states including Manipur have consistently reported the highest distribution losses. In 2003, Manipur’s distribution losses were 66 percent, which meant that it sold only 34 percent of the energy it input to the grid. In 2011, distribution losses averaged 21 percent across all states.

Until 2006, no state reported distribution losses of less than 15 percent. Himachal Pradesh was the first state to do so, achieving a loss rate of 13.8 percent in 2007. Since then, the number of states with distribution losses of less than 15 percent has grown (figure 2.16). In 2011, the lowest distribution losses were reported in Kerala, at about 12 percent, which is similar to international best practice. Andhra Pradesh, Goa, and Punjab have also recorded distribution losses of less than 15 percent of their input energy. These cases demonstrate that states within India are capable of registering impressive results that can be emulated by other states—even though eight states still lose more than 30 percent of their input energy.

Figure 2.16 Distribution Losses, 2003–11



Source: India Power Sector Review Database.

Figure 2.17 Collection Rate, 2003–11

Source: India Power Sector Review Database.

Collection Rate: The proportion of energy realized as revenue to energy billed was 94 percent in 2011. Collection efficiency has generally remained stable, rising only slightly from 89 percent in 2003 (figure 2.17). A majority of states now report collection efficiency higher than 90 percent. Ideally, however, the states should be collecting revenue from 100 percent of the energy billed. The consistently good performers are Delhi and West Bengal, followed by Punjab and Gujarat. However, metering is not universal for all customers in many states, and without accurate meter reading for all customers it is not possible to measure with precision the amount of energy to bill. Many states struggle to collect revenue at the last mile for a number of reasons, including incomplete metering, insufficient use of technology to bill and collect payments, and insufficient incentives for bill collection personnel.

Notes

1. The majority of Sikkim's energy supply comes from hydro sources, either within the state or through long-term contracts with the National Hydroelectric Power Corporation.
2. Unscheduled interchange is a part of a three-part tariff in the availability-based tariff at the interstate level, set up to ensure grid efficiency and grid discipline. UI charges are penalties for deviating from the drawl schedule at the conditions prevailing at the time of deviation. See http://greatlakes.edu.in/gurgaon/sites/default/files/Issues_in_Unscheduled_interchange_in_India.pdf.
3. Base load power supply in India includes coal (116 gigawatts), nuclear (5 gigawatts), and hydroelectric (39 gigawatts). Source: CEA 2012.

4. Black and Dirty: The Real Challenges Facing India's Coal Sector, Prayas Energy Group, Pune, India. <http://www.prayasenergy.org/peg/publications/item/191-black-and-dirty-the-real-challenges-facing-india%E2%80%99s-coal-sector.html>.
5. Distribution losses are the difference between "ideal sales" (defined as 90 percent of input energy, assuming that technical losses of 10 percent are unavoidable) and actual energy sold. A cost recovery tariff is a tariff greater than or equal to the average total cost divided by "ideal sales." The average billed tariff is revenue billed divided by energy sold. States have losses from underpricing if the average billed tariff is greater than the cost recovery tariff and gains from underpricing otherwise.

Reference

Central Electricity Authority. 2012. *All India Electricity Statistics, General Review, 2011*. New Delhi: Central Electricity Authority, Ministry of Power.

The Roles of Different Stakeholders in the Current Power Sector Scenario

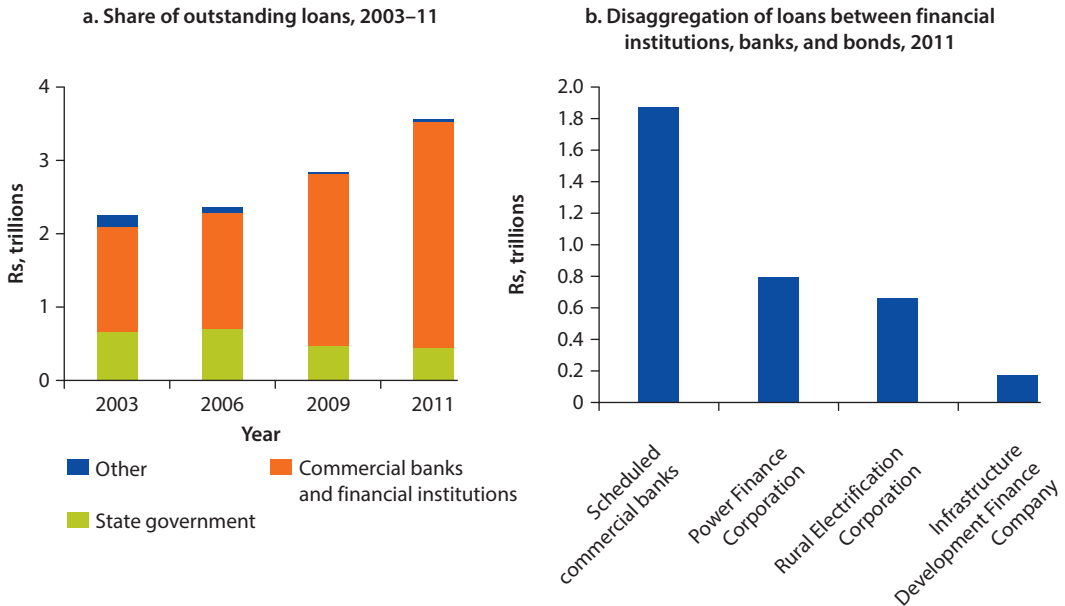
The current crisis in the power sector is more severe than the crisis of 2001 because many stakeholders are involved. The financial situation of the power sector stems from a complex interplay between utilities and key stakeholders. These key stakeholders, which include regulators, state governments, and banks, influence the direction (or misdirection) of the sector. This chapter first discusses how the stakes have been raised in the current crisis, and then reviews the roles of stakeholders in contributing to the crisis in the power sector to reveal the intertwined nature of causes and effects.

The Present Crisis and Its Ripple Effects

Power sector developments in the past two decades have brought new players into a traditionally government-dominated sector. These new players have also been implicated in the growing power crisis, particularly the effect on the financial sector and on private sector balance sheets in addition to the increased pressure on the state budgets. The poor condition of the power sector has created ripple effects, reflected in adverse market signals and the financial situation of many associated players.

Banks and Other Financial Institutions: The exposure of banks and other financial institutions has escalated. In 2011, commercial banks held about half of the Rs 3.5 trillion power sector debt. The remainder was lent by financial institutions such as the Power Finance Corporation (PFC), Rural Electrification Corporation (REC), and Infrastructure Development Finance Company at concessional rates to the power sector. The total contribution of commercial banks and other financial institutions stood at about 86 percent of total sector debt in 2011 (figure 3.1). Distribution companies accounted for the largest share of outstanding loans, followed by generation companies. During 2006–11, lending to distribution companies grew by 30 percent annually, followed by lending to transmission and generation companies at 17 and 15 percent, respectively.

Figure 3.1 Outstanding Loans, Distribution by Type of Loan and by Private Creditor



Source: India Power Sector Review Database.

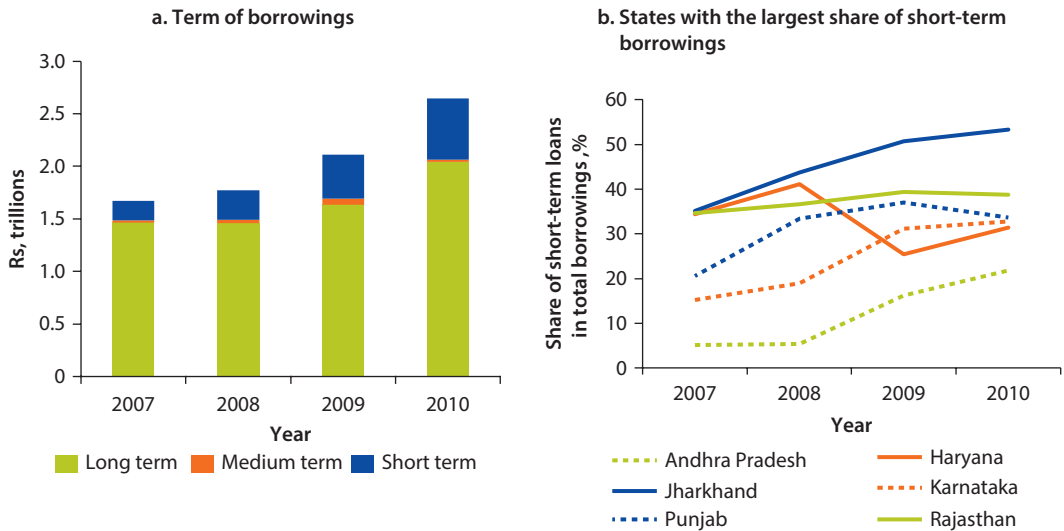
Lending to the sector has been fueled by heightened short-term borrowing by distribution companies to meet their operating expenses, new investment by state-owned generation and transmission companies, and the unprecedented surge of investment in new generation projects by private developers. The proportion of long-term loans has fallen over the years. They constituted about 87 percent of the total loans in 2007, but fell to 77 percent in 2011 (figure 3.2). During the same period, the rise in the share of short-term loans imposed a substantial interest burden on utilities. Six states—Andhra Pradesh, Haryana, Jharkhand, Karnataka, Punjab, and Rajasthan—have the largest shares of short-term borrowing in their total debt. The borrowing profile of Jharkhand is particularly noteworthy, with about 53 percent in short-term debt in 2011.

Private Developers: The private sector, particularly those participants building generation assets, is at risk. Private interests are largely dominated by Indian companies. A few multinational players, such as China Light and Power and AES Corporation, are active in India, but their generation capacity is limited. Before passage of the Electricity Act, 2003, the Indian power sector was rarely considered to be an investment destination for private capital. This sentiment has rapidly changed since 2000. Generation has attracted the most attention because it is the most straightforward investment proposition.

As established in the Electricity Act, 2003, generation became an unlicensed activity, removing significant bottlenecks to private sector development. Over the years, India has painstakingly built a robust private developer base, and the reforms have transformed the power sector into an attractive investment

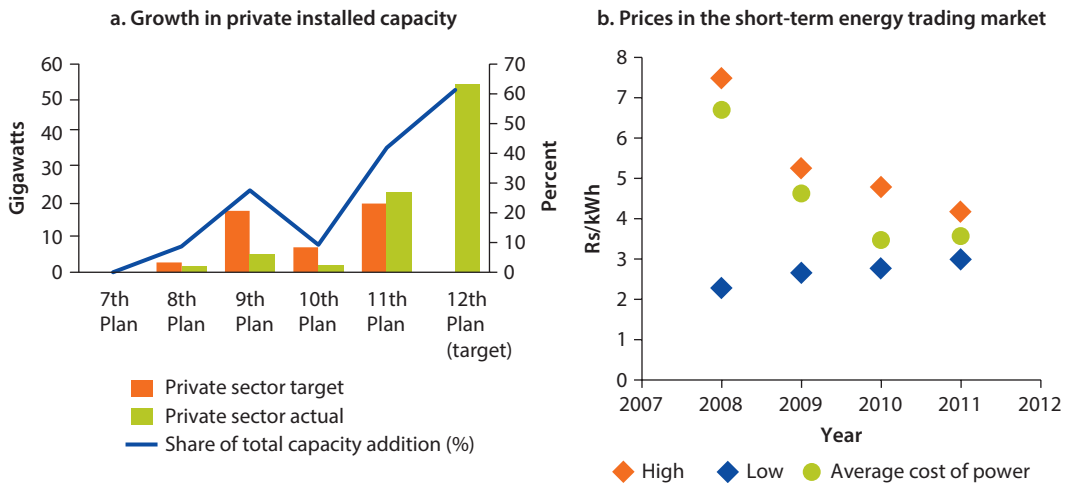
opportunity. Consequently, a large number of companies, not only from the power and infrastructure sectors but also from other core and noncore sectors, have come forward to submit investment bids. As a result, during the 11th Plan period the private sector exceeded the original target of 19 gigawatts of added capacity (out of a total target of an additional 77 gigawatts), rapidly increasing its market share. In the 12th Plan, the government intends to add 94 gigawatts, of which nearly half (\$50 billion) is envisaged to be private investment (figure 3.3). This investment will double the capacity installed by the private sector from

Figure 3.2 Utility Borrowing, by Term, 2007–10



Source: India Power Sector Review Database.

Figure 3.3 Opportunities for the Private Sector in Generation and the Short-Term Market



Source: Central Electricity Authority (CEA), Central Electricity Regulatory Commission (CERC).

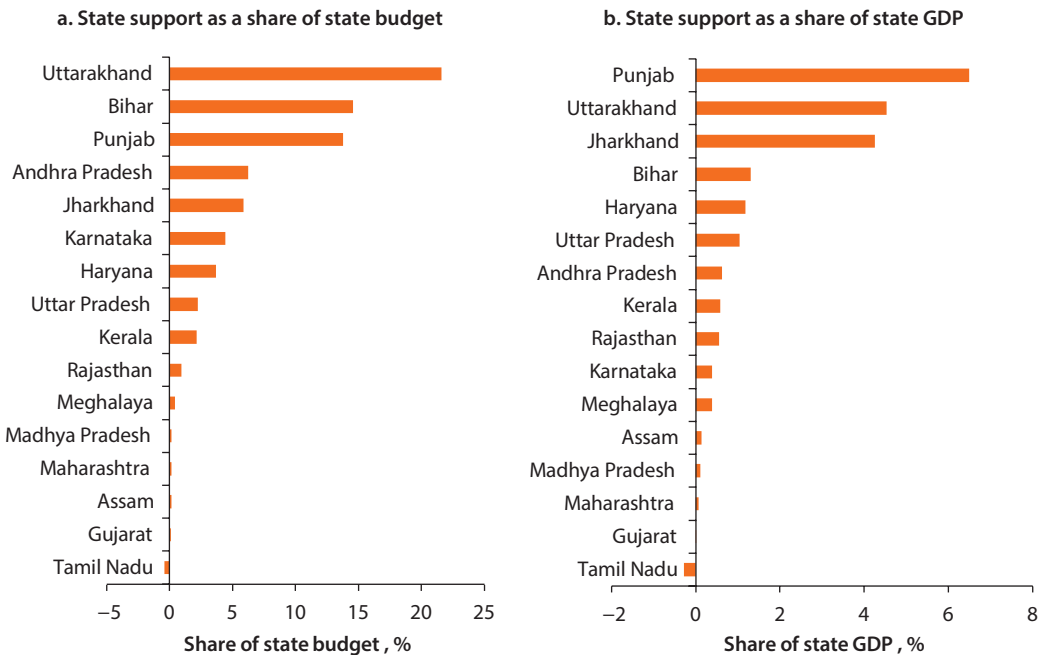
55 gigawatts to 116 gigawatts. This trend is likely to continue into the foreseeable future on account of the capacity stock under construction and development.

In addition to the generation business, the private sector has also been increasingly involved in the emerging trading market for short-term energy supplies (see figure 3.3). High prices in the early periods of trading on power exchanges have also attracted an infusion of new capital into the sector.

State Government: Total state support to the power sector includes not only subsidies but also state government loans and grants. In a majority of states, this support represents a relatively minimal proportion of state gross domestic product (GDP), less than 1 percent (figure 3.4). Nevertheless, state support places an imposing burden on the budgets of several states. For instance, in 2011 power sector support in Uttarakhand’s budget accounted for 22 percent of its budget, followed by Bihar and Punjab at 15 percent and 14 percent, respectively. All three states saw dramatic jumps in power sector support in 2011 compared with previous years. The allocation of these resources to the power sector represents an opportunity cost to the economy and could be measured as the numbers of hospitals and schools that could have been built instead. Rough calculations, assuming that a hospital costs Rs 28 million to build and a school, Rs 4 million, suggest that about 15,000 hospitals and 123,000 schools could have been built in 2011.

The recent power sector crisis has changed the size of state support compared with the precrisis situation in 2007. None of the 16 states considered in this analysis then had state support exceeding 2 percent of GDP. But in 2011,

Figure 3.4 State Support as a Share of State Budget and State GDP



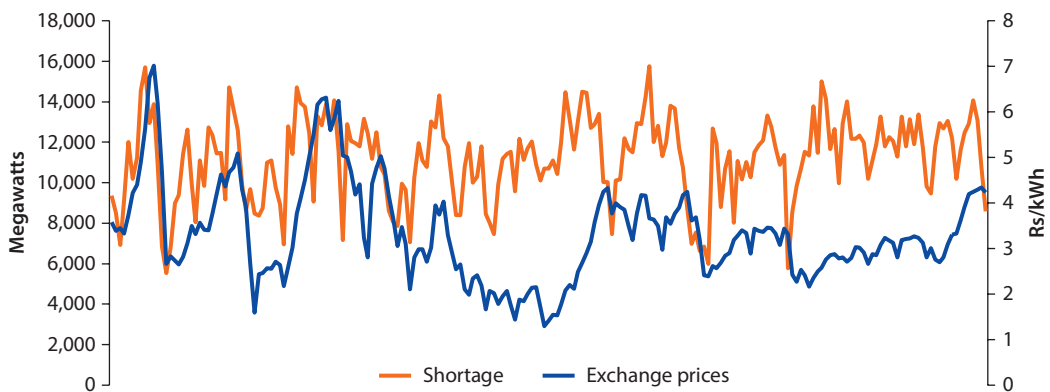
Source: India Power Sector Review Database.

Jharkhand, Punjab, and Uttarakhand devoted between 4 and 6 percent of GDP to the power sector. Similarly, only in Bihar and Jharkhand did state support exceed 2 percent of GDP in 2007, but nine states reached this level in 2011.

Creditors: As a result of this evolving crisis, creditors to the power sector face barriers to new lending. Distribution companies are severely cash constrained, many having run up outstanding debts for power purchase that have reached alarming levels. Uttar Pradesh is in its own category, with creditor days at 478 and outstanding debts of nearly Rs 232 billion. Among major states, only Chhattisgarh and Gujarat have paid off their debts on time. Utilities that are unable to pay their costs are then unable to make the investments necessary to serve customers. They are also not able to pay for power purchases from generating companies even when electricity is available on exchanges. This situation not only results in poor quality of supply but also leads to inadequate capacity utilization in generating stations. Independent power producers now account for an increasing share of generation space, growing from 14 percent to 29 percent between 2007 and 2012, but a number of private sector players are not receiving timely payment from distribution companies. Private players depend on debt from banks and other financial institutions: The typical private project has a debt-to-equity ratio of 70:30. This high proportion of debt results in increased pressure to repay creditors on a regular basis.

Consumers: Cash-strapped utilities are resorting to load shedding to avoid buying expensive power on the short-term market even when supplies are available. Power exchange prices are on a downward trajectory despite rising demand in the market. Even as distribution companies were load shedding about 10,000 megawatts daily, short-term prices were falling, at times dipping below long-term prices, which are typically about Rs 3 per kilowatt hour (figure 3.5). This trend is contrary to macroeconomic theory, in which excess demand should drive up prices in competitive power markets. The burgeoning financial losses faced by the distribution companies have led to a situation in which they are not able to procure power, even at these reduced prices. As a result, consumers have to cope with poor and inadequate power supply.

Figure 3.5 Peak Deficit and Short-Term Prices, Daily, June–December 2012



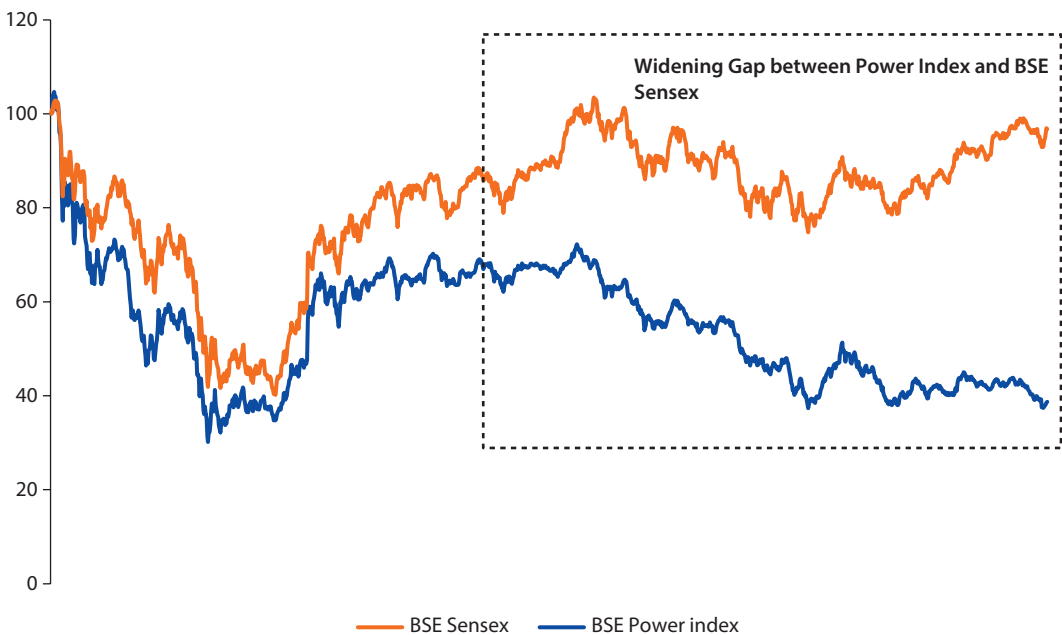
Source: CEA, CERC.

Load shedding has implications for the use of captive power. Expensive standby options, such as diesel-based generators, become an important source of electricity. However, diesel is also subsidized at about Rs 12 per liter, and the costs to the treasury for the use of diesel for backup power are therefore enormous (estimated to be Rs 100–150 billion per year).

Consumers will also suffer from a potential rise in long-term prices. Governments have allowed developers under the Case 2 bidding process to sell a certain portion of generated power in the wholesale power market.¹ Given the current and projected energy demand-supply gap, most estimates had pointed toward attractive opportunities in the short-term market. Hence, short-term sales on power exchanges were expected to subsidize long-term sales, allowing developers to submit bids for long-term sales at competitive rates. Consequently, developers bid low, keeping long-term power purchase costs at reasonable levels. However, given current input costs, the long-term pricing at which most bids are being undertaken would actually result in single-digit internal rates of return for the developer if its entire output were sold on a long-term basis. If this situation continues, the short-term power market would no longer provide an indirect subsidy to the long-term market, resulting in higher long-term pricing.

Market Signals: The market is already responding to the conundrum that the power sector faces today. For instance, the Bombay Stock Exchange (BSE) Power Index has consistently underperformed the Bombay Stock Exchange Sensitive Index (BSE SENSEX) during the last few years, and this performance gap has widened during the current fiscal year (figure 3.6).

Figure 3.6 Gap between BSE Power Index and BSE SENSEX, January 2008–March 2013



Source: Bombay Stock Exchange.

Note: BSE SENSEX = S&P Bombay Stock Exchange Sensitive Index.

Key Stakeholders That Contributed to the Present Crisis

State Regulatory Commissions

The State Electricity Regulatory Commissions are autonomous bodies that have wide-ranging powers and are insulated from political interference under the provisions of the Electricity Act, 2003. The role of a regulator includes setting tariffs that reflect costs, ensuring that service standards are met, and promoting competition in the sector. A culture of independent regulation that seeks to protect long-term consumer and supplier interests has, however, been replaced by an emphasis on short-term expediency, perpetuating a vicious cycle that has resulted in inadequate revenues and deteriorating finances. This outcome has directly contributed to a derelict power network, poor employee motivation, and an inability to conduct long-term financial and operational planning. Disallowance of expenses, underestimates of agriculture supplies and the corresponding subsidies, and the return on capital are only some of the key points resulting in disconnects between the utilities and the regulators.

Expense Disallowance: The discrepancy between the expenses reported in utilities' average revenue realized and the expenses allowed by the regulator is evident across the power sector. State regulators set targets and provide incentives to the utilities to increase operational efficiency. It is critical for the financial performance of the utility that these targets be achievable and based on historical performance. Although the following discussion does not evaluate the legitimacy of specific claims and denials, large discrepancies between the claims by the utilities and approvals by the regulator are evident.

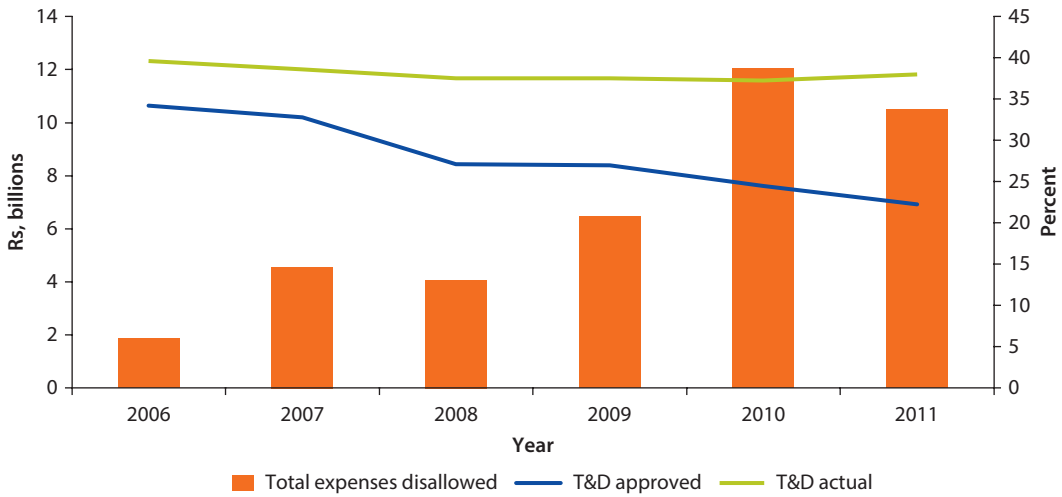
Power purchase costs generally account for 70 to 80 percent of a distribution company's total costs, and disallowance of a portion of power purchase costs can have adverse impacts on cash flows. In principle, distribution companies and their regulators agree on the amount of power to be purchased during the tariff period, usually one year. The sources of that power are also specified. In certain states, the regulator may allow distribution companies to purchase power on a wholesale exchange to compensate for shortages, but may disallow power purchases over a certain price. However, in reality regulators and utilities often do not agree on the amount of power that is required during a tariff period. In recent years, many regulators have disallowed the full amount of power purchased during the review period, and distribution companies have therefore not been able to recover the full costs of power purchases.

For their part, distribution companies may not have not been able to reduce losses according to the schedule agreed upon with the regulator. However, the estimation process for transmission and distribution losses is neither transparent nor accurate, and disagreement about the value of the losses is frequent. For example, between fiscal years 2006 and 2011 distribution companies in Orissa failed to meet their loss-reduction targets. Year after year, the regulator was forced to set lower targets after the utility was unable

to meet the previous year’s target (figure 3.7). In 2011, approximately 22 percent, or Rs 10.5 billion, of total expenses were disallowed on account of this failure to meet loss-reduction targets, severely affecting the long-term financial viability of the utility.

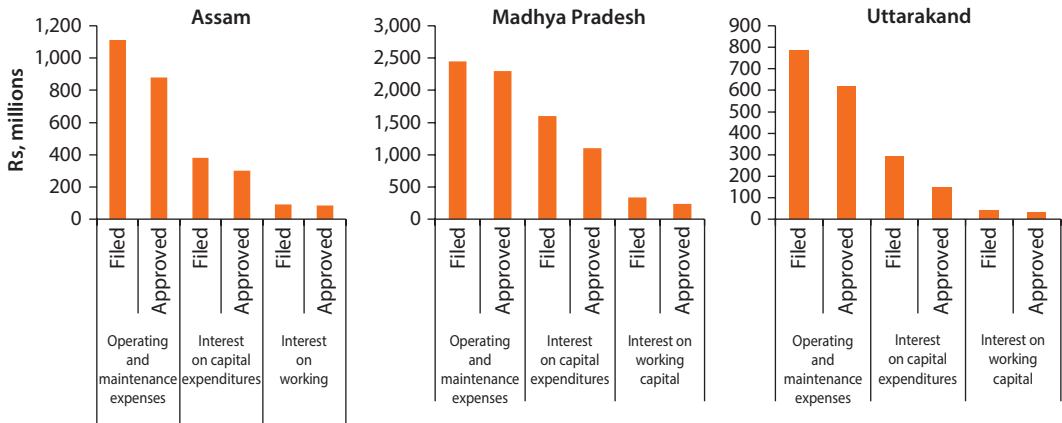
Similar disallowances occur in the transmission and generation segments. Figure 3.8 shows the variation between the costs filed and costs approved for three transmission companies in Assam, Uttarakhand, and Madhya Pradesh in 2011.

Figure 3.7 Impact on Disallowances of the Variation between Approved and Actual Transmission and Distribution Losses in Orissa, 2006–11



Source: Orissa Electricity Regulatory Commission Annual Reports, 2010–11, 2011–12.
 Note: T&D = transmission and distribution losses.

Figure 3.8 Transmission Company Costs Filed versus Approved, 2011

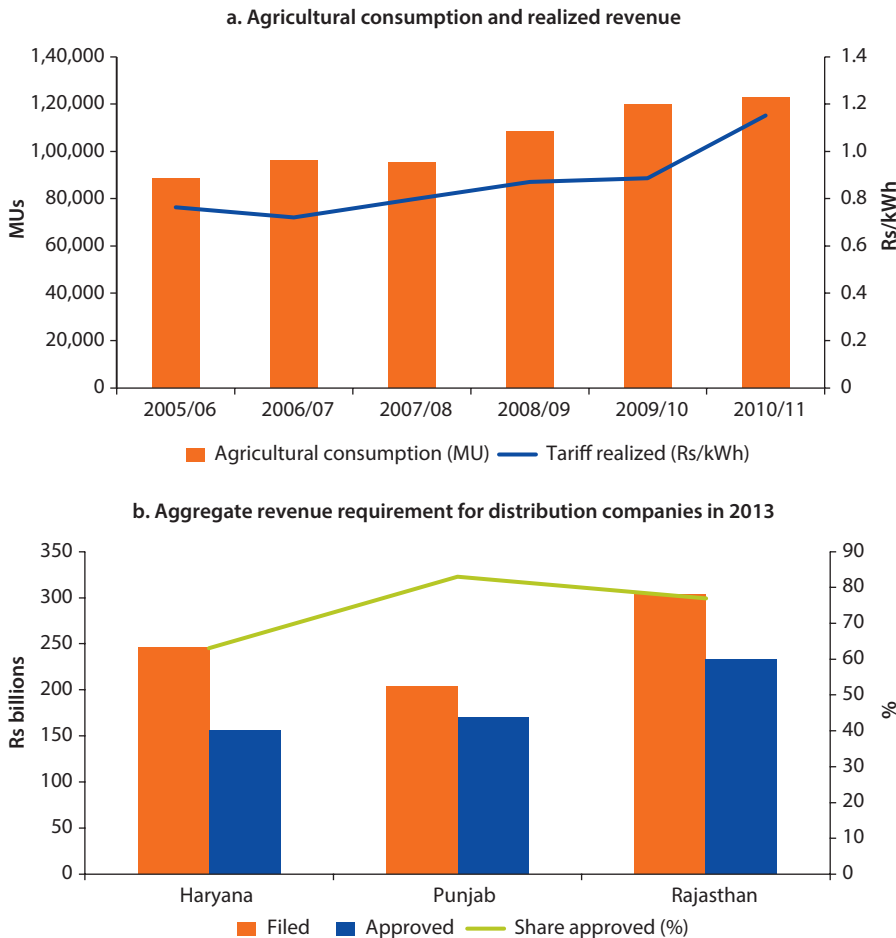


Source: Utility accounts.

Expense disallowance through the regulatory process can have spill over effects on financial performance. These utilities are forced to borrow to cover operational costs the next year. In the subsequent tariff period, these short-term borrowing costs may then be disallowed, further increasing losses. The resulting financial strain in turn reduces investment in efficiency improvement and proper planning, which further diminishes performance.

Estimation of Agriculture Consumption and Subsidy: Agriculture consumption is largely unmetered. As a result, agricultural consumption is always an estimated figure. This leads to “padding” agricultural consumption to make up for excessive losses in other segments. Another consequence of the lack of metering is that actual motor sizes and load may be quite different from sanctioned load. This situation leads to data inconsistencies and discrepancies

Figure 3.9 Agricultural Tariffs and Average Revenue Realized



Source: CEA, SERC tariff orders.

Note: kWh = kilowatt hour; MU = million units.

in the calculation of the subsidy by the regulator and by distribution companies. Electricity tariffs for farmers amount to less than 10 percent of the cost of supply. Typically, farmers pay a flat rate per unit of horsepower per pump; the actual level of power use is not metered or recorded. The state provides a subsidy to the utility to bridge the gap between the agricultural tariff and cost of supply. Some states, such as Tamil Nadu, supply power for free. However, the distribution companies and state electricity regulatory commissions (SERCs) can differ widely in their estimates of the aggregate revenue required. These discrepancies may be due to problems such as the utility's inability to provide reliable data or lack of an agreed methodology to determine consumption. In the case of Haryana, only 63 percent of the requested sum was approved, amounting to a shortfall of more than Rs 90.156 billion in 2013 (figure 3.9).

Disallowance of Return on Equity: The Electricity Act, 2003, empowered the Central Electricity Regulatory Commission to specify the terms and conditions for determining tariffs for the generating companies that are either owned by the central government or supply power in more than one state. The CERC can also determine the tariff rates levied by transmission licensees for interstate transmission of electricity. CERC has set the return on equity (ROE) on generation and transmission projects at 15.5 percent. The SERCs are guided by these regulations while framing their own tariff principles for the state sector. The SERCs in some states, such as Bihar, Haryana, and Uttar Pradesh, either do not allow the specified annual ROE set by CERC or allow the generation and transmission utilities to recover less than that ROE.

Buildup of Regulatory Assets: In some cases, SERCs do not increase tariff rates to avoid tariff shock to the consumer. The distribution utility's resulting revenue deficit is recognized by the regulatory commission with a proposal for recovery through a future tariff increase. This uncovered amount is termed a "regulatory asset." Over the past few years, these regulatory assets have built up substantially in many states, such as Delhi, Haryana, Punjab, Rajasthan, Tamil Nadu, Uttar Pradesh, and West Bengal, resulting in a huge debt burden to fund the deficits (see table 3.1 for data from selected states). According to the provisions of the Appellate Tribunal's ruling, these regulatory assets ought to be recovered over a three-year period. If tariff increases reflecting recovery of

Table 3.1 Regulatory Assets of Major States, March 31, 2012

<i>State</i>	<i>Regulatory assets (Rs billion)</i>
Tamil Nadu	13.968
Rajasthan	11.235
Punjab	13.257
Haryana	30.710

Source: http://www.moneycontrol.com/news_html_files/news_attachment/2012/Power-Distribution-Sector_ICRA_270312.pdf.

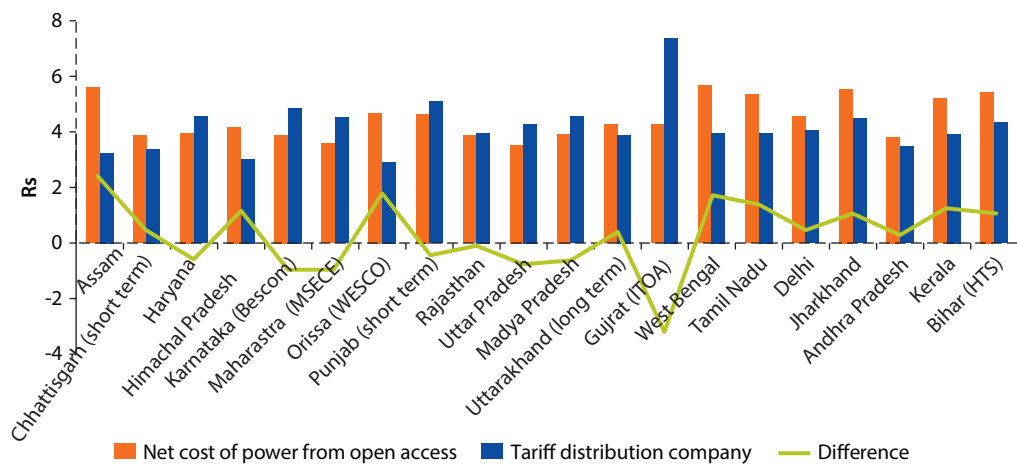
these assets were imposed, consumers would suffer a major price shock. In reality, recovery is being scheduled over a longer time horizon.

Uptake of Open Access: The success of open access relies on the transmission and distribution companies to transmit the energy, and on regulatory commissions to facilitate the process through adequate regulations and mechanisms to enable nondiscriminatory open access. Regulations on open access have been formulated by the SERCs in several states. In practice, open access faces significant challenges, often embodied in the regulations that are intended to promote it. In most cases, the cost of power procurement through open access is higher than under the utility tariffs (figure 3.10). The wide variation in charges between states is a result of the different levels of component charges for open access. In particular, cross-subsidy surcharges have been used to erect tariff barriers to open access.

Several states have still not established open access regulations for certain categories of consumers (usually those with consumption above 1 megawatt). As of fiscal 2011, 22 states had issued notification of open access regulations, 20 had determined surcharges, 17 had determined wheeling charges, and 22 had determined transmission charges.

In recent years, open access customers have begun making purchases on day-ahead markets on the power exchanges. In the short term, hourly prices are quite predictable. A large number of industrial customers have therefore made forays into the day-ahead markets, using open access to supplement their supplies from utilities and thereby reducing costs. This strategy is particularly common in states

Figure 3.10 Comparison of Power Costs through Intrastate Open Access and through Distribution Utilities, 2011



Source: Forum of Regulators.

Note: Tariff for an embedded consumer of 5 megawatts at 11 kilovolts. Open access charges for a consumer of 5 megawatts at 11 kilovolts seeking open access for a month. MSEDCL = Maharashtra State Electricity Distribution Company Limited; LTOA = long-term open access; HTS = high temperature superconducting.

such as Chhattisgarh, Punjab, and Tamil Nadu, where cross-subsidy surcharges under Section 42 (2) of the Electricity Act are low, or where the penalty for over-drawing is significantly higher because of inadequate generation capacity.

However, the attitude of state regulators toward charges related to open access varies significantly with changes in supply conditions in the home state. In Punjab, for example, the open access surcharge under Section 42 (2) was increased from zero to Rs 74 per kilowatt hour in 2012 when the power supply position of the local utility improved. This change has affected the viability of open access trades in Punjab, although in off-peak hours procuring open access power remains a viable proposition for industrial consumers.

The SERCs are also often burdened with the impact of their decisions on consumer tariffs and can neglect their legal responsibilities to other sectors. The focus on retail tariffs has also diverted attention from quality-of-service issues. Inadequate staffing levels, competence gaps, and poor training on fundamental economic and technical regulation issues are endemic. As a consequence, SERCs remain weak and ineffective organizations, with few exceptions.

Going forward, the SERCs will have to play a more proactive role in implementing changes in provisions relating to open access, multiyear tariffs, and standards of performance, as envisaged in the Electricity Act. However, this strengthened role needs to be backed by strong political will that allows regulators independence in decision making. One approach could be to encourage public participation in proceedings before the SERCs to enhance transparency and reduce the scope for political influence. In addition, any changes should be effectively communicated to all stakeholders and their feedback invited to create more awareness regarding possible benefits.

State Government

Electricity is an essential service used by all segments of society. But because electricity is a scarce resource, it has often been used as an instrument of political patronage. By ensuring the supply of electricity to favored voting groups, politicians can win essential support. Although in theory electric utilities operate at arm's length from government, in practice this has rarely been the case. During elections, few states have displayed qualms about manipulating the electricity supply as an election tool, usually by buying power from short-term markets at Rs 4–7 per kilowatt hour to ensure uninterrupted electric power supplies ahead of the polls. This strategy was evident in the period leading up to the national general election in January 2009, and before the state elections in Tamil Nadu in March 2011 (IDFC 2012). This surge in the amount of power procured and in the cost of procurement usually leads to a shock in utility finances because the regulator may not allow the utility to pass the expense through to customers.

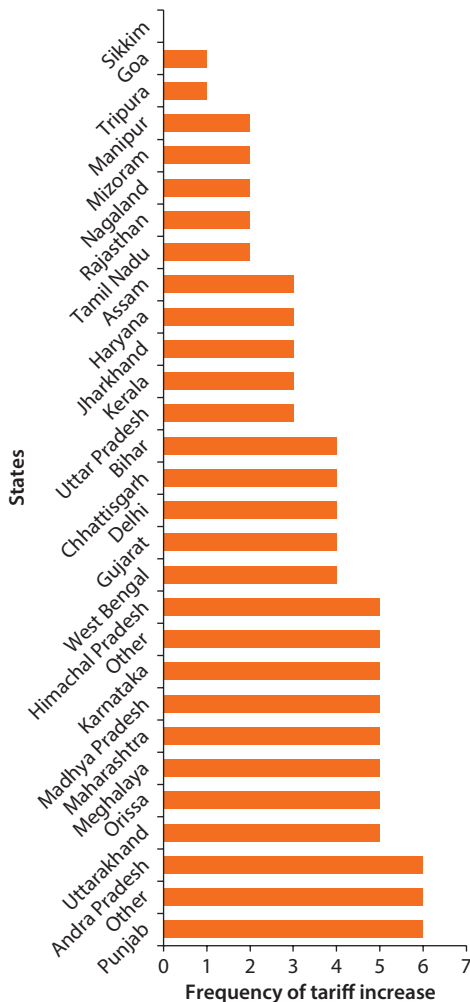
In addition, state governments are responsible for timely payment of subsidies. In many states, however, subsidies are not paid on time or in full despite provisions of the Electricity Act, 2003, that require subsidies for any consumer class to be paid in advance. Delays in the payment of subsidies can force the utility to borrow.

The discrepancy between the subsidies booked and those received from the government puts additional burdens on the state utilities. This gap between subsidies booked and subsidies received has been growing: in 2011, it was Rs 119 billion.

Because of the perception that tariff increases will have negative political consequences for the incumbent state government, many states have not increased tariffs for almost 10 years. Very few states have regularly revised tariffs to reflect cost increases (figure 3.11). Pressure on distribution companies' finances and the decision of the banks to restrict lending to loss-making utilities has recently forced some changes. In 2010–11, 17 states hiked tariffs, and in 2012, nine states (including some major loss-making states) increased tariffs, in some cases significantly.

The political decision to provide free electricity to agricultural and rural consumers in many states limits accountability for the operational performance of

Figure 3.11 Number of Tariff Revisions, by State, 2007–13



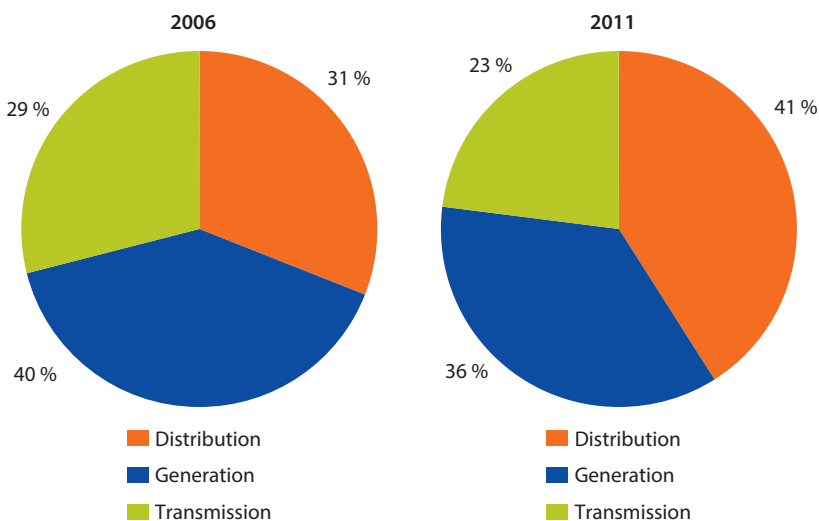
distribution companies. The precise extent of aggregate technical and commercial losses is not known in these states, since agricultural consumption is not metered. This fact is used to camouflage overall inefficiencies. In the future, it will be important for state governments to recognize that the utilities must be run on a commercial basis and be accountable for service delivery to consumers.

The Role of Key Stakeholders: Banks and Other Financial Institutions

Banks also bear some of the responsibility for the current crisis. Banks conduct rigorous due diligence before lending to a borrower, but the same due diligence was not carried out for power sector loans to state utilities. In recent years, banks have lent to distribution companies to provide liquidity, seemingly overlooking prudent lending norms. Broadly speaking, banks have based such lending on the quasi-guarantee of state governments. Although many utilities have been insolvent, they have continued to receive loans from banks. Distribution companies account for the largest share of outstanding loans, followed by generation companies. Over the period 2006–11, lending to unbundled distribution companies grew by 35 percent annually and accounted for 41 percent of total lending (figure 3.12).

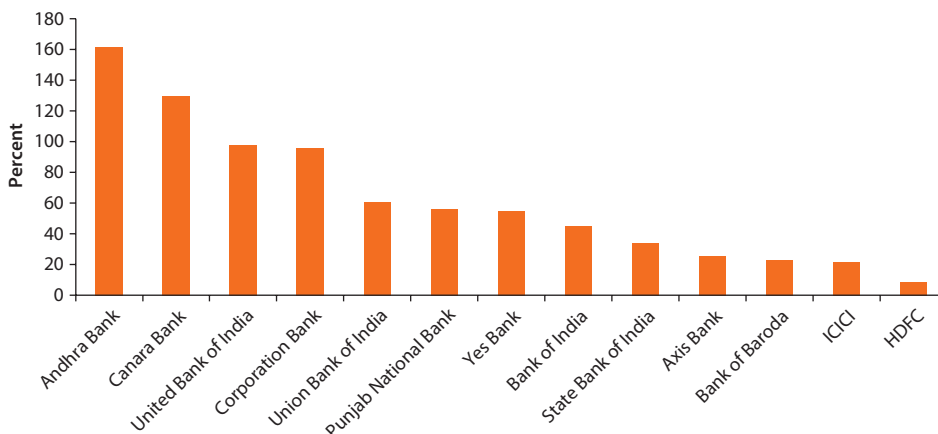
Unrestricted lending has also damaged banks' capital adequacy and net worth. An analysis of 13 major state-owned banks shows that more than half have funded loans to the power sector equal to or greater than 50 percent of their own net worth (figure 3.13). Unrestricted lending by banks has limited the accountability of distribution companies to improve performance and reduced the pressure on state governments to increase tariffs. Only when banks reduced lending to the sector in 2012 did states react and push through tariff reforms to ensure that the lights stayed on.

Figure 3.12 Lending by Financial Institutions to Different Segments of the Power Sector



Source: India Power Sector Review Database.

Figure 3.13 Funded Loans to the Power Sector as a Proportion of the Net Worth of Major Banks, 2010



Source: AF-Mercados EMI analysis 2012.

Table 3.2 Banks with Maximum Exposure to the Power Sector and the States They Have Lent to, 2010

Banks	Power exposure/total exposure to power sector (%)	Major states lent to
Canara Bank	20.3	Rajasthan, Karnataka, Haryana
Corporation Bank	12.8	Karnataka, Rajasthan
Andhra Bank	12.2	Rajasthan, Haryana, Andhra Pradesh
United Bank of India	9.4	Karnataka, West Bengal
Punjab National Bank	5.8	Rajasthan, Karnataka
Bank of Baroda	4.6	Rajasthan, Andhra Pradesh, Karnataka
Union Bank of India	4.5	Rajasthan, Karnataka

Source: Basel-II disclosures by banks; Power Finance Corporation; utility annual accounts.

The State Bank of India is the biggest lender to the sector on an absolute basis, and these loans correspond to about 30 percent of its net worth. The fund-based exposures of Canara Bank and Andhra Bank are more than 100 percent their net worth. Although looking at the exposure of banks to the sector is important, it is even more relevant to look at the states to which these banks have lent to estimate their chances of default. For example, the exposure of the United Bank of India is close to 10 percent, but it has mostly lent to relatively better performing states like West Bengal and Karnataka. However, although Andhra Bank’s exposure is just 2 percentage points higher, the states it has lent to are some of the poorest financial performers over the last few years (table 3.2).

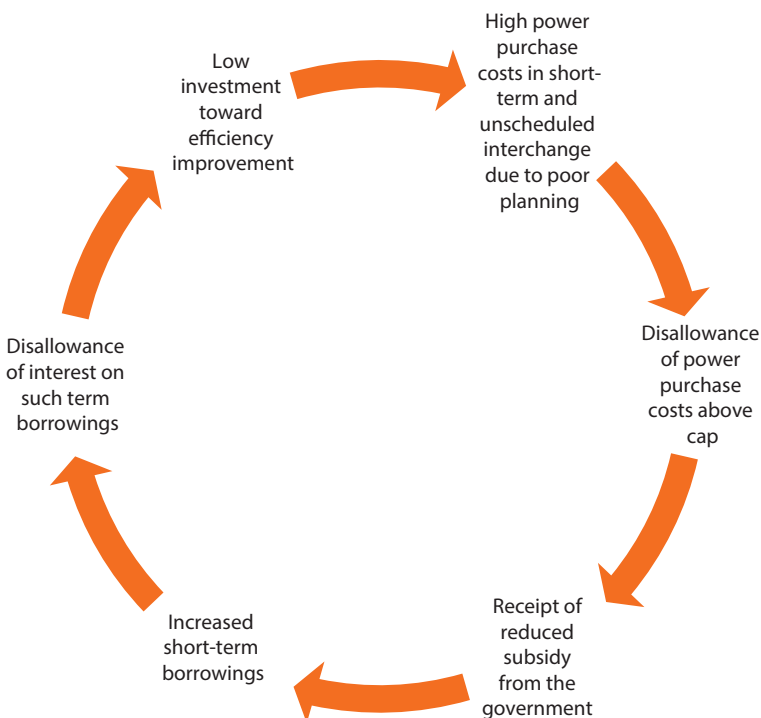
Profligate lending by banks and other financial institutions without adequate due diligence has brought the banking sector to a precipice and has served the power sector poorly because it has allowed the utilities to cover gross inefficiency.

These institutions need to tighten lending practices and conduct rigorous due diligence on both current and projected operations on efficiency and finances, management capability, state governments' track records for paying subsidies and promoting governance, the regulatory environment in the state, and other factors. If projects or utilities do not meet or exceed the requirements, then lending should be stopped. The banks and other financial institutions should also demand and take rights in utilities that breach financial covenants. This is a standard practice in all industries, nationally and internationally, and the power sector, which is required to be operated along commercial lines, should be no exception.

The Bailout Package of 2012

The inability of the various stakeholders to fulfill their responsibilities has led to a vicious cycle. Underrecovery of power purchase costs, incomplete or late subsidy payments by governments, pressure to keep tariffs low, and pressure to purchase power during elections to keep voters happy have forced utilities to borrow to cover operating costs. Utilities are then not allowed to recover the cost of this short-term borrowing in the following year, which further increases losses and sector debt. Financial strain, in turn, reduces investment in efficiency improvement and proper planning, which further diminishes performance (figure 3.14).

Figure 3.14 The Vicious Circle of Costs and Inefficiency



This cycle was broken in the second half of 2011 when the Finance Ministry advised public sector banks not to increase their exposure to power utilities, including distribution companies. Most banks had already reached the new sectoral caps for the power sector, mainly on loans for large generation projects. Most banks therefore refused to provide new loans to the power sector.

Given the huge cash flow problems, caps on bank loans, and regulators' failure to increase tariffs, the Appellate Tribunal for Electricity had to issue a judgment requiring SERCs to reset tariffs annually. In 2011, the Ministry of Power sent a letter to Appellate Tribunal for Electricity (ATE) requesting that ATE take action to ensure that SERCs and distribution companies alike revise tariffs periodically to ensure financial and operational viability. ATE issued a judgment on November 11, 2011, that gave the SERCs the responsibility for determining tariffs if the distribution utilities fail to meet the filing deadline (appendix D). This ruling led to a flurry of tariff increases. However, the longer-term impact of this judgment by ATE on the financial position of the utilities hinges on its implementation by SERCs in an independent manner without any influence from state governments or the utilities. In addition, poor data availability, significant delays in the finalization of accounts, and operational inefficiencies in energy audit systems in some cases could delay initiation of tariff proceedings by SERCs.

In September 2012, the Cabinet Committee on Economic Affairs approved a financial rescue scheme to revive the sector, which will be available to all loss-making distribution companies that wish to participate. This bailout amounts to about Rs 1.9 trillion and was a response to the problem of banks' and other financial institutions' large holdings of nonperforming assets (appendix C). The bailout requires state governments to take over 50 percent of outstanding short-term liabilities up to March 31, 2012. This debt will first be converted into bonds to be issued by distribution companies to participating lenders, backed by state government guarantees. The remaining 50 percent of short-term loans will be rescheduled with a moratorium on principal and the best possible terms for this restructuring to ensure the program's viability. The central government will provide a transitional finance mechanism to support the restructuring effort, subject to state governments' and distribution companies' fulfillment of the program's mandatory conditions. Two committees, one at the state level and one at the central level, will monitor the progress of the turnaround plan. The performance of the distribution companies will be verified annually through a third party appointed by the CEA.

This bailout package comes slightly more than a decade after the bailout plan recommended by M. S. Ahluwalia in 2001. As discussed earlier in this chapter, not only has the number of stakeholders increased, but the sheer magnitude of the funds required has more than quadrupled (table 3.3).

There are lessons to be learned from the 2001 bailout. Various bailout instruments were identified, such as a gradual reduction in the supply of power from the central public sector utilities and in coal supplies, to ensure that state electricity boards undertake reforms. However, implementation of these measures was not monitored, and these instruments were therefore never used. The current

Table 3.3 Comparison of the 2001 and 2012 Bailout Packages

	2001/02	2012
Defaulter	State power utilities	State power utilities
Owed money to	Central public sector utilities (National Thermal Power Corporation, Power Grid Corporation of India Limited, and others)	Banks and other financial institutions in the form of nonperforming assets
Amount due	Rs 0.41 trillion	Rs 1.9 trillion
Key element of the bailout package	50 percent of the interest on delayed payments was waived and the remaining amount (full principal plus remaining interest) converted into bonds by the state government	50 percent of the outstanding short-term liabilities up to March 31, 2012, to be taken over by state governments. This amount will be first converted into bonds to be issued by distribution companies to participating lenders, backed by state government guarantees of the balance. The other 50 percent of short-term loans will be rescheduled, with a moratorium on principal and favorable terms. The estimated losses for the current year will be funded by banks (70 percent) and state governments through a subsidy (30 percent).
Additional financing based on incentives	None	A transitional finance mechanism by the central government to support the restructuring program is available, subject to fulfillment of mandatory conditions of the scheme.
Monitoring arrangements	None	State governments and distribution companies must carry out certain mandatory and recommended conditions. For monitoring the progress of the turnaround plan, two committees at state and central levels, respectively, will be formed. Annual verification of the performance of the distribution companies will be done through a third party appointed by the Central Electricity Authority.

bailout package has established incentives with quantifiable targets in the transitional financing mechanism and the performance monitoring framework. Although these are positive steps, they do not ensure compliance. The package does not include a penalty to ensure that a “business as usual” mindset does not creep back into utility operations. Nor does it specify the implications for partial achievement beyond denial of the incentives.

The risk is that the monitoring mechanism will lose steam during the implementation process. The risks devolve completely on the state governments, which are the final residual risk bearers in the entire process because of the loan takeovers and the extension of guarantees. A possibility is that the disbursement of funds by banks, other financial institutions, and the central government may be linked to a few key performance parameters. A transparent, objective performance framework to measure utility performance is required. In the absence of performance-linked disbursements, the ability of stakeholders to enforce compliance with performance measures is limited. Success of the program depends greatly on the ability of states to follow through on the required reforms, especially annual tariff revisions, pass-throughs of fuel and power purchase cost adjustments on a quarterly basis, improvements in collection efficiency, and reductions in transmission and distribution losses. For their part, governments

must make timely disbursements of subsidy payments where such subsidies are required (table 3.4).

Eight states, Bihar, Haryana, Himachal Pradesh, Karnataka, Kerala, Rajasthan, Tamil Nadu, and Uttar Pradesh, account for 70 percent of the sector's short-term liabilities and have expressed interest in participating in the debt restructuring for utilities. Based on the projections for 2017, many of these states are also under the greatest financial risk because of their inadequate operating performance (table 3.5).

Table 3.4 Key Stakeholder Risks and Rewards of the 2012 Bailout Package

<i>Stakeholders</i>	<i>Rewards</i>	<i>Risks</i>
Banks	Rescued banks from recording huge nonperforming assets that might have breached their capital adequacy requirements. Banks will also see their exposure to the sector reduced by half, which would greatly increase their liquidity and net worth positions.	Lenders will have to wait longer to be paid back, and will possibly also have to offer terms for the restructured loans that are commercially unattractive.
State government	The states bear the risk for noncompliance of the utilities with performance conditions, which may encourage states to move toward commercialization of the state power utilities, thereby leading to proper functioning of the power sector in the state.	Additional stress on state finances. The additional liabilities from the power sector will reduce headroom and may make it difficult for states to comply with their future fiscal responsibility and budget management targets, forcing them to curtail capital expenditure in other areas.
Power sector utilities	Provides a breather for the electricity distribution firms owned by state governments that are finding it difficult to raise working capital. It will also benefit generators and traders because they can expect timely payments from distribution companies. Encourages the state power utilities to improve efficiency of operations performance.	The state utilities are taking new loans to cover the transition over the three-year program period, and in three to five years' time the existing restructured loans will also be due for repayment. It is imperative that they narrow the gap between average revenue and average cost in the next three to five years or the sector may find itself in a similar predicament.

Table 3.5 Status and Projections of Candidate States for Financial Restructuring

<i>State</i>	<i>Profit after tax, 2011 (with subsidy) (Rs million)</i>	<i>Total loans, 2011 (Rs million)</i>	<i>Ratio of debt to revenue, 2011 (%)</i>	<i>Projected gap with subsidy, 2017 (Rs/kWh)</i>
Bihar	-13,320	151,480	419	1.42
Haryana	-3,290	263,710	134	1.83
Himachal Pradesh	-5,110	41,780	118	-2.17
Karnataka	5,350	184,400	80	0.27
Kerala	2,410	13,840	20	0.55
Rajasthan	-40	596,280	201	1.78
Tamil Nadu	-129,510	251,440	120	1.91
Uttar Pradesh	-70,180	325,010	81	0.73

Source: AF-Mercados EMI analysis.

The bailout package also allows banks to finance operational losses and interest for the first three years on a diminishing scale. During these three years, the distribution companies are required to implement measures to cut their operational losses. PFC has offered short-term “transition loans” to distribution companies in Andhra Pradesh, Haryana, Punjab, Rajasthan, Tamil Nadu, and Uttar Pradesh. The loan terms have been offered with a three-year moratorium on interest payments and a seven-year term. The Rural Electrification Corporation has also offered transitional loans to boost liquidity in the short term.

Note

1. In Case 2 bids, developers are expected to submit a bid based on a specific fuel and specific location as opposed to Case 1 bids, where developers are free to choose fuel, location, and technology.

Reference

IDFC (Infrastructure Development Finance Company). 2012. “Power: Déjà vu.” PowerPoint Presentation, March 2012.

Inefficiency in the Power Sector

This chapter quantifies the inefficiencies in generation and distribution segment using two prominent methodologies, deriving an efficiency score for each state and supporting an analysis of how far they are from an optimal efficiency frontier.¹ Poor efficiency and productivity in operations have been a traditional problem in the state enterprise-dominated Indian power system. Poor productivity levels have also been a central problem hampering financial recovery of the utilities. Commentators across the board have argued that productivity must be improved on an urgent basis before costs are passed on to customers. Low productivity levels (a problem complicated by the poor availability and reliability of data) have blocked progress on financial recovery of utilities, rational tariffs, market development, objective regulation, and indeed, almost all aspects of electricity sector operation and service delivery.

Inefficiency in Generation and Distribution Operations

Measuring the productivity of utilities in the power sector is a complicated exercise. Evaluation thus has to consider certain key factors individually, whereas others must be evaluated in combination. In practice, productivity is measured by the ratio of the quantity of outputs produced to the quantity of inputs used. There are two types of productivity measure: total factor productivity (TFP) and partial factor productivity (PFP). TFP measures total output quantity relative to the quantity of all inputs used. Output can be increased by using more inputs, making better use of the current level of inputs, and by exploiting economies of scale or scope. PFP measures one or more outputs relative to one particular input (for example, labor productivity is the ratio of output to labor input).

PFP measures for the generation segment include:

- Plant load factor, which measures output (energy produced) as a ratio of capital input (the total energy that the installed capacity could have generated)
- Specific coal consumption (SCC), which measures coal consumed (the input) per unit of energy generated (the output)

- Specific oil consumption (SOC), which measures oil consumed (the input) per unit of energy generated (the output)
- Auxiliary power consumption, which measures energy consumed in the power plant’s auxiliary generation sources (the input) per unit of energy generated (the output)

However, TFP measures are important to consider, since none of these measures individually provides a comprehensive measure of the productivity of a power plant. Two prominent models are used to derive efficiency scores of states based on a combination of factors embodied in the TFP (appendix E):

Data envelopment analysis (DEA): DEA is a linear programming methodology used to measure the efficiency of multiple decision-making units when the production process presents a structure of multiple inputs and outputs. This method is commonly used for measuring the relative performance of similar utilities for which the presence of multiple inputs and outputs and nondiscretionary variables makes comparisons difficult. DEA identifies an efficient frontier made up of the most efficient firms in the sample and measures the relative efficiency scores of the less efficient firms in relation to the most efficient.

Stochastic frontier analysis (SFA): SFA is an econometric (parametric) method that estimates a cost or production frontier. The method is used to estimate the efficient frontier and efficiency scores. Because of its statistical nature, SFA allows for the inclusion of stochastic errors in the analysis and testing of hypotheses. However, the computations using this method are relatively complex and are highly dependent on the assumptions made in constructing the functional form for the utilities.

Operational Inefficiency in the Generation Segment

Some 80 thermal plants were selected for this analysis out of the 107 listed in the 2010 Central Electricity Authority (CEA) review, representing 91 percent of total power generating capacity in India. Plant-level analysis of various measures of partial productivity—SOC, SCC, station heat rate, auxiliary power consumption, plant load factor—is supported by a more comprehensive DEA-based measure of efficiency that considers the outputs, inputs, and nondiscretionary variables listed in table 4.1.

Table 4.1 DEA Efficiency Measurement Factors

<i>Output</i>	<i>Inputs</i>	<i>Nondiscretionary</i>
Total generation/ installed capacity	<ul style="list-style-type: none"> • Coal consumption • Oil consumption • Auxiliary consumption • Forced outages (the power plant “consumes” some hours of forced outage to deliver electricity, but as with other inputs, the lower the hours of forced outages, the better) 	<ul style="list-style-type: none"> • Planned maintenance • Age • Partial unavailability

Source: AF-Mercados EMI analysis.

The value of a DEA score ranges from 0 to 1, with 1 being the most efficient (within the sample). The input minimization approach allows a comparison across power plants of the extent to which the “linear combination” of inputs can be reduced for the production of one unit of output. Indexes for various states are weighted sums of the inputs. The weighted sum is normalized with respect to the outputs and nondiscretionary variables under consideration. Such an index is developed for each state. The weights are different for different states. The DEA selects weights such that the “best” aspect of the power plant’s performance gets prominence in the overall weight. For example, if a power plant is good at coal consumption and not so good at oil consumption, the model will give a higher weight to coal consumption for this plant. The DEA analysis would also indicate the extent to which each power plant needs to improve (reduce) its inputs, given industry best practices.

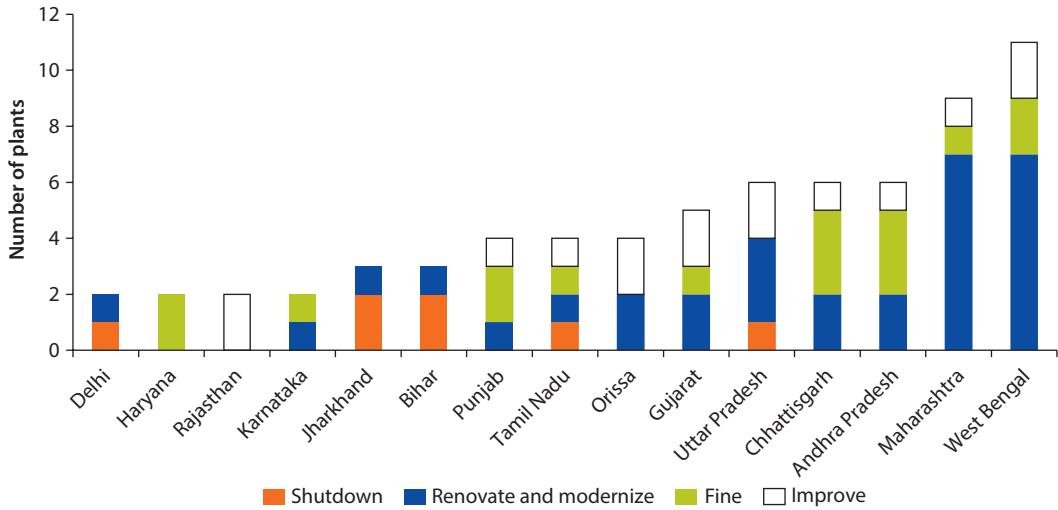
Comparison of the efficiency scores with and without consideration of non-discretionary variables leads to useful conclusions regarding their management—whether a power plant should be shut down, recommended for renovation and modernization, or allowed to continue operating in its present state.

- If a power plant obtains a high efficiency score when nondiscretionary variables are considered but a low efficiency score otherwise, the implication is that non-discretionary variables are weighing heavily on the performance of the plant. Such plants need to be retired or be considered for renovation and modernization. If the plant is old and its technology obsolete, the plant should be shut down.
- If the efficiency scores are low both with and without nondiscretionary variables, the value of the efficiency score will indicate whether the plant should be retired or renovated and modernized.
- If the efficiency scores are high in both circumstances, the plant is clearly doing well.

Based on the analysis of 69 state-owned thermal plants in 2010, it is evident that more than half of them should be either shut down or renovated and modernized. All plants in Bihar and Jharkhand fall into these two categories (figure 4.1).

Using the six worst-performing power plants as a case study, more than 2,750 million kilowatt hour of additional electricity could be generated if they operated at national station heat rate levels,² leading to a cost savings of about Rs 9 billion for the generation companies. This increase in efficiency would also enable the states to reduce their reliance on short-term purchases, for a further savings of about Rs 9 billion for the distribution companies. It would particularly benefit Uttar Pradesh and Bihar, which together accounted for more than 30 percent of total short-term purchases in 2011.

The savings would have been even greater, Rs 15 billion, if the six worst-performing plants operated at heat rates similar to those of the best plants.³ If the coal used in the inefficient plants were to be used efficiently, thus reducing the need for imported coal, the overall annual savings for the utilities could be on the order of Rs 20 billion. Even allowing for the fixed costs of the efficient plants, the utilities would still save Rs 15 billion (table 4.2).⁴

Figure 4.1 Thermal Power Plant Status by State

Source: AF-Mercados EMI analysis.

Table 4.2 Comparison of Inefficient Use of Fuel in Comparison with National Station Heat Rates and Most Efficient Plants

State	Plant	If plants are operating at national station heat rate			If plants are operating at efficient levels		
		Additional generation at national station heat rate levels	Additional savings potential	Savings for distribution companies after fixed costs	Additional generation at efficient levels	Additional savings potential	Savings for distribution companies after fixed costs
		Million units	Rs million	Rs million	Million units	Rs million	Rs million
Bihar	Barauni	184.57	548.17	369.14	249.53	741.12	499.07
Delhi	I.P. Station	204.08	732.63	408.15	298.35	1,071.07	596.7
Jharkhand	Patratu	515.41	1,484.37	1,288.52	753.5	2,170.07	1,883.75
Jharkhand	Chandrapura	262.35	755.56	655.87	610.71	1,758.85	1,526.78
Tamil Nadu	Ennore	432.26	1,257.87	2,377.42	711.68	2,070.98	3,914.23
Uttar Pradesh	Obra	1,169.45	4,268.49	4,093.07	2,083.59	7,605.09	7,292.55
Total		2,768.11	9,047.1	9,192.17	4,707.36	15,417.2	15,713.1

Source: AF-Mercados EMI analysis.

The key requirement is thus to have a rational and reasonable policy on efficient and regular renovation and maintenance of the plants. The decision to rehabilitate a plant should fully consider the economics and the operational and commercial realities involved in rehabilitation rather than being constrained by current policies on coal allocation and use. The DEA analysis provides a reasonable basis for evaluating high-level performance and can be used as a tool to evaluate and investigate performance.

Operational and Financial Inefficiency in the Distribution Segment

Analysis of the productivity of a distribution utility is more complicated. A distribution facility produces numerous outputs (unlike a generating station, which produces only electrical energy, although the literature distinguishes between peak power production and other-than-peak power production)—agricultural sales, commercial sales, domestic sales, industrial sales, and so forth. In addition, electricity sales during peak hours can be distinguished from sales during other-than-peak hours. The inputs that are used by a distribution company include labor, capital (transformers of various capacities, transmission lines at various voltage levels), and aggregate technical and commercial losses. Aggregate technical and commercial loss (AT&C) losses are defined as being “consumed” by the network to deliver energy to retail consumers.

The efficiency scores obtained from DEA models can be viewed as weighted sums of the inputs/outputs of the utilities being compared. The various performance parameters for the period 2006–10 are presented below:

1. Gap
2. 1/ collection efficiency (in percent)
3. Debtor days
4. Creditor days
5. Transmission and distribution (T&D) losses
6. Accumulated losses (sum of financial loss and the amount by which the subsidy received is less than the subsidy booked)
7. Energy deficit (in percent)
8. Power purchase cost per unit

All these parameters are inputs—the lower they are the better. Energy sold per unit of input was considered an output—because the higher it is the better. An input-oriented DEA model was used for development of the weights. The weights are variables in the DEA optimization model. The index is the weighted sum of all the eight parameters listed above. Weight restrictions were imposed by first running DEA without weight restrictions. This procedure identifies the states that one would want all other states to emulate. The states selected were Gujarat, Kerala, and West Bengal. Based on judgment and comparison of these states, weight restrictions were imposed on the models for other states.

Gujarat and West Bengal have consistently occupied one of the best three positions. Kerala has shown steady improvement over the entire period since 2006. The state has made improvements in its debtor and creditor days. It also exhibited considerable improvement in the ratio of its subsidy received to subsidy booked in the year 2007/08. Also, its T&D loss score improved in that year. Himachal Pradesh has performed relatively better due to high collection efficiency and low debtor days. On the other side, Uttar Pradesh, Bihar, and Jharkhand continued to be the worst performers over the entire time period. Rajasthan had a high subsidy receivable and high power purchase cost but has

Table 4.3 Top Five and Bottom Five in DEA Scores, 2006–10

	2006	2007	2008	2009	2010
Worst	Bihar	Bihar	Jharkhand	Jharkhand	Bihar
	Uttar Pradesh	Uttar Pradesh	Bihar	Bihar	Uttar Pradesh
	Jharkhand	Uttarakhand	Uttar Pradesh	Uttar Pradesh	Jharkhand
	Uttarakhand	Jharkhand	Uttarakhand	Uttarakhand	Tamil Nadu
	Orissa	Orissa	Orissa	Madhya Pradesh	Madhya Pradesh
Best	Himachal Pradesh	Delhi	Andhra Pradesh	Gujarat	Chhattisgarh
	Andhra Pradesh	Himachal Pradesh	Himachal Pradesh	West Bengal	Andhra Pradesh
	Kerala	Andhra Pradesh	West Bengal	Himachal Pradesh	West Bengal
	Gujarat	Gujarat	Gujarat	Chhattisgarh	Gujarat
	Assam	Kerala	Kerala	Kerala	Kerala

Source: AF-Mercados EMI analysis.

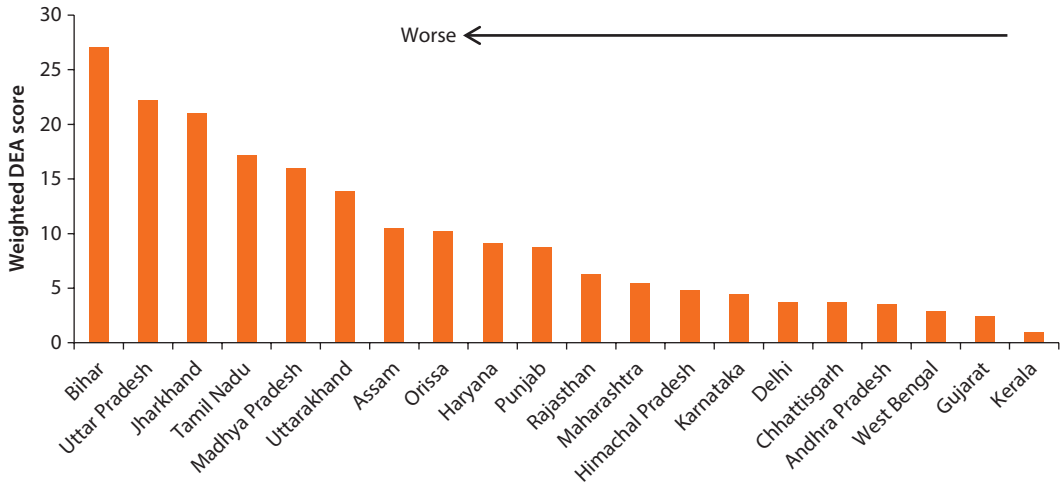
not done badly due to high collection efficiency and low debtor and creditor days. Orissa, on the other hand, suffered from high T&D loss and had consistently incurred losses (table 4.3).

In 2010, the most efficient state was Kerala, with a unity DEA score, followed by Gujarat and West Bengal. At the other end, Uttar Pradesh, Jharkhand, and Bihar report DEA scores higher than 20, representing the most inefficient performers (figure 4.2).

Operational inefficiency translates into financial inefficiency. The Financial Gap model analyses the determinants of inefficiency in Indian states. Stochastic frontier analysis has been used for benchmarking the operational performance of distribution utilities in India. Using parameters such as power purchase costs, debtor days, state government loans as share of total loans, and T&D loss, the model analyzes operational efficiency using the financial gap as the input parameter to be minimized. In the case of a financial gap, power purchase costs and debtor days are most critical. T&D losses, though weakly significant, are internalized in high power purchase costs. Unity represents efficiency, and the higher the score the more inefficient the contribution of the operational parameters to the financial gap.

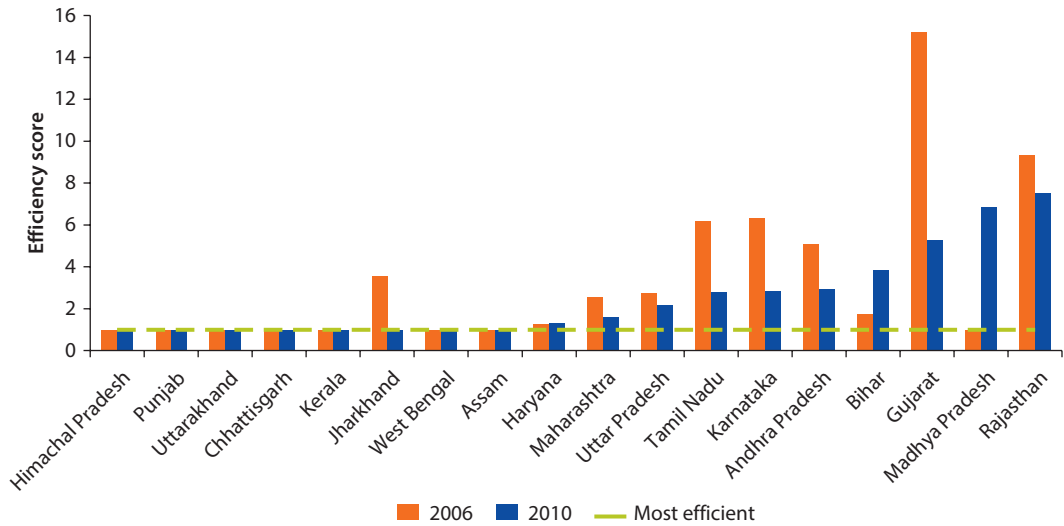
In 2010 there were 8 states reporting an SFA score of 1 out of the 16 major states considered in this analysis. Himachal Pradesh, Uttarakhand, and Punjab were the best placed, with operational parameters positively contributing to alleviating the financial gap. Many states also reveal movements across the five years. In Madhya Pradesh, operating parameters were performing well in 2006, while in 2010 the state emerged as one of the worst. The opposite situation is reported in Gujarat: the state went from a score of 15 for 2006 to 5 for 2010 (figure 4.3).

Figure 4.2 DEA Scores for States, 2010



Source: AF-Mercados EMI analysis.
 Note: DEA = Data envelopment analysis.

Figure 4.3 Efficiency Scores for States: Financial Gap Model, 2006 and 2010



Source: AF-Mercados EMI analysis

Notes

1. Transmission efficiency is not measured separately. Transmission losses (assuming that the transmission system is healthy) are governed by the nature of flows on the lines. If distribution companies do not perform power factor correction close to the demand centers, high reactive power flows could occur, overloading the lines and leading to higher losses on transmission lines. Transmission losses are therefore an externality caused in most cases by distribution systems. Also, data on transmission losses and availability are not reliably available. In addition, transmission system costs are insignificant from the point of view of their overall impact on the finances of state utilities.
2. The national operating heat rate was 2615.4 kilocalories per kilowatt hour (CEA 2011).
3. The station heat rate of the Dahanu plant was 2,285 in 2010.
4. Although the utility is required to pay the fixed costs for the use of third-party plants, because such plants are currently partially or wholly stranded for lack of coal, the savings for the nation is the entire amount, not just the net savings for the utility. Furthermore, if the coal is used in another partially utilized plant of the utility (or where the utility has a share and is paying fixed costs for underutilized capacity), the utility would garner the entire savings.

Reference

Central Electricity Authority. 2011. *Review of Performance of Thermal Power Stations 2009–10*. New Delhi: Central Electricity Authority, Ministry of Power.

One Solution Does Not Fit All

This chapter highlights the projected financial position of the Indian power sector for the period 2013–17. It also identifies the risk factors that may affect the projections, the key operational and financial parameters of selected states, and the critical parameters that need to be addressed to improve the performance of the states' power sectors.

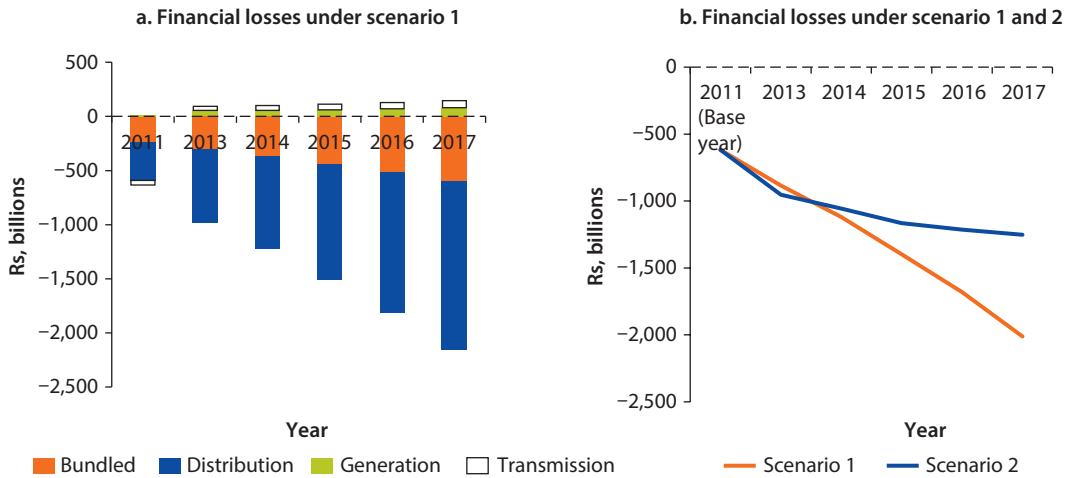
For each state, separate projections were prepared for the distribution, transmission, and generation segments (the assumptions for the financial projections are presented in appendix F). The profit and loss accounts along with the cash requirements were projected for bundled utilities and distribution companies for the period 2013–17. For bundled utilities, a combined projection was prepared. The projections were then aggregated to obtain an overall picture of India's power sector in 2017. For the generation and transmission segments, the projections are on a cost-plus basis (that is, they earn a return on equity) rendering them profitable ventures in each state. Sensitivity analysis is undertaken for each state to identify the most significant factors affecting the projected financials of the distribution segment. These factors include tariff increases, transmission and distribution (T&D) loss reductions, short-term power purchases, and debtor days.

For the distribution segment, financial projections were prepared for two scenarios:

Scenario 1 assumes that no tariff increase occurs during this period.

Scenario 2 assumes that the tariff rate is increased about 6 percent per year for all use categories except agriculture, mainly to meet increases in the cost of supply.

The annual financial losses of the sector (excluding subsidies) are projected to be Rs 2,013 billion in 2017 if business as usual continues compared to Rs 618 billion in 2011 (scenario 1) (figure 5.1). In the projections, while the generation and transmission companies earn profits the distribution companies continue to incur substantial losses. Even if tariffs rise by 6 percent every year to keep up with increases in the cost of supply, the annual losses in 2017 are projected to be Rs 1,253 billion (scenario 2).

Figure 5.1 Projected Power Sector Financial Performance

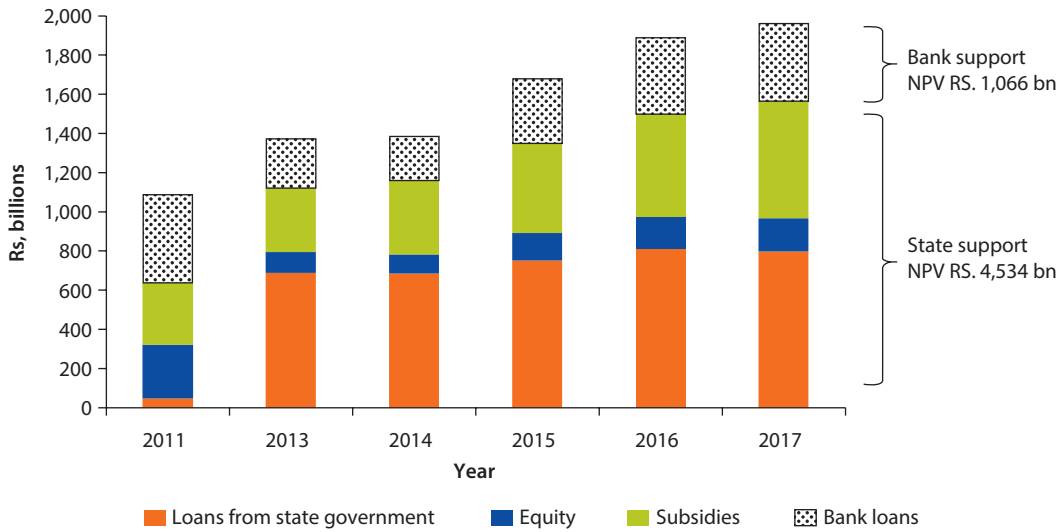
Source: AF-Mercados EMI analysis.

The large and increasing losses in the power sector will require considerable funding support, either by the banks or by state governments. In the recent past, funding has come predominantly from banks. However, because the risk profile of the power sector has deteriorated significantly, banks are reluctant to lend further, and many have reached their exposure limits. Without considerable deleveraging of power sector loans, banks will be unable to lend in the coming years to the same extent as before. The state governments are therefore assumed to have to bear a higher proportion of the financial burden to revitalize the power sector.

In scenario 1, state support to the power sector will increase on a net present value basis (figure 5.2). The power sector will require Rs 4.5 trillion in additional support, an increase of Rs 360 billion relative to scenario 2. In scenario 1, the projections analysis suggests that lending from the banks will be restricted to capital expansion and support from the financial sector will accordingly be scaled back. Lending will fall slightly, from Rs 450 billion to Rs 396 billion a year from 2013 to 2017. In 2017, lending from banks is expected to have a net present value of Rs 1.066 trillion. Altogether, annual funding support from state governments and banks will double, from just over Rs 1 trillion in 2011 to nearly Rs 2 trillion, or approximately 1 percent of India's projected gross domestic product (GDP) in 2017.

The financial performance of distribution companies in 2017 will vary greatly by state (Figure 5.3). Only four states are projected to be profitable without assistance from subsidies. Even with subsidies accounted for, only two additional states (Punjab and Gujarat) will be able to achieve profits. The best performing state is expected to be Himachal Pradesh with a profit of Rs 16 billion without subsidy. The worst performing states, by a large margin, are Rajasthan and Tamil Nadu, which are projected to lose Rs 248 and Rs 242 billion, respectively. Even

Figure 5.2 Projected External Support from All Sources for the Power Sector, 2011–17



Source: AF-Mercados EMI analysis.
 Note: NPV = net present value.

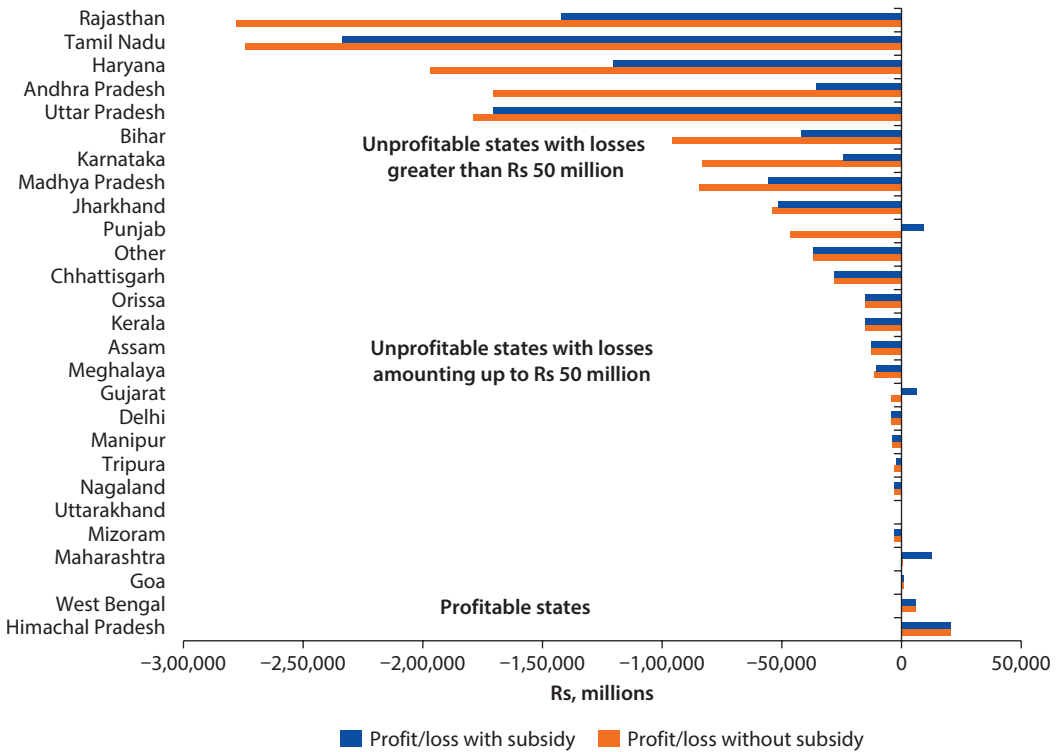
with subsidies, losses still remain very high, with Tamil Nadu having the highest losses with subsidy of all states, amounting to Rs 206 billion.

The gap between the average cost of supply and the average revenue earned per unit is the main driver behind these high financial losses and rising state support. According to the projections, in 2017 the gap will be less than 15 percent in only 10 states (figure 5.4).¹ Overall, between 2013 and 2017, 14 states will manage to reduce the revenue gap trend, while it will increase in 13 states. Only five states are projected to cover the cost of supply in 2017 (Goa, Himachal Pradesh, Kerala, Maharashtra, and West Bengal). The most dramatic change among these states is in Himachal Pradesh, which goes from moderate losses to profits during the period. Haryana and Meghalaya suffer the largest increase in the gap, signaling deteriorating performance. The gap in 2017 will be between 15 and 30 percent in six states. Of these states, Andhra Pradesh and Karnataka will both perform considerably better when subsidies are taken into account.

An analysis of state performance (figure 5.5) shows that the gap disappears for three states—Gujarat, Maharashtra, and Punjab—once subsidies are included. Andhra Pradesh’s financial gap in 2017 will decline from 22 percent without subsidies to 5 percent with subsidies. For the states that continue to receive subsidies (Bihar, Haryana, Rajasthan, and Tamil Nadu), the gap will decline somewhat, but will still remain high. For Punjab and Gujarat, the gap will disappear once subsidies are included.

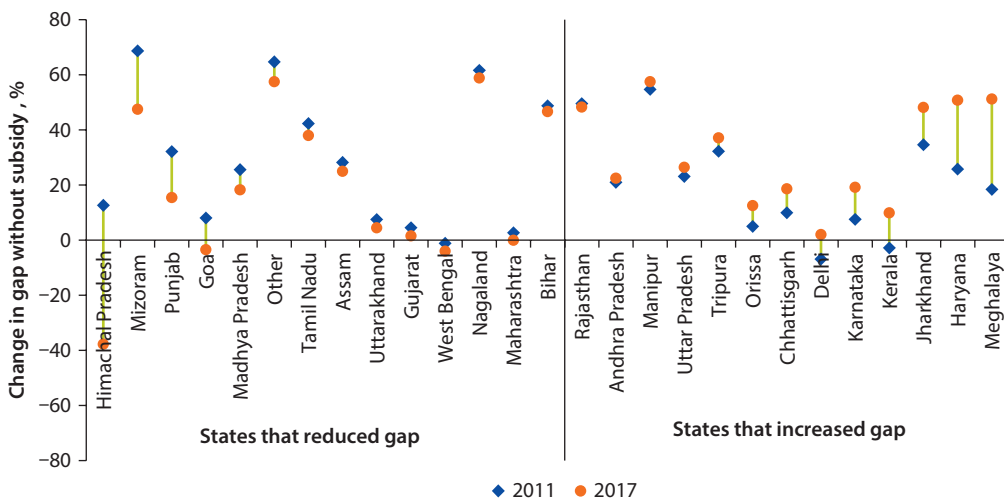
Most of the states in India suffer from distribution and collection inefficiencies, represented by high T&D losses and high debtor days.² The choices made for these parameters are important because they represent internal efficiency factors that can be addressed by the state and that will significantly help close

Figure 5.3 Projected PAT of Distribution Segment, 2017



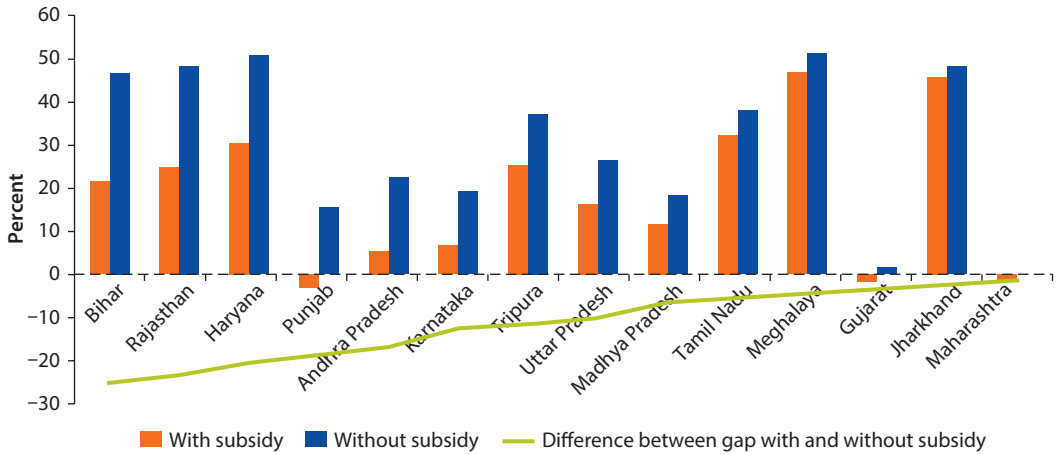
Source: AF-Mercados EMI analysis.
 Note: PAT = Profit after tax.

Figure 5.4 Projected Change in Gap without Subsidy, 2011 and 2017



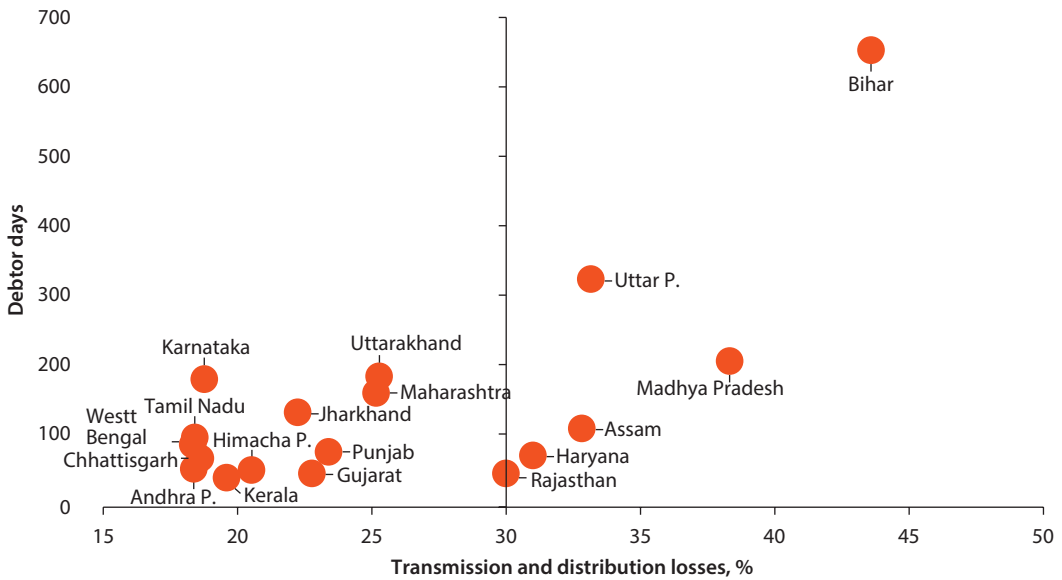
Source: AF-Mercados EMI analysis.

Figure 5.5 Gap with and without Subsidies, 2017



Source: AF-Mercados EMI analysis.

Figure 5.6 Debtor Days and T&D Losses



Source: AF-Mercados EMI analysis.

operating gaps. Figure 5.6 illustrates each state’s situation with regard to these key indicators of financial and technical efficiency. The figure is divided into two quadrants. The quadrant that needs attention is the one on the upper right: These states have more than 100 debtor days and more than 30 percent T&D losses. Three states are in this quadrant, Bihar, Madhya Pradesh, and Uttar Pradesh; Bihar shows the worst performance on these parameters.

Some States Will Perform Better Than Others

The state power sectors can be organized into three broad groups:

Group 1: Poor performers that need critical intervention to improve their financial performance:

- a) Reduction of T&D losses and debtor days (Bihar and Uttar Pradesh)
- b) Debt restructuring (Rajasthan and Tamil Nadu)
- c) Reduction of power purchase costs (Andhra Pradesh and Kerala).

Group 2: Top performers (Gujarat, Maharashtra, and West Bengal)

Group 3: Poor performers (Jharkhand, Punjab, and Orissa) for which the turnaround may be easier than other states as the result of external factors such as the consumer mix and resource endowments.

The state power sectors' problems demonstrate a regional pattern. The southern states face high power purchase costs (which will be addressed by southern grid connectivity), whereas the northern and north-east states all need to improve their T&D losses and collection efficiency.

Group 1: Poor Performers That Need Critical Interventions to Improve Financial Performance

States that need reductions of T&D losses and debtor days

Bihar and Uttar Pradesh suffer from poor efficiency as measured by high T&D losses and debtor days, both of which must be addressed if the states are to achieve a financially sustainable future.

Bihar: Bihar is home to the worst-performing power utility in India. Per capita power consumption in the state is about 107 kilowatt hours against an all-India average of 734 kilowatt hours. About 65 percent of households in Bihar do not have access to electricity. The weak operational performance of the sector can be attributed to high T&D losses (44 percent in 2011). The losses are due to rampant unmetered supply (nearly 40 percent of 33 kilovolt and 11 kilovolt feeders are unmetered) leading to misuse of energy, lack of billing discipline, widespread electricity theft, poor high tension/low tension (HT/LT) ratios (caused by poor domestic and agricultural networks and lack of investment in HT lines), and an inefficient distribution network. The poor operational performance of the sector is compounded by its dismal financial performance. The gap between average cost of supply (ACS) and average revenue realized (ARR) is one of the highest in the country (in 2011, the gap was 119 percent of ARR). Power purchases have increased from 5,900 million kilowatt hours in 2003 to almost 10,000 million kilowatt hours in 2010, and power purchase costs accounted for 66 percent of total sector costs in 2010–11. This can be attributed to many reasons: No new generation unit has been constructed in the past 25 years, 70 percent of the existing generation capacity went to Jharkhand after bifurcation in 2000, the existing capacity is operating at a 27 percent plant load factor, and operational efficiency is low (the station heat rate of the existing plants is almost double the national average). However, subsidies as a percentage of revenues from sale of power have been consistently decreasing and have

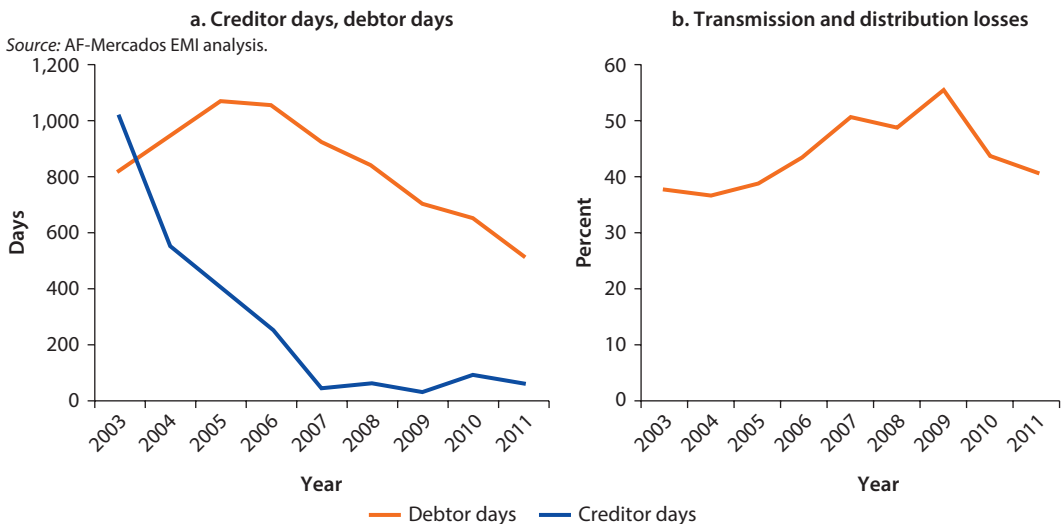
fallen from 75 percent in 2005–06 to 46 percent in 2009–10. Tariff increases have been sporadic and marginal since 2007, and the sector has one of the worst debtor turnover ratios in India, which implies both issues of collection efficiency and bad debts not being written off. Figure 5.7 shows historically high debtor and creditor days and T&D losses of more than 40 percent. Reduction of both is crucial for improving the sector’s performance.

In Bihar the average cost-average revenue realized (AC-ARR) gap is expected to remain extremely wide unless significant tariff increases or T&D loss reductions are achieved. It will, however, diminish over time because ARR is expected to grow at a higher rate than AC, largely as a result of a decline in the growth rate of power purchase costs in the latter part of the period. The state has engaged in private partnerships for boosting generation in the 12th Plan. A transmission-strengthening and expansion project is being implemented by a joint venture between Bihar Transmission Company and Power Grid and various measures are being taken to reduce T&D losses.

The power sector in the state is expected to require support through subsidies, additional state equity, and additional state loans to the extent of about 3 percent of state GDP between 2014 and 2018.

Sensitivity analysis shows that although losses are sensitive to a tariff increase, a buildup in current assets resulting from the high debtor days will counteract any improvement in revenues. Hence, improvement in debtor days is the key to improving performance. Given the high debtor days, even an annual two-month reduction in debtor days results in only a 19 percent reduction in the operating cash gap at the current 6 percent tariff increase levels. Therefore, the state can significantly reduce its financial gap with aggressive efficiency improvements and sustained 6 percent tariff increases

Figure 5.7 Efficiency Indicators for Bihar, 2003–11

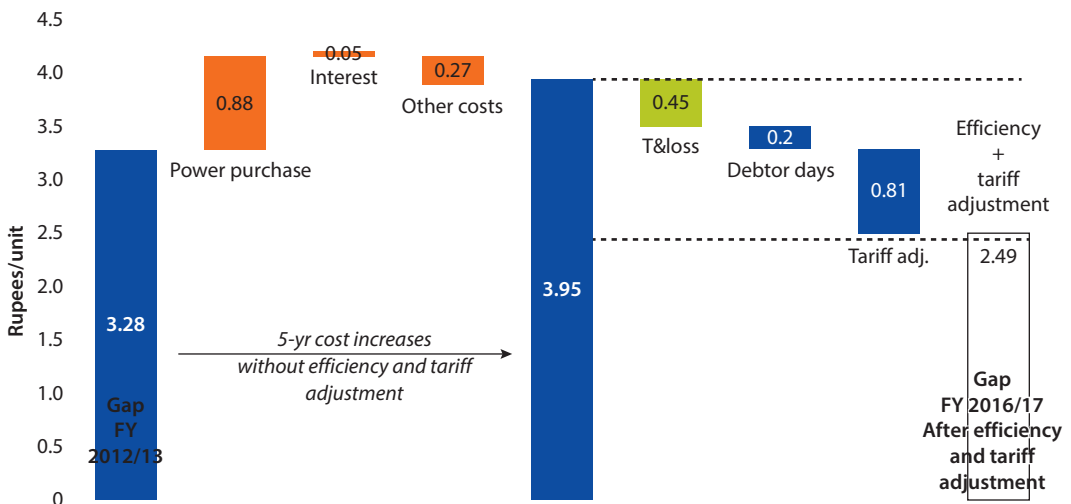


(as shown in figure 5.8). In the past, the tariff structure in Bihar remained constant; the state began releasing annual tariff orders in 2010. In fiscal 2012, the average weighted tariff was Rs 5.51 per kilowatt hour, up from Rs 5.33 per kilowatt hour in fiscal 2003.

Uttar Pradesh: Uttar Pradesh must confront issues similar to those in Bihar. High T&D losses have plagued the sector since before the reform era. The state has made limited improvements since the latter half of the decade, but T&D losses still remain higher than India’s average. Debtor days remain at 300, and creditor days have shown a massive increase to more than 500 days in 2009–10, meaning that the distribution companies are having enormous trouble with debt repayment (figure 5.9). This problem has a ripple effect on the rest of the value chain—the historical debtor day average of the generation companies in Uttar Pradesh (UP) is 245 days, and that of the transmission companies is 300 days.

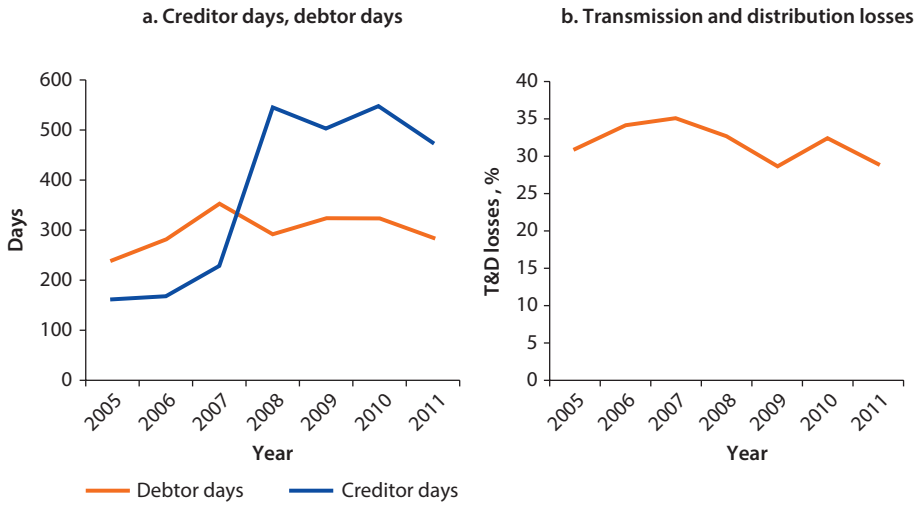
UP is highly dependent on external power purchases, which were more than twice the state’s own generation capacity in 2010. UP’s poor collection efficiency affects not only the state’s utilities but also central generating stations and power markets. In light of the 2012 blackout in India, the states’ failures to adhere to their allotted withdrawal amounts have come to the fore. UP was one of the few states specifically singled out by the state electricity regulatory commission (SERC) for not maintaining grid discipline despite repeated warnings. In June 2012, UP withdrew 3.762 billion kilowatt hours compared with its allotted share of 3.011 million kilowatt hours. The average over withdrawal per day was 25 million kilowatt hours, which remains unpaid. UP desperately requires an intra-state availability-based tariff to allow the state utility to pass the burden of these high-cost purchases caused by unscheduled interchange to the entities that overdraw from the grid.

Figures 5.8 Reduction of the Gap (without Subsidy) in Bihar with Efficiency and Tariff Improvements



Source: AF-Mercados EMI analysis.

Figures 5.9 Efficiency Indicators for Uttar Pradesh, 2005–11



Source: AF-Mercados EMI analysis.

The UP power sector can improve its efficiency by reducing T&D losses from 33 percent in 2010 to 20 percent in 2017, reducing debtor days by 30 days per year between 2014 and 2017, and by regular tariff adjustments of 6 percent per year between 2014 and 2017. Figure 5.10 shows the improvement that the state is projected to achieve via these mechanisms.

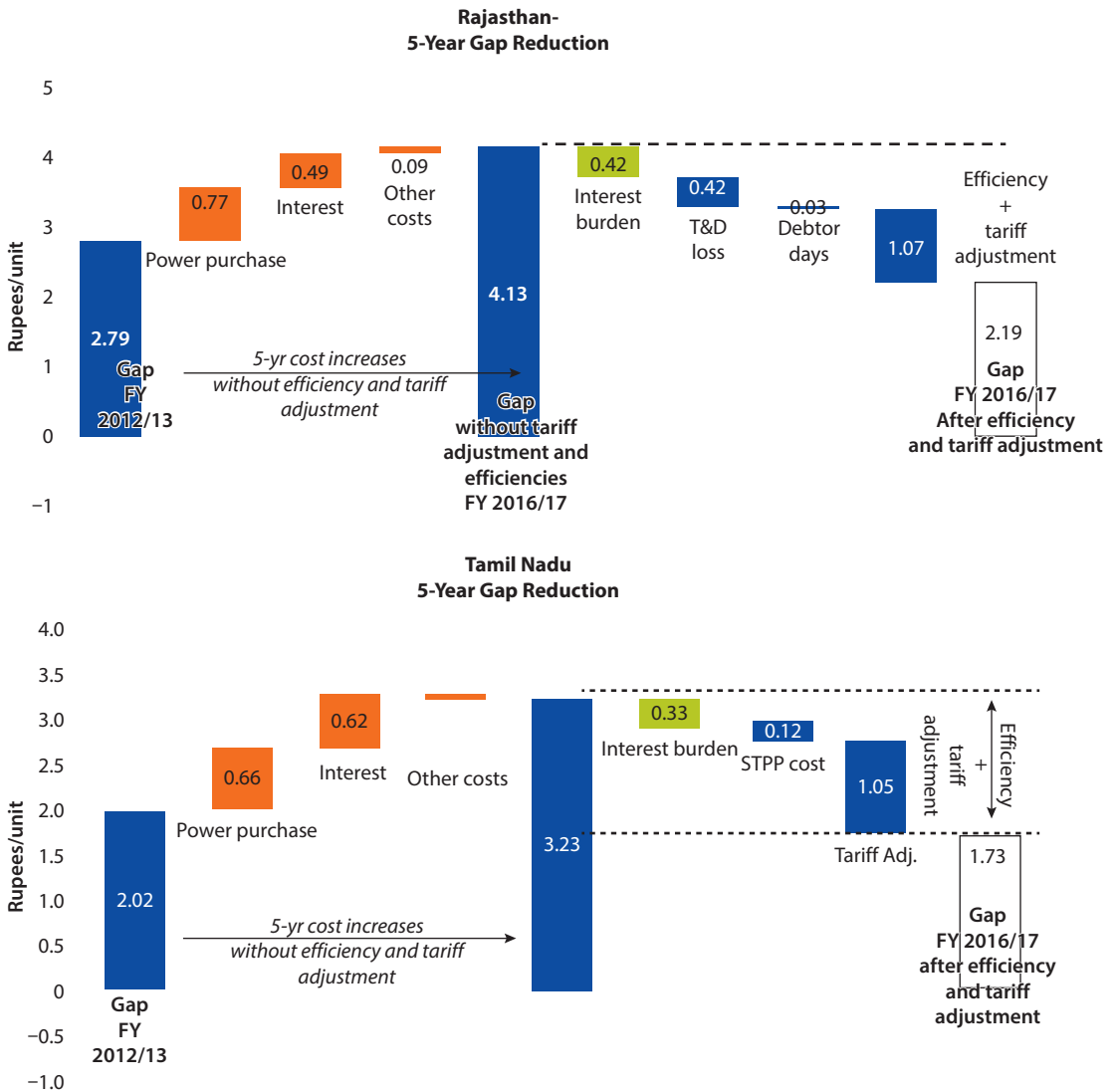
States for Which Debt Restructuring is Crucial to Improving Financial Performance

Rajasthan and Tamil Nadu: Rajasthan and Tamil Nadu are reeling under substantial interest rate burdens, weakening the finances of their power sectors significantly. Power sector debt in both states increased at a compound annual growth rate of about 40 percent during 2006–10. The two states together accounted for 26 percent of the country’s total power sector debt in 2010 (compared with 16 percent in 2006). Rajasthan has the largest share of debt as a percentage of state GDP (20 percent) followed closely by Tamil Nadu. In Tamil Nadu, borrowing from financial institutions showed continuous growth, with a 150 percent increase in 2009–10. The factors responsible for the poor performance of the sector in both states can be attributed to high proportions of subsidized consumers (especially agricultural); unrevised tariffs for long periods, thereby hurting revenues; and huge power purchase costs.³

In Rajasthan, T&D losses contribute to the sector’s poor performance, in addition to the reasons discussed above. T&D losses decreased from 32 percent in 2006 to 30 percent in 2009, but there is still substantial room for improvement. In comparison, T&D losses in Tamil Nadu have been consistently low at 18 percent.

The power sector debt in both states needs to be restructured to ease their financial distress and give them the much-needed breathing space to increase

Figure 5.10 Reduction of the Gap (without Subsidy) over 5 Years with Efficiency and Tariff Improvements



Source: AF-Mercados EMI analysis.

Note: FY = fiscal year; T&D = transmission and distribution.

operational efficiency. The burden of debt in both states is so high that the financial gap cannot be overcome by tariff adjustments and efficiency improvements alone. Sensitivity analysis for Rajasthan shows that if interest rates come down by close to 1.2 percentage point annually, the financial gap will decrease by 23 percent (with annual tariff hikes of 6 percent) (table 5.1). If the interest rate were to remain unchanged and the 6 percent tariff increase were coupled with a 2 percent annual improvement in efficiency, the reduction in the financial gap would only be 14 percent (table 5.2). Similar

sensitivity to interest rates is seen In Tamil Nadu: If interest rates decline by around 1 percentage point, the financial gap decreases by 23 percent (at annual tariff hikes of 6 percent) (table 5.3).

Table 5.1 Rajasthan: Sensitivity Analysis of Cumulative Financial Gap to Decline in Interest Rate, over 5 Years

		<i>Tariff rate increase (%)</i>					
		<i>(984,432)</i>	<i>0</i>	<i>3</i>	<i>6</i>	<i>8</i>	<i>10</i>
Interest rate reduction (percentage points)	-0.3	25	16	7	0	-8	
	0.0	18	9	0	-7	-14	
	0.3	12	3	-6	-13	-20	
	0.6	5	-3	-12	-18	-25	
	0.9	-1	-9	-18	-24	-30	
	1.2	-6	-14	-23	-29	-35	

Note: Percent change in the cumulative financial gap.

Table 5.2 Rajasthan: Sensitivity Analysis of Cumulative Financial Gap to Tariff Rate and Efficiency Improvements, over 5 Years

		<i>Tariff rate increase (%)</i>					
		<i>(984,432)</i>	<i>0</i>	<i>3</i>	<i>6</i>	<i>8</i>	<i>10</i>
Interest rate reduction (percentage points)	-1.0	24	16	7	1	-6	
	0.0	18	9	0	-7	-14	
	0.5	15	6	-3	-10	-18	
	1.0	13	3	-7	-14	-21	
	1.5	10	0	-10	-18	-25	
	2.0	7	-3	-14	-21	-29	

Table 5.3 Tamil Nadu: Sensitivity Analysis of Operating Cash Gap to Financial Improvements, over 5 Years

		<i>Tariff rate increase (%)</i>					
		<i>(949,516)</i>	<i>0</i>	<i>3</i>	<i>6</i>	<i>8</i>	<i>10</i>
Interest rate reduction (percentage points)	-0.3	18	12	6	2	-3	
	0.0	12	6	0	-4	-8	
	0.3	6	0	-6	-10	-14	
	0.6	0	-5	-11	-15	-19	
	0.9	-5	-11	-16	-20	-24	
	1.2	-11	-16	-21	-24	-28	

Source: AF-Mercados EMI analysis.

Analysis shows that for Rajasthan, aggressive efficiency improvements coupled with no interest payments for three years could bring the financial gap down from Rs 2.79 per kilowatt hour in 2012/13 to Rs 2.23 per kilowatt hour in 2016/17 (figure 5.10, panel a). This effect is possible only with the moratorium on interest payments because of the huge interest burden, which stood at Rs 1.24 per kilowatt hour as of 2012/13. Without a debt-restructuring plan, it will be difficult for Rajasthan to shrink the gap by any significant percentage. Similarly, even with aggressive efficiency improvements (figure 5.10, panel b), Tamil Nadu can cut the gap by only a small amount, from Rs 2.02 per kilowatt hour in 2012/13 to Rs 1.80 per kilowatt hour in 2016/17. This is because of the huge interest burden, which stood at Rs 0.9 per kilowatt hour as of 2012/13.

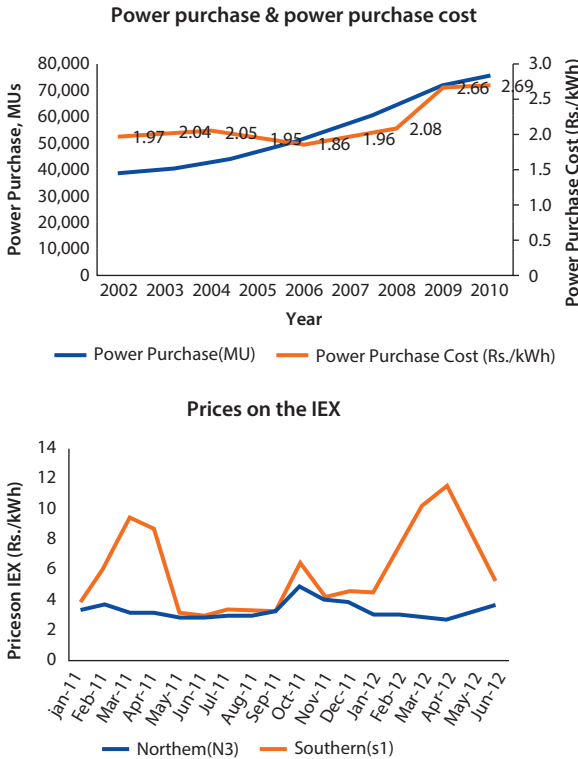
The Case for Increasing Energy Supplies at Low Power Purchase Cost

Andhra Pradesh: Overall, the power sector in Andhra Pradesh (AP) is operationally efficient. The state has been able to reduce T&D losses significantly (from 23.29 percent in 2007/08 to 18.37 percent in 2009/10), a result that is mainly attributable to the efficiency of distribution companies and the upgrading of the distribution network from LT to HT lines (the HT/LT ratio increased from 0.55 in 2005/06 to 0.61 in 2009/10). The state also has consistently high levels of plant availability (>92 percent), a plant load factor in excess of 88 percent, and low levels of auxiliary consumption. The utilities have been performing well with regard to collection efficiency (both debtor and creditor days remained well below 100 between 2005/06 and 2009/10). The sector's financial performance has been stable.

Subsidies are a major determinant of the state's power sector performance, accounting for 25 to 30 percent of the distribution revenue. Subsidies apply to two circumstances: a financial subsidy to families below the poverty line and to agriculture and operational subsidies for power purchases. Agriculture is a major consumer of power in the state (accounting for 31 percent in 2010) and supply to agricultural consumers increased by around 70 percent between 2000 and 2010. The state government introduced free power supply to agricultural consumers in 2004, which led to an obvious increase in the subsidy burden. Also, the state has been increasingly reliant on power purchases, which increased from 0.81 percent in 2007 to 4.52 percent in 2010, with a significant spike of 7.11 percent in 2009 (figure 5.11). The spike was mainly caused by increases in the amount of energy input into the system before the elections and by issues of southern grid connectivity that led to soaring power prices.

Kerala: Kerala has not unbundled its electricity sector, but it has consistently performed well. Despite an apparent lack of urgency in implementing key reforms enshrined in the Electricity Act, Kerala has had one of the best performing electricity sectors in the country. The Power Finance Corporation (PFC) recently selected the Kerala State Electricity Board (KSEB) as the second best power utility in India on financial and technical ratings. The Indian Chamber of Commerce placed Kerala as the third best performer in the Indian power sector—KSEB ranked first for revenue management and technical knowhow. Kerala also received the National Energy Conservation Award for its energy conservation efforts.

Figure 5.11 Andhra Pradesh: Power Purchases



Source: AF-Mercados EMI analysis.
 Note: IEX = Indian Energy Exchange; kWh = kilowatt hour; MU = million units.

Kerala has reduced its aggregate technical and commercial loss (AT&C) losses to 17.7 percent, better than most states in India, and T&D losses have decreased every year since 2001. Kerala has earned profits consistently, and has had prudent debt management. Total debt has fallen every year, despite KSEB facing rising power purchase costs. All connections are metered, and theft of electricity is practically nonexistent.

Kerala has taken many positive steps to increase operational efficiency:

- A *New State Power Policy* was put into effect in 2008, whereby KSEB (despite not explicitly unbundling) will functionally and financially be disaggregated and organized into three business entities: the Generation Profit Centre, Transmission Profit Centre, and Distribution Profit Centre with a corporate office for coordination. The Kerala government initiated the incorporation of KSEB as a fully owned government company under the Companies Act of 1956. The company is to be named Kerala State Electricity Board Limited.
- *KSEB invested in its subtransmission and distribution network, not only in expanding it but also in incorporating IT infrastructure.* The biggest success story in transmission has been the establishment of a state-of-the-art state load dis-

patch center compatible with Supervisory Control and Data Acquisition (SCADA) and associated communication infrastructure. Adoption of load flow software for transmission system planning has also been remarkable. KSEB has also taken up substantial works under the Accelerated Power Development and Reform Programme (APDRP), Restructured-APDRP (R-APDRP), and Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) schemes for expanding and augmenting its distribution network. Various demand-side management and energy efficiency initiatives have also been successful, such as the 1 million compact fluorescent lamps campaign, the upgrading of tamper-proof meters, and the formation of antipower theft squads with independent special courts.

- *Focus on metering, billing efficiency, and customer service.* Kerala enjoys 100 percent metering, and older faulty meters are being replaced with modern tamper-proof electronic models. In addition, KSEB is modernizing its systems and internally developing open-source software—such as customer-friendly electric billing (ORUMA), accounting software (SARAS), and online portal for consumer payments and grievance redressal. These efforts have led to improved service quality, billing efficiency, transparency, and financial savings. KSEB enjoyed collection efficiency of 97 percent in FY2011, a testament to its achievements.
- *Investment in its employees.* KSEB has worked hard to improve employee efficiency and satisfaction through well-designed technical, information technology (IT), and financial training to all officers and staff and by implementing performance-based incentives and improving grievance redressal and pension schemes for employees.
- *Effective state regulator.* Despite political backlash that has kept the state from passing many of the stipulations of the Electricity Act, 2003, such as unbundling, the Kerala State Electricity Regulatory Commission (KSERC) has grown into an effective regulatory agency overseeing a well-performing power sector, as evidenced by them unanimously winning the International Plasma Products Industry Association (IPPIA) Power Award for best SERC in 2013. KSERC has been relatively diligent on issuing tariff orders in 10 of the last 13 years (which ranks them fifth among all states in this regard), and they increased tariffs in three of the past 6 years (FY2006, FY2008, and FY2013).

Kerala has an installed capacity of 3,828 megawatts, half of which is state-owned hydro. For years, Kerala has been able to supply electricity at low cost due to the high proportion of hydro generation in the state's energy mix. Kerala has also earned consistent profits. But the current challenge is to meet the rising demand. The generation mix has become less favorable, and costs have risen as a result. Since the passage of the Forest Conservation Act of 1980, many potential new hydro sites have become unviable, so new capacity added has been mainly thermal-based, which has raised the supply cost. In addition, in a given year monsoon failure can greatly reduce the hydro generation on which the state depends. The failure of monsoons in 2009 and 2012 forced KSEB to procure substitute power for shortfalls in hydroelectric production, without adequate compensation through tariff revisions. All the while, consumption has

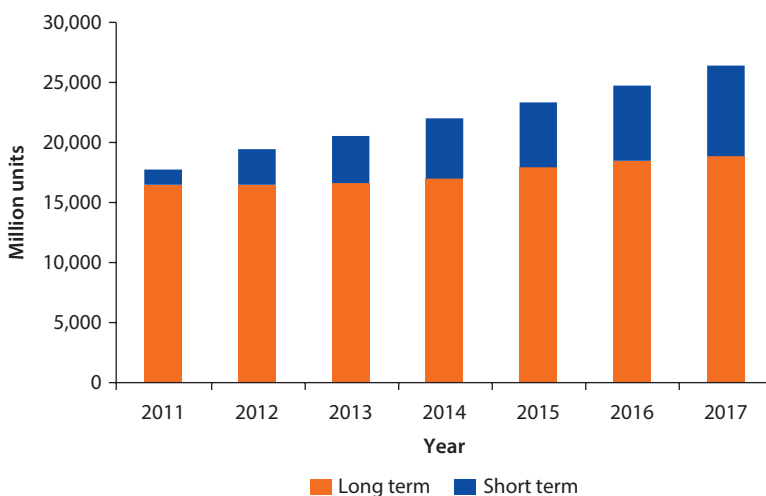
been rising rapidly. To meet rising demand and meet the demand-supply gap, Kerala has been forced to purchase power from the short-term market. Yet the maximum import capability of the southern grid for Kerala is only 1,500 megawatts, so Kerala has also needed to rely heavily on its liquid fuel stations, which have a variable cost of about Rs 10.50 per kilowatt hour.

And financial pressures are mounting. KSEB received a small subsidy in 2011 for the first time, and has requested that KSERC treat the revenue gap as a regulatory asset for the upcoming tariff period, because tariff increases have not kept up with rising costs. The revenue gap was expected to be more than Rs 21 billion in 2012, and more than Rs 32 billion in 2013. Tariff increases have not kept up due to the unexpected variation in power purchase costs, particularly in the failed monsoon years.

In the projection period, Kerala’s performance is critically linked with power purchase costs. Over the next five years, there is no expected capacity addition in the state. KSEB will thus likely increase short-term power purchases and production from expensive diesel generation. The short-term power purchase rate is expected to rise. By 2017, up to 30 percent of power purchase could be short term (figure 5.12). Grid integration after 2014–15 could lower power costs on the spot market, since the supply of power available to southern states will rise, but will still be higher than power procured long term. Without efficiency and tariff adjustments, the gap will rise to Rs 1.83 per kilowatt hour (figure 5.13).

If Kerala can reduce its dependence on short-term power purchase by Rs 50 a year, it could reduce the gap to Rs 36 in 2018, which would mean that the tariff shock to close the gap would be very small.

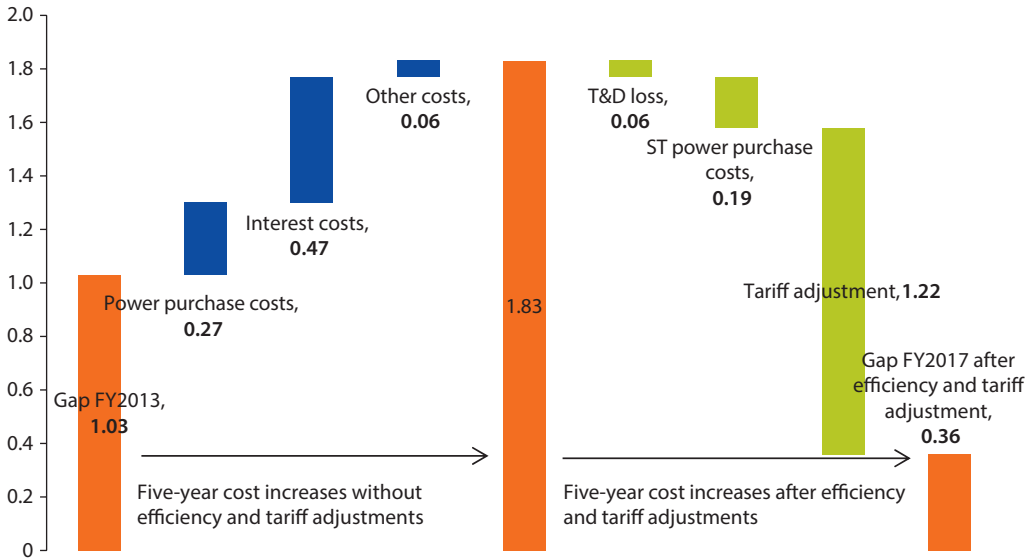
Figure 5.12 Estimates for Short- and Long-Term Power Requirement in Kerala



Source: Mercados EMI.

Note: Data for 2011 and 2012 are estimates and not actual values, and for 2013–2017, projections.

Figure 5.13 Five-Year Gap Reduction, Kerala



Source: Mercados EMI.
 Note: T&D = transmission and distribution.

Group 2: Top Performers⁴

West Bengal and Gujarat: West Bengal and Gujarat are two of the better-performing states with regard to the power sector. Both states have unbundled utilities that have become profitable mostly through good operational performance and regular tariff revisions and because a significant proportion of their customer bases is the industrial sector. Early in the reform process, both states adopted key measures to improve the operational performance of the utilities, which in turn improved their financial performance.

Gujarat has a well-functioning power sector that unbundled its state electricity board in 2005 into a generation company, a transmission company, and four distribution companies and is among the leading states in undertaking power sector reforms. Before unbundling subsequent to the Electricity Act 2003 mandate, the state had taken steps to bolster the finances of the sector through debt restructuring, reducing T&D losses through better vigilance, and improving operational efficiency by separating supply to farmers from supply to rural households under the Jyotigram Yojana program (2003) (see box 5.1). Eventually the state embarked on unbundling the power sector, and since then the state utilities have developed and sustained strong institutional capacity and are following corporate governance norms.

West Bengal’s transmission segment has been one of the best performers in the country. Since unbundling in 2007, it has maintained system availability rates of greater than 99 percent and has reduced intrastate transmission losses each

year. It has also invested in system expansion to maintain its performance and profitability. In the distribution segment, a 100 percent metering rate has been achieved in all customer categories except for agriculture, for which it is 92 percent. The tariff reform process has yielded a gradual reduction in cross-subsidies, while keeping tariffs to levels that are among the lowest in the country. Provision of power to the agricultural sector, which in many states is a leading cause of financial and operational problems, is well managed. The tariff rates for the agricultural sector in West Bengal are among the highest in India. Subsidies are minimal and effectively targeted. The utilities have also taken various initiatives to improve and sustain the efficiency standard. The distribution company has been actively trading energy on the short-term market, which has been a significant source of revenue in recent years. The state has also conducted a successful rural electrification drive (the access rate increased from 46 percent in 2008 to 95 percent in 2011). See box 5.2 for additional information.

Box 5.1 Feeder Segregation: The Jyotigram Yojana in Gujarat

In September 2003, the government of Gujarat pioneered a bold scheme, the Jyotigram Scheme (JGS), to separate agricultural feeders from nonagricultural feeders for domestic and industrial use. JGS was launched initially in eight districts of Gujarat on a pilot basis. Feeders supplying agricultural connections were separated from the supply to commercial and residential connections at the substation level, and these agricultural feeders were metered to improve the accuracy of energy accounting. The early results were so encouraging that the scheme was extended to the entire state by 2004.

Under the JGS, the villages were provided with a 24-hour power supply for domestic uses, as were schools, hospitals, and village industries. Farmers began getting 8 hours of power per day, but at full voltage and on an announced schedule. JGS has not only met its primary objective of quantity and quality of supply for nonagricultural purposes but has spurred non-farm economic enterprises and kept power subsidy to agriculture under check. JGS also empowered the state distribution utilities to undertake better load management with regard to agriculture consumers, through planned supply rotation on agriculture-dominant feeders and help in better management of peak demand.

Box 5.2 The West Bengal Power Sector

Among Indian states, West Bengal has been a leader in the implementation of reforms. Since unbundling its State Electricity Board in 2007, all of the successor entities have been profitable in each year. Only the distribution company has received a small government subsidy (in 2010/11) targeted toward the poorest of consumers. Before reforms, the West Bengal State Electricity Board was inefficient and loss making, requiring budget support to sustain its op-

box continues next page

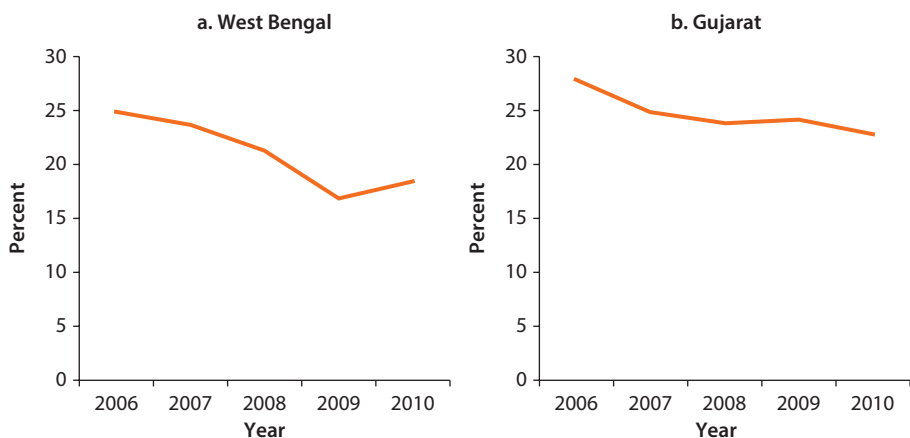
Box 5.2 The West Bengal Power Sector *(continued)*

erations. West Bengal's approach to reform was gradual. Before unbundling, West Bengal reviewed the strengths and weaknesses of the existing framework and identified best practices from international experience and across India, developed a financial and institutional restructuring plan built on credible data, and engaged in intensive stakeholder consultations throughout the process to ensure commitment to the reform agenda at all levels.

The West Bengal State Electricity Board adopted computerized billing, 100 percent feeder metering, strict monitoring, and vigilance activities to prevent electricity theft, augmented by nearly 100 percent metering of consumers. The government also induced changes in the top management at the West Bengal State Electricity Board by appointing seasoned bureaucrats with strong management and business acumen. In addition, West Bengal has been alone among states in consistently raising tariffs. From fiscal 2008 through fiscal 2011, tariffs were raised every year. In fiscal 2012, the pace of reform hit a snag when the distribution company was unable to obtain a tariff increase from the State Regulatory Commission. Given the deteriorating state of the power sector and pressure from various stakeholders, the regulator finally increased the tariff. The distribution company submitted a tariff petition proposing a 6 percent hike in the average tariff by fiscal 2014.

In West Bengal, the supply-demand situation has stabilized following reforms, hovering around a deficit of 3 percent at the end of the last decade. West Bengal has an installed capacity of 4,920 megawatts, composed primarily of thermal power resources. In 2010, energy demand was 33,853 million kilowatt hours while energy availability was 32,919 million kilowatt hours. The peak and energy deficits in the state have been consistently low. T&D losses have also been low (18.33 percent in 2010) (figure 5.14). The state has one of the best high tension/low tension (HT/LT) ratios in the country (mostly attributable to its high

Figure 5.14 T&D Losses in West Bengal and Gujarat



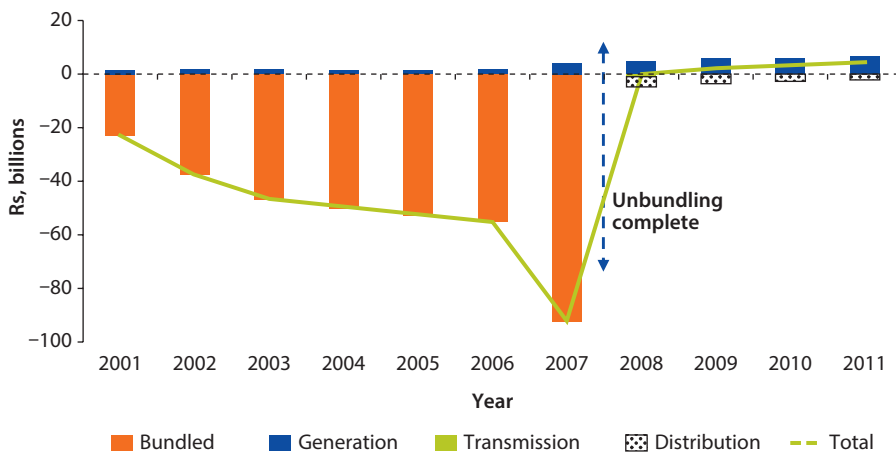
Source: AF-Mercados EMI Analysis

industry share in the consumption mix). Both T&D losses and agricultural consumption have fallen significantly (in the distribution segment, aggregate technical and commercial losses have fallen from 34 percent in 2006 to 26 percent in 2009), which indicates that there has been no masking of losses. However, despite a significant increase in installed capacity, power purchases in the state have risen, indicating inefficiency in generation.

In Gujarat, installed capacity has increased, with the last major capacity addition occurring in 2010, consisting mainly of gas-based power plants. Both peak deficit and energy deficit in the state have been high but have shown a decreasing trend. Consistent and considerable capacity additions have led to reductions in energy deficits. Efficient performance of the distribution companies has kept T&D losses low. In Gujarat, industry constitutes 45 percent of energy consumption. The high share of industry in the consumption mix has ensured a high HT/LT ratio. Concurrently, sales to agriculture have remained constant over the years. The state has also seen increasing power demand, reflected in increasing power purchases.

The generation segment in West Bengal has been profitable; however, profits have been falling recently as the result of operational inefficiency of the plants, with a plant load factor of 70.83 in 2011 (PFC). The transmission company in West Bengal has performed well since inception. It has maintained an average net profit margin of 23 percent. Revenues and costs have moved in line with each other. Debtor days have fallen from 90 to 60 days in the last four years since 2007. Creditor days have been increasing since the beginning of restructuring; however, they fell to close to 30 days in 2010/11. Since the implementation of financial restructuring in 2007, accumulated losses sector-wide have turned from negative to positive (figure 5.15). The state planned power purchases efficiently, through improvement in efficiency and enhancement in generation capacity, thus successfully reducing the financial burden of short-term power purchases; and

Figure 5.15 West Bengal: Accumulated Profits and Losses, by Segment



Source: India Power Sector Review Database.

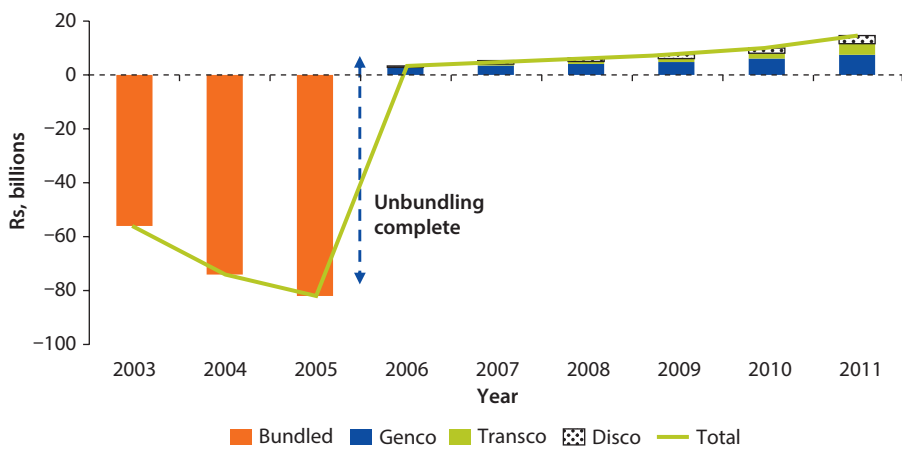
costs have not increased significantly in recent years. Until recently, tariff determination in the state was almost free from political interference. As a result, average revenue now exceeds average cost. In 2011, West Bengal achieved a revenue surplus of Rs 0.44 per kilowatt hours.

In the last four years, the total debt in the power sector has actually declined at a compounded annual growth rate (CAGR) of 8 percent. The net worth of the distribution companies has been rising (implying that with greater independence, they are able to meet their funding needs) and contributes significantly to capital. As a proportion of total revenue, subsidies have declined overall, falling to 6 percent from 11 percent. Subsidies are now targeted at agricultural customers only (the agricultural sector constitutes 26 percent of the consumer mix).

In Gujarat, the utilities have been profitable since unbundling (figures 5.16 and 5.17). Gujarat has very low debtor days (when compared with other states) and this metric continues to decline. The state has also managed power purchase costs very well, having entered into sufficient long-term contracts that it is a net seller of electricity. However, for all utilities, the commercial and industrial customer segments continue to pay electricity rates higher than average cost, and agriculture continues to receive large cross-subsidies. The distortionary effects of these policies raise the price of electricity for growth-producing sectors of the economy and artificially constrain household consumption by raising the price of electricity above average cost. It is also interesting to note that despite having a considerable share of agriculture in the energy consumption mix, the state has capped its subsidy to the sector at about Rs 11 billion per year.

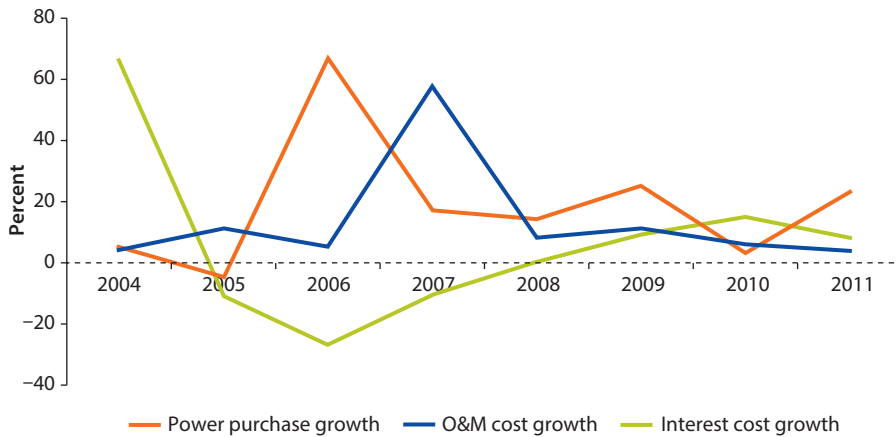
Further analysis of the power sector in West Bengal shows that no additions to state-owned capacity are expected in the near future. Assuming no efficiency improvements are made in future years, the state will need a one-time tariff hike of only 11 percent in FY 2016/17 to close the financial gap. This favorable

Figure 5.16 Gujarat: Accumulated Profits and Losses, by Segment



Source: India Power Sector Review Database.

Figure 5.17 Gujarat: Growth in Cost Components, 2004–11



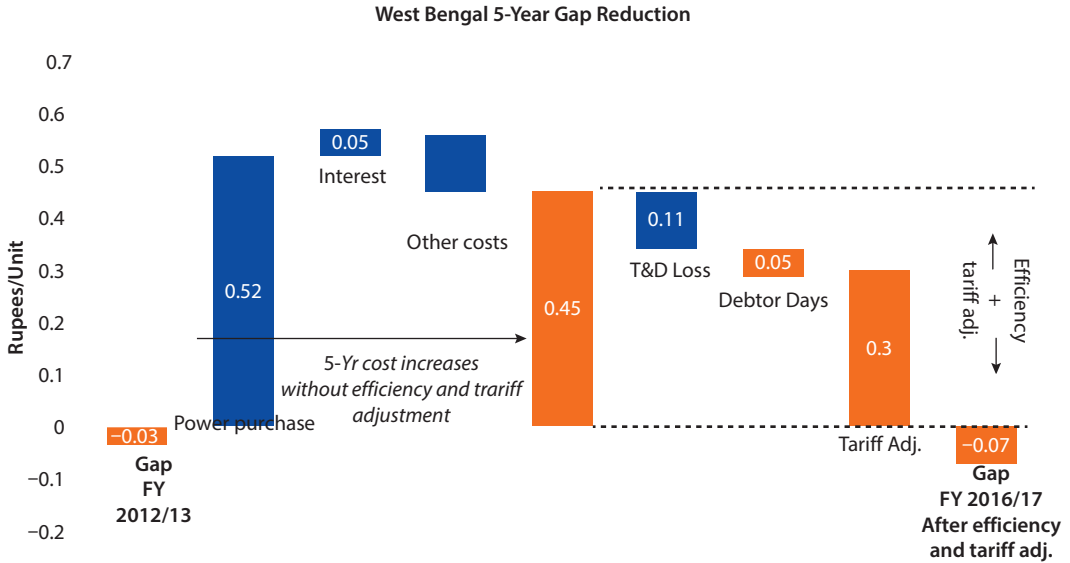
Source: India Power Sector Review Database.
 Note: O&M = operating and maintenance.

financial position can be attributed to the good performance of the utility in the past. The state is expected to make profits without any subsidy support from the government. To further increase profits in the future, the state needs to make minor efficiency improvements and back them up with small tariff adjustments every year. Improvement in rehabilitation and maintenance of older plants to improve generation efficiency along with continued regular tariff increases and improvement in debtor days should sustain the efficient performance of the sector. Figure 5.18 shows the efficiency gain projections for the state and their impact on the financial gap.

For Gujarat, the distribution companies need to transfer the tariff burden to other consumers, given that the state government has placed a cap on subsidies to agricultural consumption. Also, the National Tariff Policy of 2008a recommends a reduction in cross-subsidies to ± 20 percent of the cost of supply by 2012. Analysis suggests that, assuming no efficiency improvements in future years, the state will need a one-time tariff hike of 19 percent in FY 2016/17 to close the existing financial gap. The good performance of the utility historically is responsible for its current financial position. Figure 5.19 shows that with a T&D loss reduction of 18.9 percent by 2016/17 (from 22.7 percent in 2010), a marginal reduction in debtor days of five days per year, and regular tariff increases of only 3 percent per year, the state can achieve efficiency gains.

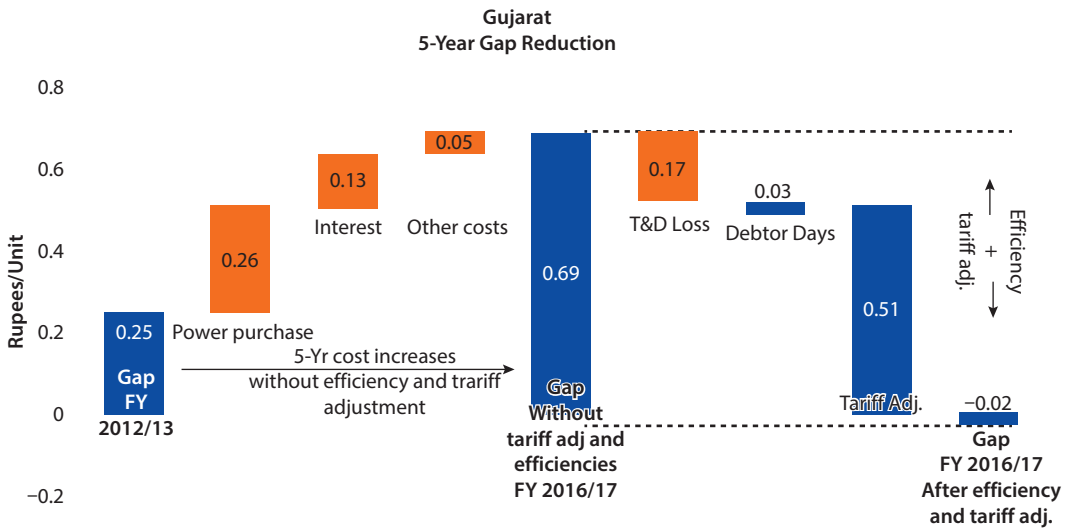
Maharashtra: Despite introducing several demand-side measures, peak and off-peak deficits in Maharashtra have been very high since unbundling in 2005, and the generation company is investing heavily in new generation to meet the expected peak demand (which is estimated to almost double from 15,988 megawatts in 2010 to 29,738 by 2017). Subsequent to unbundling, the sector has eased the subsidy burden on the state. The generation company has created a

Figure 5.18 West Bengal: Impact of Efficiency Improvement on Financial Gap (without Subsidy)



Source: AF-Mercados EMI analysis.
 Note: FY = fiscal year; T&D = transmission and distribution.

Figure 5.19 Gujarat: Impact of Efficiency Improvements on Financial Gap (without Subsidy)



Source: AF-Mercados EMI analysis.
 Note: FY = fiscal year; T&D = transmission and distribution.

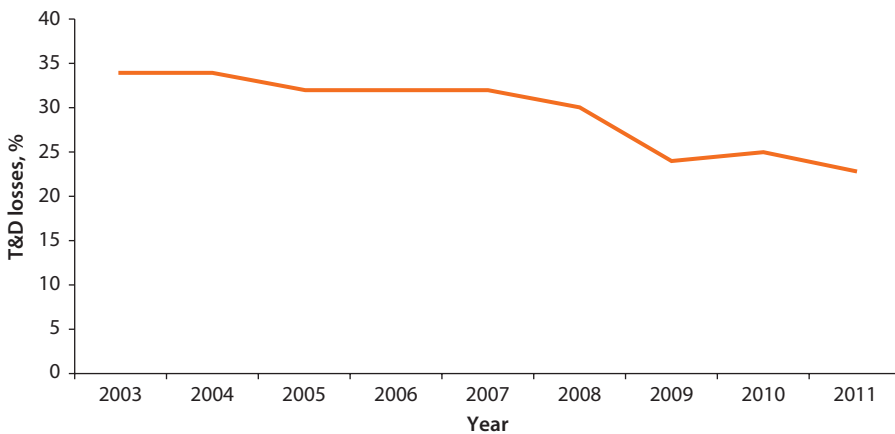
comprehensive policy to encourage private investment in the generation segment. In the transmission segment, the transmission company has maintained a high state of technical performance, in line with international standards. It has maintained transmission system availability of better than 99 percent. It has also

successfully pursued joint ventures for new transmission line investment. The distribution company has pursued several major initiatives to reduce demand.

T&D losses have declined over time (from 34 percent in 2001 to 25 percent in 2010) with improvement in the HT/LT ratio. Even with this improvement, the HT/LT ratio remains lower than the best performing states, indicating scope for improvement in this area. Although agricultural consumption has not changed significantly in the last few years, losses have fallen, indicating that changes in reported agricultural consumption are not used to mask losses. Power purchase costs have remained relatively stable because of relatively low reliance on expensive short-term purchases. Power purchase costs form more than 50 percent of the total costs of the sector but increased to 60 percent in 2010/11. Figure 5.20 shows the declining T&D losses in the state.

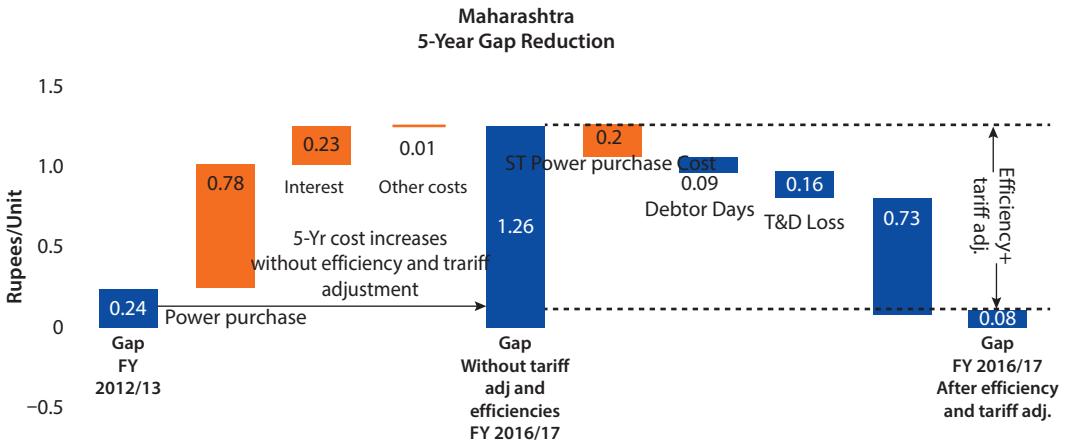
The consumer mix is favorable in Maharashtra, where industrial consumers are major consumers of electricity (45 percent), whereas the share of agricultural consumers is relatively low, at 22 percent. The financial performance of the power sector has been stable, overall. Aggregate revenues have kept pace with costs (as a proportion of total revenue, losses have not been greater than 3 percent in any year). Although the sector as a whole has been cash profitable, the distribution segment has not been able to cover its costs. Since 2008, total debt has increased by 38 percent. Debt has increased the most in the power generation segment, at 58 percent year-on-year. Although the generation segment has taken on the most debt and incurred the highest rate of increase in debt service during the last three years, the distribution segment has the highest interest expense overall. Despite financial restructuring in 2005, at which time the utilities started with a clean slate, payables have gone up significantly in subsequent years, indicating cash stress. Debtor days have been consistently increasing for the generation and distribution segments. The sector still has high aggregate technical and commercial losses (about 35 percent in recent years).

Figure 5.20 Maharashtra: T&D Losses, 2003–11



Source: AF-Mercados EMI analysis.

Figure 5.21 Maharashtra: Impact of Efficiency Improvements on Financial Gap (without subsidy)



Source: AF-Mercados EMI analysis.
 Note: FY = fiscal year; T&D = transmission and distribution.

For Maharashtra, further capacity additions are expected to diminish the free cash available in the system during some of the years in the future. The state can bring down the already-low financial gap and move into profitable territory with efficiency improvements in power purchase costs and tariff increases. Debtor days are also quite high, and the distribution company should try to bring them down. Attaining efficiency gains will entail reducing debtor days by 20 days per year between 2014 and 2017 and reducing short-term power purchases (by Rs 0.50 kilowatt hour/year from 2014 to 2017) (Figure 5.21). A reduction of T&D losses from 25 percent in 2010 to 19.50 percent in 2017 is also required, as are regular tariff adjustments of 4 percent per year between 2014 and 2017.

Group 3: Poor Performers for Whom the Turnaround May Be Easier

Punjab, Jharkhand, and Orissa: The Punjab power sector incurs high power purchase costs that negatively affect its financial performance. Generation capacity in the state has remained stagnant in since 2004 (a reported 4,532 megawatts in 2004 and 5,139 megawatts in 2010), leading the state to resort to short-term power purchases from the market. As of 2010/11, power purchase costs constituted close to 40 percent of the total costs of the state electricity board. However, the state has commissioned three thermal power plants with a capacity of about 4,000 megawatts and two hydroelectric power plants with capacity of about 250 megawatts. These additions are expected to ease the power shortfall faced by the state and reduce the financial burden.

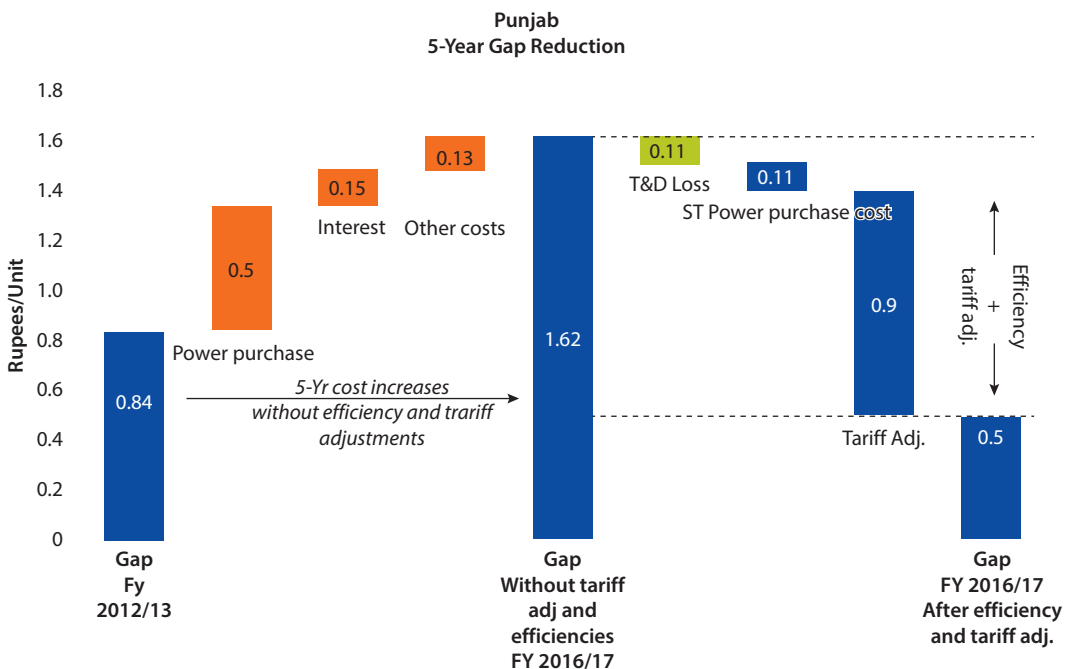
The T&D losses have reduced to around 24 percent in 2010 primarily due to the investments in HT lines. Analysis also shows that short-term power purchase

cost reductions, reduction in T&D losses and tariff increases are expected to have a significant impact on the financial gap (without subsidy) (figure 5.22).

Jharkhand has a poorly performing power sector despite being a resource-rich state (with about 33 percent of India’s coal reserves) and a large share of industrial consumers (71 percent). Installed capacity in the state has remained stagnant since 2004 (1,630 megawatts in 2004 and 1,680 megawatts in 2010). Operational inefficiency primarily accounts for the poor performance of the sector. Generation efficiency has been poor because of a suboptimal station heat rate, plant load factor, and auxiliary consumption. Transmission and distribution losses have been quite high. The sector’s performance on debtor days (131 days in 2010) and creditor days (363 in 2010) is extremely poor. Given the huge industrial consumer base of the state, improving operational efficiency seems to be the quickest way for the sector become viable. Analysis shows that by reducing debtor days by 25 days annually, the cash gap would narrow by approximately 11 percent. Without any efficiency improvements or tariff adjustments in the next few years, the sector’s financial gap will be so high by FY 2016/17 that an estimated one-time tariff increase of close to 150 percent would be needed to close the gap.

In Orissa, industrial consumers are the major consumers of electricity, with a consumption share of 54 percent. Installed capacity in the state is mainly reliant on hydro (51 percent) followed by coal (46 percent). Very little new installed capacity

Figure 5.22 Punjab: Impact of Efficiency Improvements on Financial Gap (without subsidy)



Source: AF-Mercados EMI analysis.

Note: FY = fiscal year; T&D = transmission and distribution.

has come on line since 2004 (2,301 megawatts in 2004 and 2,546 megawatts in 2010). However, the state has had low levels of energy and peak deficits, although T&D losses are high (37 percent in 2009/10) despite a high HT/LT ratio. Domestic and commercial tariffs have declined in the past years (although only marginally). Between FY 2005/06 and 2010/11, the generation segment has remained profitable and net profit margins for the transmission and distribution segments were also recorded between (4.4 to 5 percent) suggesting that the financial gap to be closed is very small. Sensitivity analysis shows that at an annual tariff increase of 6 percent throughout the period and a 1 percent reduction in T&D losses on an annual basis can bring down the cumulative financial losses by one-third.

Risks to the Financial Position of the Power Sector in the Future

Various risks can affect the projections discussed in this chapter, as reviewed in this section. These risks can be divided into two types. The first type is systematic risk, that is, risks that have a long-term impact on the entire system. These risks affect investment decisions and can cause the system to become financial unstable. The second type is nonsystemic risk, risks that have a short-term impact on the financial health of utilities.

Systemic Risks

Generation

Coal shortages. Coal linkages awarded to projects under construction have very low reserves compared with estimates, increasing the risk of inadequate supplies and making the sector more dependent on imported coal. However, some of the older plants are not designed to operate using imported coal as fuel. Hence, supply constraints can be a major risk factor in the future. Even if the plants begin to depend increasingly on imported coal, the increased cost may not always be passed through in tariffs determined through competitive bidding.

Solvency of buyers. The cash positions of the generation companies can be severely affected by nonpayment by their biggest buyers (distribution companies). This problem could erode the financial capability of the generating companies to expand and upgrade services, leading to deficits in generation capacity.

Land acquisition and environmental clearances. Power plants and utilities face major constraints and delays due the availability of land and the requirement to obtain environmental and other clearances for projects. If these procedures are not expedited, the credibility of both the industry and the government will be harmed, eventually affecting the flow of investments to the sector.

Transmission

Land acquisition and environmental clearances. As on the generation side, transmission utilities also face constraints and delays from the availability of land and requirements for environmental and other clearances for installing transmission lines.

Distribution

Power purchase costs. Any increase in power purchase costs from either increases in fuel costs or overreliance on short-term power procurement can negatively affect the future financial positions of the distribution companies. Power purchase costs account for close to 80 percent of the total costs of distribution companies. High power procurement costs can lead to states resorting to loans, which in turn entail higher interest expenses.

Debtor days receivable. Significant increases in debtor days can cause receivables to inflate, resulting in future cash flow problems.

Regulatory risks. Nonapproval of expenses by state regulators because utilities failed to achieve efficiency targets can lead to wider financial gaps in the future. Adequate tariff revisions on a regular basis can mitigate these market risks. Private distribution companies are likely to face risks pertaining to regulatory uncertainties and intervention by state governments, autonomy of state load dispatch centers, and competition caused by the provision of multiple licenses and open access.

Nonsystemic Risks

Pay commission hikes. The Sixth Pay Commission had a strong impact on utility finances. The cost burden for the utilities was large and sudden, bringing the utilities to a state of paralysis that affected their operations. Future pay commission revisions could have a similar impact on utility finances.

Election impacts. In the past, election years have caused power purchase costs to rise significantly, one of the major reasons for the deterioration of the financial health of distribution companies in those years. As evidenced by past behavior, during election campaigns wholesale power market rates are likely to shoot up because of increased demand. This is the nature of market dynamics, and as long as India follows the competitive market model, such cost increases need to be explicitly accounted for in the budget.

Notes

1. Gap as a proportion of average cost = (average cost per unit-average revenue realized per unit)/average cost per unit.
2. The terms *T&D losses* and *distribution losses* are used interchangeably.
3. Tamil Nadu's substantial dependence on power purchases is caused by the state's reliance on wind power (almost 42 percent), which is also costlier. Moreover, wind energy is only an intermittent source of electricity and backup supplies from other sources are essential.
4. The recent integrated rating of distribution utilities published by the Ministry of Power also rates the four Gujarat distribution companies in the top four, while the West Bengal distribution company holds the fifth position.

A Framework for Monitoring the Performance of the Power Sector

This chapter integrates the efficiency of the power sector value chain into a state performance index that examines various drivers of cost and revenue, their correlation with each other, and their correlation with the financial performance of the utilities. A number of quantitative and qualitative factors were used to measure the performance of various states. These factors are combined into a score that is then used to rank and identify the key drivers of credit quality of the state electricity utilities. This performance index succinctly summarizes the credit quality of the state electricity utilities and allows a more nuanced understanding of the sensitivity of each of these drivers and their effects on state finances.

The State Performance Index

The state performance index is created using the analytic hierarchy process (AHP) method. Selected experts from financial institutions and banks were asked through a survey to make a pair-wise comparison of various factors for the purposes of lending to the power sector. There are 12 major lenders to power sector utilities in India, including private banks, government banks, and other financial institutions such as the Rural Electrification Corporation and Power Finance Corporation. Five major lenders were selected, accounting for 42 percent of major lenders to the power sector.

The eleven factors used for this analysis comprise the following (table 6.1):

- Gap after subsidy $(AC-AR)/AC$
- Subsidy/total cost
- Subsidy received/subsidy booked
- Transmission and distribution (T&D) loss
- Collection efficiency
- Debtor days
- Creditor days

Table 6.1 Proposed Performance Parameters in AHP

State	Gap after subsidy (AC-AR)/AC	Subsidy/AC (%)	Subsidy received/ booked (%)	T&D Loss (%)	Collection Efficiency(%)	Debtor Days	Creditor Days	Future Gap (2017)/ Current ACS	(Accumulated Losses + Subsidy receivable)/ Current Turnover	Energy Deficit (%)	Power Purchase Cost/unit (Rs/Unit)
AndhraPradesh	0.00	27.75 ^b	48 ^b	18 ^a	99 ^a	50	41	0.06	-0.16	-6.6	2.69
Assam	0.17	0.00		33	96	108	52	0.31	-0.38	-8.5	3.01
Bihar	0.35 ^b	19.58	100	44 ^b	94	653 ^b	96	0.25	-1.62 ^b	-14.4	2.81
Chattisgarh	0.07	0.00	0	19	95	65	0 ^a		-0.06	-2.5	1.93 ^a
Delhi	-0.05	0.00	0	22	95	239	11 ^a	0.03	0.03 ^a	-0.8 ^a	3.99
Gujarat	-0.01 ^a	6.30	100	23	99 ^a	43 ^a	0 ^a	-0.18	0.01	-4.5	2.92
Haryana	0.11	24.18	100	31	97	69	61	0.39	-0.46	-4.2	3.46
Himachal Pradesh	0.05 ^a	0.00	100	21	95	48	139	-0.61 ^a	-0.01	-3.9	4.26 ^b
Jharkhand	0.19	13.82	100	22	137	131	363 ^b	0.70 ^b	-2.29 ^b	-7.8	2.29
Karnataka	0.01	14.05	90	19	98	179	162	0.10	0.03	-7.7	2.71
Kerala	-0.04	0.00	0	20	98	37 ^a	78	0.28	0.23 ^a	-2.4	3.81
Madhya Pradesh	0.24	8.49	100	38 ^b	86	205	120	0.13	-0.95	-19.0 ^b	2.56
Maharashtra	0.03	1.35	100	25	97	159	63	-0.02	-0.08	-18.7	2.79
Orissa	0.04	0.00	0	37	96	137	151	0.17	-0.78	-0.9 ^a	2.21 ^a
Punjab	0.09	23.53	100	23	99 ^a	74	13	-0.45 ^a	-0.80	-13.8	4.18 ^b
Rajasthan	0.00	54.45 ^b	7 ^b	30	95	43 ^a	30	0.30	-0.50	-2.4	3.92
Tamil Nadu	0.34 ^b	5.86	100	18 ^a	94	95	39	1.38 ^b	-1.44	-6.2	3.91
Uttar Pradesh	0.26	9.00	100	33	83 ^b	323 ^b	551 ^b	0.20	-1.34	-21.6 ^b	2.82
Uttarakhand	0.20	0.00	100	25	88	183	315	0.05	-0.78	-6.5	2.49
West Bengal	-0.01 ^a	0.00	100	18 ^a	94	85	55	-0.17	-0.03	-2.8	2.77

Source: AF-Mercados EMI analysis.

Note: T&D = Transmission and distribution.

a. Best states in each parameter.

b. Worst states in each parameter.

- $(\text{Accumulated losses} + \text{Subsidy}) / \text{Current Turnover}$
- $\text{Future gap (2017) (based on business as usual)} / \text{current AC}$
- Energy deficit
- Power purchase cost/unit

The survey started with a larger set of variables. However, these eleven variables, all of which are quantitative, were found to be representative of other aspects captured by other variables. The outcome of the AHP methodology is based on the perceptions of experts. See box 6.1 for more details on the process used in this instance.

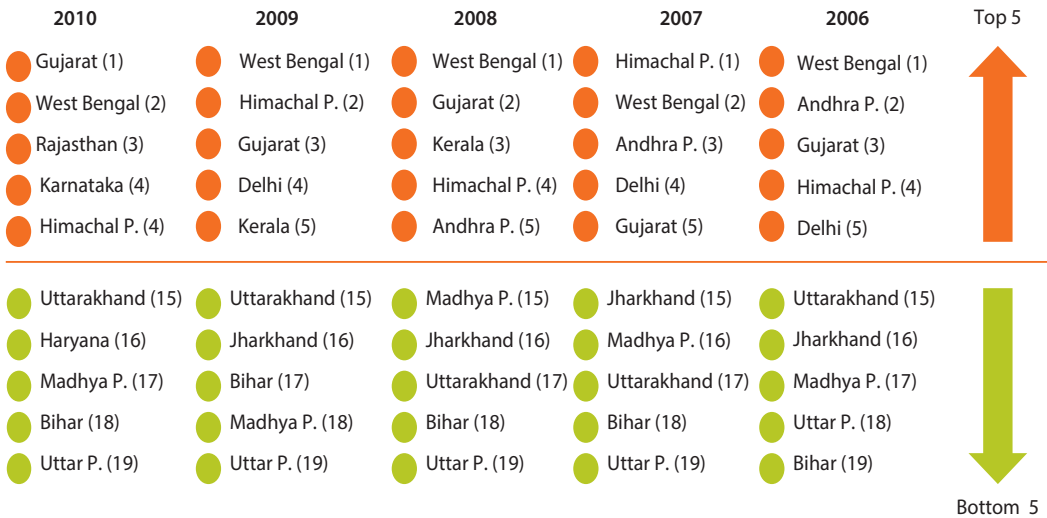
Box 6.1 Method for Construction of Performance Index Using AHP Analysis

To construct the index, each of the eleven variables was assigned a score on a scale of 0–5. A score of 5 indicated that the state was among the worst performers on that particular parameter. Weighted sums of these scores were made for each state to generate the index; the weights were the same across states. The weights for the criteria were based on expert opinion, derived from the AHP method. The index was constructed on the basis of the share of a state's weighted score out of the maximum of all such scores. The states were then ranked with respect to their index points. The state with the highest score was the worst performer.

To capture the year-by-year trend in performance, the analysis was carried out for a five-year period, 2005/06 through 2009/10. The indexes for all states were based on the maximum score in 2009/10. Standard AHP is implemented in two stages: First, weights of the various criteria are determined based on a survey of stakeholders. Second, the weights are applied to the criterion in the various states. In the present study, a survey was conducted only for the first stage. A survey for the second stage was not required because the criteria are quantitative. Therefore, the results for each state could directly be obtained by applying the weights to the quantitative data. For example, for the criteria T&D losses and accumulated losses, the states were compared directly on the basis of their reported loss figures. Inclusion of qualitative variables would have increased the time required for the survey. Finally, the methodology presented is illustrative and could be replicated with a larger set of variables for a larger sample.

Gujarat is at top of the list with an index score of 0.73 (figure 6.1). Gujarat, West Bengal, and Himachal Pradesh occupied the top spots during the five-year period. West Bengal and Gujarat performed efficiently during the period of the analysis. Even though Gujarat performs poorly on certain parameters, such as its fixed asset turnover ratio, this factor may be of the result of high investment levels in preparation for future network expansion. There is movement among the top scorers—Andhra Pradesh was in the top-five list until 2008 but fell behind in the last two years of the period. Kerala has reported steady improvement during the five-year period in debtor and creditor days as well as

Figure 6.1 Performance Index for States, 2006–10



Source: AF-Mercados EMI analysis.

Note: Ranking of states out 29 in paranthesis

considerable improvement in its subsidy-received-to-booked ratio (part of accumulated losses) in 2008. Certain states, such as Maharashtra, show good financial performance because of regular tariff increases but inadequate operational performance. Operational performance in both generation and distribution shows room for improvement. Maharashtra, like Kerala, has also improved over time. Improved collection efficiency enabled Maharashtra to secure a higher rank in 2010 than in the preceding year. Kerala and Karnataka have emerged as reasonable performers on both the technical and commercial parameters. Of the two, Karnataka has worse financial performance (very high debtor days), but it improved in the last two years of the period.

Uttar Pradesh is at the bottom of the list with an index score of 3.73 in 2010. Uttar Pradesh, Bihar, and Madhya Pradesh continued to be the worst performers over the entire five-year period. Bihar and Jharkhand fared very poorly on most efficiency parameters (debtor days, collection efficiency, T&D losses, and so forth). These states would gain tremendously from cash collections to reduce debtor days from their abnormally high levels. In Bihar and Jharkhand, the power stations are either shuttered or operating at abysmal efficiency levels. The financial gap in these states can be reduced significantly by addressing the related issues (either improving or shutting down inefficient plants).

Jharkhand exhibited better performance in 2010, showing progress in collection efficiency and hence in debtor days. Jharkhand also achieved considerable improvement in its cash coverage. Rajasthan had high power purchase costs but showed reasonably good performance as the result of high collection efficiency and low debtor and creditor days. Himachal Pradesh performed relatively better

based on its high collection efficiency and low debtor days. Orissa suffered from high T&D losses and has been consistently incurring financial losses.

Haryana and Punjab exhibited high financial losses. Of the two, Haryana performed much more poorly on both generation and distribution. The problems of Punjab are more related to power purchase costs and tariff revisions. The fall in performance of states such as Tamil Nadu and Andhra Pradesh has been precipitous. Tamil Nadu had an abnormally high debt-to-equity ratio. Both states were operationally in good shape, and their financial distress stems from their failure to increase tariffs.

Two conclusions emerge from this analysis. First, power purchase costs have played a key role in the deteriorating finances of the utilities. Utilities that have planned their purchases better and relied on own generation and contracted purchases have fared better than those that have relied on external purchases. The high tension/low tension (HT/LT) ratio plays an important role in T&D losses and consequently in power purchase costs, which in turn affect the financial gap. Poor network capacity planning (allowing additional connections without adequate network investment) has increased T&D losses. Efficiency improvements and tariff increases would thus have to go hand in hand. In general, the states that have revised tariffs regularly have also improved efficiency—for example, Gujarat, Kerala, and West Bengal. Their nominal tariff increases have been adequate to offset their rising cost profiles. In contrast, the states that have neglected to increase tariffs have been hit the hardest.

Maharashtra is an outlier in the sense that the utility has received reasonable tariff increases but efficiency has not improved commensurately. However, Maharashtra has used the regular cash flows from tariff increases to moderate the effects of emergency purchases. The states that have not revised tariffs have seen declining efficiency, as in Jharkhand, Rajasthan, and Tamil Nadu.

The results from the AHP analysis can be cross-checked against the more rigorous data envelopment analysis to corroborate the findings, as presented in chapter 4. The rankings of states are aligned in these two models, lending further credibility to the use of AHP on a more frequent basis to monitor the commercial viability of the sector.

In 2012, the Ministry of Power formulated an integrated rating methodology to rank the performance of the state power distribution utilities. The objective was to facilitate assessment of performance in an objective and holistic manner. The Ministry of Power has mandated Power Finance Corporation to coordinate the rating exercise, and Power Finance Corporation (PFC) in turn has appointed ICRA and CARE to perform the ratings. The exercise does not cover state power/energy departments and private sector distribution utilities (table 6.2). The results of the AHP analysis and the ICRA/CARE analysis are similar. In the ICRA/ CARE rating, Gujarat utilities lead the performance index, followed by West Bengal, and the distribution ratings in Uttar Pradesh are assigned the lowest ratings.

Table 6.2 Parameters Used in the Ministry of Power Ratings Methodology

	<i>Key issue</i>	<i>Weighting</i>	<i>Number of parameters analyzed</i>	<i>Select parameters</i>
1	Financial performance	63	8	Subsidy received, cost coverage ratio, AT&C losses
2	Regulatory environment	15, -15	8	Issue of regulatory guidelines; issue of tariff guidelines; timely issue of tariff orders
3	Audited accounts	5, -12	2	Availability of audited accounts and audit qualifications
4	Cross-subsidy	0, -2	1	Extent of cross-subsidy
5	Reform measures: unbundling and corporatization	0, -5	1	Status of unbundling and transfer of assets
6	Forward-looking parameters	5, -1	3	Utilization of RAPDRP funds; use of automatic pass-through
7	Incentive/bonus marks	12	12	Consumer metering, RPO compliance

Source: India Ministry of Power.

Note: AT&C = aggregate technical and commercial; RAPDRP = Restructured Accelerated Power Development and Reform Program; RPO = renewable purchase obligation.

A comparison of performance indexes under the AHP/data envelopment analysis (DEA) and ICRA/CARE approach developed by ICRA/CARE reveals the following:

- On financial parameters, all the analyses cover the key parameters.
- Factors such as unbundling and corporatization reflect a bias that utilities that have unbundled are better. This may not be true because the decision to unbundle rests on the economies of scope that may be achieved by unbundling. For example, Kerala, where unbundling has not taken place, is better on both operational and financial criteria than Uttar Pradesh or even Haryana, where unbundling has taken place. A methodology of ranking performance should not have a priori a bias toward a particular market structure, especially when the difference in performance of unbundled versus bundled utilities is empirically ambiguous. The goal of unbundling was to enable the utilities to run on commercial principles and achieve independence in operations, so any parameter that reflects these factors should be included. Financial performance is taken as a proxy for such a parameter.
- Issues of regulation, such as timely issuance of tariff orders, are important. However these issues reflect other operational and financial considerations, such as AT&C losses and profits (losses). In this case there is multicollinearity in consideration (because more than one consideration reflects the same trait). Creation of regulatory assets is an important consideration. This is reflected in more measurable terms as (accumulated losses + subsidy)/current AC in the AHP and DEA analysis. These parameters also reflect the efficiency of the regulatory commission, which is not under the control of state distribution utilities.

- Automatic pass-through of fuel costs should be reflected in the financial data. For the future, the parameter considered, the future gap in 2017 (business as usual)/current AC), considers not only the impact of automatic pass-through of fuel costs but also other forward-looking measures adopted by the state.

To summarize, the AHP analysis based on these 11 parameters can be used to provide a quick assessment of the various power utilities at a point of time. Because all the parameters considered under the AHP analysis capture the critical issues, this analysis can also be used to monitor the ongoing performance of the various utilities.

Suggestions on a Way Forward

The electricity sector in India has been lagging. Despite dramatic expansion in installed capacity, supply has never been able to match demand. Economic growth has only placed increased demands on the utilities, and they have struggled to cope. After more than a decade of attempts to attract private capital, the sector was opened up to competition through market reforms of unprecedented magnitude. The reforms that began in the 1990s culminated in the landmark Electricity Act, 2003. The process has been taken forward through a number of subsidiary policies and delegated legislation. The Central Electricity Regulatory Commission (CERC) has played a critical role in the process, achieving its mandate and often going beyond narrow interpretations of legal provisions. As a consequence, India has a large privately funded project development portfolio, vibrant power trading, and a renewable energy trading market at the national level.

The picture at the state level is radically different. The power sectors in many states are reeling from burgeoning accumulated losses and an unsustainable debt profile that imposes a substantial burden on banks, other financial institutions, and state budgets. A set of recommendations based on the diagnostics in this report is presented for each of the segments in the sector value chain.

Generation: The generation sector in general has responded to market signals. Although several states have planned sufficient capacity increases, there is serious concern about the escalating power procurement prices faced by the distribution utilities. In part, the power shortage crisis is a result of constraints outside the core power sector, particularly in fuel availability (of coal, gas, and also nuclear) and land acquisition. Protracted delays and difficulties with these issues are having an exponential impact on the availability and the cost of purchased power. Simultaneously, a majority of utilities have not responded in a timely manner to the need to augment power supplies using new sources, resulting in serious material adverse impacts on utility and state finances. In view of these problems, it is essential that utilities take urgent corrective measures.

Creation of a more competitive bidding process and more focused procurement planning and augmentation of fuel supplies are all necessary. Deficit states urgently need to contract for adequate power. Overreliance on spot markets can

result in very high exposure. A better procurement practice on the part of the utilities is essential for identifying shortages and surpluses and optimizing their procurement portfolios. Thus, better forecasting capabilities are also essential. Finally, the government of India must take steps to augment fuel supplies for power projects.

Fuel is a key constraint for new projects. "Untied projects" that are not identified with a fuel source have the last priority in fuel allocation. This practice needs to be revisited, and a level playing field must be created. Fuel supplies need to be augmented significantly. For coal, alternative mining and supply mechanisms should be created. The Ultra Mega Power Projects process could be replicated in the coal sector to supply least-cost coal to power projects.

As discussed earlier in chapter 4, many state-owned plants are running at low levels of efficiency because of poor operations and maintenance, mainly due to the shortage of supply in the system. These plants need to be rehabilitated, or closed if rehabilitation is not a commercially viable option.

Transmission: The transmission sector should be improved to meet load growth and system strengthening needs. The state-level transmission networks are weak. Although the investment flows in the transmission systems have improved since the commencement of the reform and restructuring process, significant measures are required to create the desired efficiencies in the transmission system. Substantial investments are required for transmission evacuation projects and for system strengthening. Unbundling is critical to providing a focus on transmission, and it is important that the states that have yet to comply with the mandate of the Electricity Act, 2003, on the unbundling of the transmission system be required to do so.

Attention needs to be given to system planning, transmission pricing, and the strengthening of renewable energy evacuation capabilities. Improvements are required in system planning. At present, system planning is reactive, and, barring exceptions, there is no emphasis in the states on forward planning. The planning process (and the underlying forecasting and other related processes) needs to be strengthened. In view of the large investment requirements, as well as the need for greater efficiency in project execution and in pricing, it is essential to institutionalize public-private partnerships in transmission. Although public-private partnerships have been the policy objective, protracted delays in implementation have occurred. System operations should be made completely autonomous, in line with the mandate of the Electricity Act, 2003. Failure to complete unbundling will make it difficult to ensure open access and competition in power markets. It is essential that the government of India and the states implement the Pradhan Committee recommendations.¹ It is also essential to implement policy recommendations on the Bulk Power Transmission Agreement and transmission pricing based on distance and direction. The CERC has initiated the process of implementation, and states should evaluate similar measures to ensure efficient pricing and use of the transmission system. Renewable energy sources must be adequately integrated into the transmission network, and necessary evacuation arrangements should be created and priced efficiently. Apart from the benefits of

clean energy sources, the present cost of renewable energy (especially wind, small hydro, and biomass) is substantially lower than the prices currently paid by the utilities for purchases from the competitive power markets.

Distribution: The distribution segment continues to be weakest part of the Indian power sector. Significant information and capability deficiencies continue to affect distribution operations. States that have taken proactive measures on measurability, accountability, and governance also have significantly better financial performance. Distribution reforms need to be scaled up substantially, with adequate monitoring of performance at each level in the distribution company to bring about these required improvements:

- **Power planning:** Power purchases account for more than 60 percent of total distribution costs, and therefore it is crucial that utilities should carry out comprehensive exercises to project short-, medium-, and long-term demand, including seasonal fluctuations in demand. Power procured on a short-term basis during energy-deficit situations will always be costlier and will have adverse impacts on state finances. The aim should therefore be to minimize short-term purchases of power.
- **Demand assessment and network planning:** The existing networks need to be strengthened to ensure that utilities' power distribution capabilities are efficient and adequate to meet not only the current demand but future demand requirements as well. This requires in-depth demand assessment and network planning. Studies demonstrate that the present levels of technical losses in the networks are unacceptably high in some of the large states, such as Uttar Pradesh and Bihar.
- **Data quality:** Energy data are still not reliable and timely. The majority of the state distribution companies in India are burdened by incomplete metering, defective meters, and manual meter reading. These problems lead to inadequate billing and revenue collection. There is an urgent need to focus on energy auditing and to contain AT&C losses.
- **Skills:** The Restructured Accelerated Power Development and Reforms Programme (R-APDRP) promotes the use of information technology to improve energy auditing, reduce losses, and increase efficiency. The various states are at different stages of implementing R-APDRP, but the R-APDRP initiatives can be successful only if the capacity of the utility staff is improved through recruitment of workers with the appropriate skills and requisite training in information technology.
- **Customer satisfaction:** In India, about 20 percent of the consumers account for around 80 percent of the revenue due to the tariff structure and load profile in most states. To improve their finances, distribution utilities can focus on revenue augmentation and loss reduction in the key urban areas. Distribution utilities need to focus on enhancing customer satisfaction by providing efficient and reliable service. Suitable technology interventions such as providing power-cut information on customer mobiles can be adopted to improve the experience. Well-functioning customer service centers have increased customer satisfaction in many utilities.

- **Rights of consumers:** At present there is very little focus on the rights of the customer. There are documented cases of the utilities cutting off their own customers to profit from short-term power market sales. Supply obligations should be enforced. If power is available, utilities should not be allowed discretion to deny service to customers.
- **New business models:** Enhanced private participation through franchising and other means could be extremely beneficial in bringing about improvements. Initial results from franchising in difficult areas, such as Bhiwandi in Maharashtra, are encouraging. The ambit of such programs could be enlarged to allow economies of scale and scope.

Note

1. See www.powermin.nic.in/whats_new/pdf/Report_of_the_Committee_on_Manpower_Certification_and_incentives.pdf.

APPENDIX A

List of Definitions

<i>Variable</i>	<i>Definition</i>
Accumulated profit/loss	Profit/loss that is carried over to the next fiscal year
AR (excluding subsidy)	Total revenue (excluding subsidy)/input energy
AT&C losses	(Net input energy (Mkwh) – energy realized (Mkwh) × 100 net)/input energy (Mkwh)
Average cost	Total costs/input energy
Average revenue (with/without subsidy)	(Total revenue ± subsidy booked)/input energy
CAGR	(Ending value/beginning value) ^ (1/# of years)
Cash profit	PBT + depreciation
Collection rate	(Net revenue from sale of energy – change in debtors for sale of power × 100) /net revenue from sale of energy
Creditor days	Creditors for sale of power × 365 revenue from sale of power
Debtor days	Debtors for sale of power × 365 revenue from sale of power
EBITDA	Total revenue – (power purchases, fuel, O&M, other, costs capitalized)
Gap (without subsidy)	AC – AR (excluding subsidy)
Gap (with subsidy)	AC – AR
Input energy (Mkwh) distribution companies	Energy purchased (Mkwh) + net generation (Mkwh)
Input energy (Mkwh) SEB/ power department	Energy generated (Mkwh) – auxiliary consumption (Mkwh) + energy purchased (Mkwh)
Input energy (Mkwh) SEB/ power department (transcoms)	Energy purchased (Mkwh) + net generation (Mkwh)
Net generation	Generated units – auxiliary consumption
Net worth	Sum of equity, reserves, accumulated profits
O&M costs	Sum of R&M, A&G, employee cost

table continues next page

<i>Variable</i>	<i>Definition</i>
Operational costs	Sum of power purchase, fuel, O&M Costs, depreciation
Operational costs	Power purchase costs + operation and maintenance cost + costs capitalized and other debits + depreciation + other costs
Operations and maintenance cost	R&M + A&G + employee costs
PAT	PBT – provision for taxation
PAT w/o subsidy	PAT – subsidy booked
Profit before tax	Total revenue – total costs
Subsidy booked	Subsidy booked in utility accounts as arrears promised by the state government
Subsidy received	Subsidy that is actually paid by the government to the utility
T&D loss	(1 – total energy sold)/input energy
Total capital employed	Sum of total loans, net worth, consumer payments, grants toward capital assets
Total costs	Operational cost + interest
Total loans (debt)	Sum of loans from financial institutions, states, and other sources
Total revenue	Revenue from sale of power + grants and subsidies booked + revenue from trading + other revenue

Source: World Bank.

Note: AR = average revenue; AT&C loss = aggregate technical and commercial loss; CAGR = compounded annual growth rate; MkwH = million kilowatt hour; O&M = operating and maintenance; PAT = profit after tax; PBT = profit after tax; R&M = renovation and modernization; T&D = transmission and distribution.

APPENDIX B

The Abraham Committee Report

The Abraham Committee was an independent taskforce set up to (1) monitor and access the implementation of the Accelerated Power Development and Reform Programme initiative to ensure transparency and accountability; and (2) provide recommendations for improvements to ensure success of the program. Based on the committee's findings and recommendations, the Restructured Accelerated Power Development and Reform Programme was launched in the 11th Plan.

Key Findings:

- Despite the Ministry of Power's commendable efforts at the national level in terms of policies and guidelines—for example, notification of the Electricity Act, national electricity policy, and tariff policy—many states had yet to adopt a reform path or implement sanctioned Restructured Accelerated Power Development and Reform Program (RADRP) projects.
- States that adopted reforms performed better than states that did not.
- Utility-level performance monitoring needs to improve.
- Financial performance has further deteriorated. Rampant theft keeps aggregate technical and commercial loss (AT&C) losses high, but states have not been able to combat theft effectively.
- Some 96 percent of feeders have been metered, but significant benefits will not be apparent until energy auditing is widely adopted.
- Unmetered agriculture consumers not only hurt the bottom line, but negate incentives for improved financial and technical performance from utilities. Inadequate subsidies do not cover the provision of free/cheap power.
- Delays of sanctioned projects could be avoided through better planning using technology to improve project management and monitoring.

Key Recommendations

- RAPDRP should be extended beyond the 10th Plan, and program assistance should be extended to private sector.
- Introduce more stringent criteria for receiving assistance to force states to reform:
 - Restructuring/unbundling
 - Functioning state electricity regulatory commission (SERC)
 - Establish antitheft special courts and police
 - States have to commit to achieve various reform targets such as a financial restructuring roadmap, multiyear tariff, energy audit/accounting, 100 percent metering up to 100 kilovolts feeders, and 100 percent metering (including agriculture) for RADPR areas.
- Establish an annual target for AT&C reduction for utilities. Each distribution company may be considered for calculation of incentives against cash loss reduction.
- Give employees incentives for performance improvement: a 5 percent provision for training, hiring consultants, undertaking studies/project evaluation, and other achievements.
- Utilities, advisors/consultants, and the Ministry of Power should bear responsibility for monitoring timely/proper implementation.
- Under the investment component, the grant may be increased to 50 percent of project cost for general category states.
- Realistic detailed project report (DPRs) should be made in consultation with the utilities that contain a quality plan and provisions for price variations during execution.

Bailout Package of 2012

In second half of 2011, the Finance Ministry advised public sector banks not to increase their exposure to power utilities, including distribution companies. For most banks, these sectoral caps have been reached especially with lending in generation, and the prospect of bad debts has led to automatic aversion to fresh lending. Most of the banks refused to give fresh loans to the power sector. This has led to flurry of tariff increases during the last two years and the second bail-out of the power sector in just over a decade.

Currently, India is planning to implement a financial rescue to revive the power sector. In September, the Cabinet Committee on Economic Affairs (CCEA) approved the scheme, which will be available to all loss-making distribution companies that wish to participate. Distribution companies must fulfill mandatory conditions to avail the package, which will remain open for enrollment through December 31, 2012. The mandatory enrollment conditions have not yet been announced.

The financial restructuring will bring immediate relief to cash-strapped distribution companies. The key terms of the bailout call for 50 percent of short-term liabilities (up to March 31, 2012) to be taken over by state governments. Currently, the outstanding short-term liabilities are estimated at Rs 1.9 trillion (\$40.4 billion). Issuance of the bonds will occur in 2013, and in 2014 states will begin to service the debt. The proposal calls for the other 50 percent of short-term liabilities to be rescheduled, and for lenders to provide a moratorium of three years on principal payments. The bailout also calls for the central government to provide capital grants (equal to up to half of the debt taken over by state government) for utilities that achieve aggregate technical and commercial loss (AT&C) loss reductions above the targets set out in Restructured Accelerated Power Development and Reform Program (RAPDRP). Banks with high exposure to poorly performing utilities are among the biggest beneficiaries of the bailout, since a large proportion their loans would arguably have turned bad otherwise.

The bailout is expected to be accompanied by a monitoring mechanism to ensure that states improve the operational performance of distribution companies. The limited ability of stakeholders to enforce compliance with performance measures is a key risk. Success of the program depends greatly on the ability of states to follow through on the required reforms, especially annual tariff revisions, pass-through of fuel and power purchase cost adjustments on a quarterly basis, and reduction in transmission and distribution losses. For their part, governments must make timely disbursements of subsidy payments where required.

The debt restructuring will also create more space for lending for asset creation in the power sector. Conversion of the short-term loans to state government-issued bonds would free up an estimated Rs 950 billion (\$20 billion), which could support investment in new generation and transmission projects as well as upgrading of distribution systems. This is good news, since India is projected to require \$66 billion in investment over the next five years. Banks will also see their exposure to the sector reduced by half, which would greatly increase their liquidity and net worth positions.

The Appellate Tribunal for Electricity Judgment of 2011

The Ministry of Power through its secretary sent a letter to the chairperson of the Appellate Tribunal dated January 21, 2011, complaining that most of the state distribution utilities have failed to file annual tariff revision petitions in time and that as a result tariff revision in a number of states has not taken place for several years. State commissions constituted all over India have also failed to make periodical tariff revisions on their own initiative, resulting in the poor financial health of the state distribution utilities. The Power Ministry therefore requested the tribunal to take appropriate action by issuing necessary directions to all the state commissions to revise the tariff periodically, in the interest of improving the financial health and long-term viability of the electricity sector in general and distribution utilities in particular.

The full bench of the tribunal directed state commissions that:

- Every state commission must ensure that annual performance review, true-up of past expenses, and annual revenue requirement and tariff determination be conducted on a year-to-year basis according to the time schedule specified in the regulations.
- Every state commission should attempt to ensure that the tariff for the financial year is decided before April 1 of the tariff year. For example, the average revenue realized (ARR) and tariff for the financial year 2011/12 should be decided before April 1, 2011. The state commission could consider making the tariff applicable only till the end of the financial year so that the licensees follow the time schedule for filing of the application for determination of the ARR/tariff.
- In the event of delay in filing the ARR, truing-up and annual performance review, one month beyond the scheduled date of submission of the petition, the state commission must initiate proceedings for tariff determination in accordance with Section 64 of the Electricity Act read with Clause 8.1 (7) of the Tariff Policy.

- In determination of the ARR/tariff, the revenue gaps ought to be eliminated and regulatory assets should not be created as a matter of course except where it is justifiable, in accordance with the tariff policy and the regulations. The recovery of regulatory assets should be time bound and within a period not exceeding three years at the most and preferably within control period. The carrying cost of the regulatory assets should be allowed to the utilities in the ARR of the year in which the regulatory assets are created to avoid cash flow problems to the distribution licensee.
- Truing-up should be carried out regularly, and preferably every year. For example, truing-up for FY 2009/10 should be carried out along with the ARR and tariff determination for FY 2011/12.
- Fuel and power purchase costs are a major expense for distribution companies that are uncontrollable. Every state commission must have in place a mechanism for fuel and power purchase cost in terms of Section 62 (4) of the act. The fuel and power purchase cost adjustment should preferably be on monthly basis on the lines of the Central Commission's regulations for the generating companies, but in no case exceeding once a quarter. Any state commission that does not already have such formula/mechanism in place must within six months of the date of this order must put such a formula/mechanism in place.

The tribunal directed all the state commissions to follow these directions scrupulously and send the periodical reports by June 1 of the relevant financial year about the compliance of these directions to the secretary, Forum of Regulators, who in turn will send the status report to the tribunal and also place it on its website.

Advanced Benchmarking Techniques

Internationally, there are two main benchmarking approaches used for setting the efficient level of costs and performance benchmarks. They are top-down or empirical methods: data envelopment analysis (DEA) and stochastic frontier analysis (SFA).

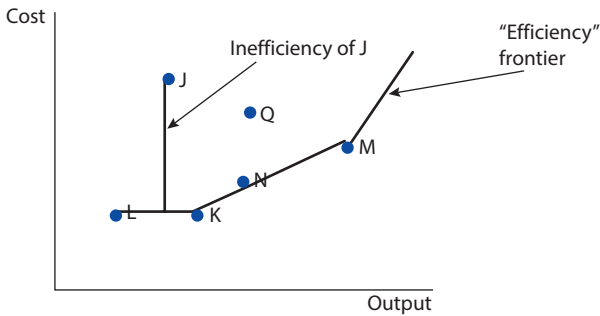
- Data Envelopment Analysis (DEA)
- Stochastic Frontier Analysis (SFA).

Use of Data Envelopment Analysis

Data Envelopment Analysis is a linear programming methodology is used to measure the efficiency of multiple decision making units (DMUs) when the production process presents a structure of multiple inputs and outputs. This method is commonly used for measuring the relative performance of similar utilities where the presence of multiple inputs and outputs and nondiscretionary variables makes comparison difficult.

Figure E.1, a simplified illustration of DEA, demonstrates the cost and output relationships for six utilities. L, K, and M would be interpreted as efficient by DEA users, while the rest would not. J's "inefficiency" is the distance between J and the frontier. The efficiency of the firms is calculated in terms of scores on a scale of 0 to 1 in case of input-oriented models and greater than 1 in the case of output-oriented models, with the frontier firms receiving a score of 1. While the input-oriented models measure the potential of input reduction maintaining the same level of outputs as the best-practice firms, the output-oriented models measure the potential of output augmentation given the same level of input as the best-practice firms.

Figure E.1 Simple Illustration for DEA, Showing Cost and Output Relationship for Six Utilities



In DEA, the efficiency of the firms is computed rather than estimated. DEA identifies an efficient frontier made up of the most efficient firms in the sample and measures the relative efficiency scores of the less efficient firms in relation to these. DEA allows calculation of allocative and technical efficiencies. The latter can also be decomposed into scale and purely technical efficiencies. DEA is one of the most commonly used method by regulatory agencies worldwide

Advantages

- DEA can easily handle multiple outputs and can also examine the effect of environmental (nondiscretionary) variables.
- DEA identifies a set of peer firms (efficient firms with similar input and output mixes) for each inefficient firm
- It does not require the user to explicitly specify a mathematical form for the production or cost function, as is case with Stochastic Frontier Analysis.
- DEA has proven to be useful in uncovering relationships that remain hidden with other methodologies.

Limitations

- DEA results can, however, be sensitive to the inputs and outputs in the model, and DEA analysis requires a reasonable sample size for robust estimates.

APPENDIX F

Assumptions Used for Financial Projections

Table F.1 Components of Financial Projections

<i>Component</i>	<i>Methodology/assumption</i>
<i>Revenue assumptions</i>	
Demand	CEA/tariff order with demand growth taken from 18th EPS.
Deficit	CEA values for 2010/11 and 2011/12. Taken a decreasing 2 percent trend after that year. In cases where deficit is at (or reaches) a very low level, it is assumed to stay constant
T&D Losses	Based on a regression analysis, except where results are not statistically valid. (details noted below)
Tariff	Calculated from tariff order/PFC, whichever is the latest available. Growth of 6 percent year-on-year assumed for all categories other than agriculture in the future
Consumption by consumer category	2009/10 consumption by category taken from PFC. The same consumer mix is assumed for future years
Consumer category Consumption growth	Assumed at the same rate as total consumption.
Grants and subsidies booked	As a percentage of sale of power, based on historical trends
Other revenue	As a percentage of sale of power, based on historical trends
<i>Cost assumptions</i>	
Power purchase cost	APPC forecasts (see below)
Transmission cost	CERC approved rates for each state. Assumed 5 percent increase year-on-year
R&M expense	Regression analysis
A&G expense	Taken as 6 percent
Depreciation	As a percentage of opening net fixed assets, based on historical trends
Interest expense	11.5 percent and 12.5 percent for long-term and short-term loans, respectively.
Capital expenditure	Regression analysis
Employee expense	Weighted average of the 6th Pay Commission pay hike and escalation rates based on CPI/WPI

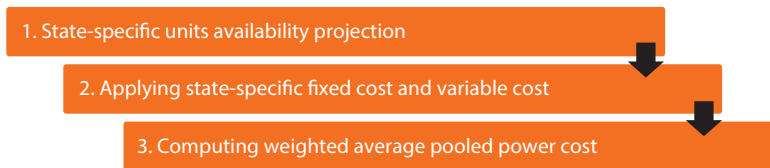
table continues next page

Table F.1 Components of Financial Projections (continued)

<i>Component</i>	<i>Methodology/assumption</i>
Cost capitalized and other debits	Calculated on the percentage of the power purchase cost for the data available, based on historical trends
Other expenses	Calculated on the percentage of the power purchase cost for the data available, based on historical trend
Loan repayments	Any net cash balance remaining used to pay off the outstanding loan
Minimum alternate taxes	Taken as a fixed 18.5 percent
Funding assumptions	
Operational gap funding	The operation losses are funded by the state government loans
Capital expenditure funding	70 percent debt and 30 percent equity
Growth in consumer contribution	Same rate as overall consumption.
Grant toward capital assets	Based on historical increments as a percentage of capital expenditures

Source: World Bank.

Figure F.1 Approach for Forecasting APPC



Average Pooled Power Purchase

“Pooled cost of power purchase” means the weighted average pooled price at which the distribution licensee has purchased the electricity, including cost of self-generation in the previous year from all energy suppliers long-term and short-term, but excluding those based on renewable energy sources.

Approach Applied

Figure F.1 illustrates the approach followed for forecasting the average pooled power cost (APPC) up to 2025.

State-Specific Units Availability Projection

The steps outlined below have been followed for computing state-specific units availability projection.

- There is a fair visibility of the number of projects that are likely to commission by the end of 12th Plan.
- Assessment of expected capacity additions till the end of the 12th Plan has been carried out. Various sources have been used to assess the expected

capacity additions in different years: Central Electricity Authority (CEA) reports, Ministry of Power data, Planning Commission working group reports, and industry consultation. This sheet is regularly updated with information regarding new projects.

- To account for the allocation from central generating stations, allocations for the existing stations has been taken from CEA. For future central sector projects, Ministry of Power data for expected allocations has been used.
- Additional merchant power plants have been accounted for appropriately to capture the amount of power that is expected to go the home state (the state in which the plant is supposed to be located) and the power that has been designated for some other state. The balance of the power produced is currently assumed to go to the merchant pool. For example, Adani's Mundra power project, which is being constructed in Gujarat, has 1,424 megawatts designated for delivery to Haryana. This 1,424 megawatts has been taken into account when Haryana's future generation is being calculated.
- Keeping in mind the capacity addition targets achieved in previous plans, probabilities and slippages have been applied to the annual capacity addition based on the following parameters:
 - Type of power plant (domestic coal, imported coal, gas, hydro, nuclear, and so on).
 - Current level of maturity of the power plant/stage of development.
 - Source of confirmation of the expected year of commissioning (CEA, others). Plants confirmed by CEA have been assigned higher probabilities.
 - The plan in which the plant is expected to be operational (the 11th Plan or 12th Plan).

These parameters have been applied to an aggregated annual capacity from state and private plants. Future central plants have been listed by project and slippages have been assigned.

- To phase out the capacity additions within a year, the following methodology has been used:
 - Future hydro capacity (state and private projects). 50 percent of the capacity is to come up in July of the expected year of commissioning and full capacity to be added by February of the same financial year.
 - Future thermal capacity including gas projects. 50 percent of the capacity is to come up by the middle of the year of commissioning and full capacity to be added in April of the next financial year.
 - Net generation is computed from different plants after accounting for auxiliary consumption and transmission losses.
 - To forecast monthly generation, different methods have been adopted for thermal, nuclear, and hydro plants.
 - For the existing thermal (coal-based) plants, the existing generation profile is used and the same monthly profile is assumed until 2016/17. For

upcoming thermal projects, a higher annual plant load factor (90 percent) is assumed and the monthly profile is derived from the profile of existing projects. For both existing and upcoming gas-based and nuclear projects, an annual plant load factor of 85 percent is assumed. This takes into account higher gas availability from the Krishna-Godavari Basin and a higher availability of nuclear fuel after the signing of nuclear fuel agreements. A flat monthly availability profile is taken for both gas and nuclear power projects. For hydro projects, analysis of regional profiles of hydro plants in the past has been applied to various new hydro projects coming on line in different regions.

- For computing state-specific unit availability, renewable energy that will be available in the state in the future is taken into account to assess the state's overall energy balance. This computation will use the units computed in the Rural Electrification Corporation (REC) liquidity exercise. The estimates of renewable energy supply available in the future in the states that will be used in APPC computation will be based on the Ministry of New and Renewable Energy (MNRE) estimated potential of various renewable energy technologies.
- Assessment of technology-specific capacity additions beyond the 12th Plan has been assumed on a regional level and then further broken down into state-specific capacity allocations based on the share of the state at the regional level.

Applying State-Specific Fixed Costs and Variable Costs

The total cost component has been divided into the fixed cost and variable cost, taking into account the type of fuel.¹

Fixed Cost

The following steps have been undertaken for projecting state-specific and fuel-specific fixed costs.

Base year fixed cost

- We assume fiscal year 2010/11 as the base year.
- We divide the base year supply into public and private components.
- Since the capital cost of projects will differ based on the age of the plant, which will have a direct impact on the fixed cost, the existing projects (up to 2010/11) have been categorized into the following groups based on their age (from their date of commissioning):
 - Category 1—Greater than or equal to 30 years (that is, all plants that were commissioned on or before 1981)
 - Category 2—Between 20 and 30 years (all plants that were commissioned between 1982 and 1991)

- Category 3—Between 10 and 20 years (all plants that have been commissioned between 1992 and 2001)
- Category 4—From 0 to 10 years (all plants that have been commissioned from 2002 onward)
- This categorization has been made separately for public sector and private sector plants.
- For each of these categories, we take the fixed costs from a standard business plan (for a coal, gas, or hydro power project) for a private sector and a public sector financial model.
- For each of these categories, the following aging assumption is used for inputting the fixed costs from the financial model:
 - Category 1—Year 31 onward fixed cost
 - Category 2—Year 26 onward fixed cost
 - Category 3—Year 16 onward fixed cost
 - Category 4—An average commissioning year has been assumed based on the actual commissioning year of all projects that have come on line till 2010/11.
- The capital cost assumptions used compute the fixed costs for different ages of the power projects are provided in table F.2.
- On the basis of this method, we computed the weighted average fixed costs for 2010/11 (by power plant).²

Forecasts

- The base year standard projections are based on historical costs.
- The capital cost for incremental capacity is assumed to be the same as the capital cost assumptions provided in table F.2.
- For developing forecasts for incremental capacity, we first take 25 years' fixed cost per unit figures from a current financial model of a business plan (separately for hydro, coal, and gas)³("standard lifetime projections").
- For computing fixed costs for nuclear power plants, we used the following methodology:

Table F.2 Capital Cost Assumptions

<i>Age/type of power plant</i>	<i>Hydro (Rs Cr./MW)</i>	<i>Coal (Rs Cr./MW)</i>	<i>Gas (Rs Cr./MW)</i>
≥30 years	1	2.5	2.5
20–30 years	2	3	3
10–20 years	5	4	4
≤10 years	6.5	4.5	4.5
After 5 years	8.1	5.6	5.6
After 10 years	10.2	7	7

- Since nuclear power plants have a single-part tariff, to compute the fixed costs we assume that the variable cost of a nuclear power plant equals the lowest variable cost of a thermal power plant in the region.
- This variable cost is subtracted from the single-part tariff of a nuclear power plant to arrive at the fixed cost.
- The fixed cost is assumed to be flat on a year-on-year basis.
- For computing the year-on-year fixed-cost forecasts separately for hydro, coal, and gas power plants, we used the following methodology:
 - **Year 1**
 - For base year plants, we take the fixed costs as exhibited by standard lifetime projections.
 - For incremental capacities, we take the first-year fixed-cost figure from standard lifetime projections.
 - We take a weighted average of these costs to arrive at the average fixed cost for Year 1.
 - **Year 2**
 - For base-year plants, we assume a reduction of fixed cost in the same proportion as exhibited by the standard lifetime projections
 - For incremental capacities that came online in Year 1, we take the second-year fixed-cost figure from standard lifetime projections.
 - For incremental capacities that will come online in Year 2, we take the first-year fixed-cost figure from standard lifetime projections as duly inflated for capital cost escalations (we are assuming a 2 percent escalation of capital costs).
 - We take a weighted average of these costs to arrive at the average fixed cost for Year 2.
- We move forward year-on-year (upto year 25) in this manner.

Variable Cost

The variable costs for the different fuels have been assumed as shown in table F.3:

Table F.3 Variable Cost Assumptions

<i>Fuel</i>	<i>Assumptions</i>
Domestic coal	Existing stations according to 2010/11 tariff orders; for future stations, based on fuel linkages and allocation of the plant, and domestic: imported fuel blending = 70:30
Imported coal	
Gas	Current gas market prices for both LNG and domestic gas; domestic gas: LNG = 80:20
Nuclear	Existing stations according to 2010/11 ARR approved by state regulators

Note: ARR = average revenue realized.

Escalation rates for the different fuels are based on Central Electricity Regulatory Commission (CERC) escalation rates.

Computation of Weighted Average Pooled Power Costs

- Weights are computed, based on the units generated from various fuels, taking total generation as the base for the particular year.
- The short-term market volume has been computed as total demand—long-term supply, and short-term market prices have been computed using Mercados' short-term market price model.

T&D Loss Projection Methodology

Regression analysis has been used to project the Transmission and distribution (T&D) loss trajectory for the distribution utilities in India. The methodology used is briefly described below:

- **Step 1:** Elasticity of each consumption category and losses with respect to power purchases using regression analysis are essentially computed for each state. How do the losses change incrementally per 1 percent increase in power purchases?
- **Step 2:** Incremental power purchases are computed based on growth by fuel category, and then incremental losses are computed based on percentage obtained in step 1.
- **Step 3:** Incremental losses are added to base losses to obtain the total losses and computed as a percentage of power purchases. This provides the T&D loss trajectory for each state.

Table F.4 reflects base cases derived from past performance. These are not recommended levels, but serve only as a baseline for projections. Additional sensitivity analysis has been used to identify the impact of varying levels of cost reduction on utility finances and cash gap.

Table F.4 Projected T&D Losses, 2009/10 to 2016/17

State	T&D loss trajectory (%)							
	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Andhra Pradesh	20.0	19.5	18.6	18.0	17.6	16.0	15.7	15.3
Tamil Nadu	18.0	17.6	17.5	17.4	17.0	16.3	16.0	15.7
Karnataka	18.8	18.2	18.0	17.9	17.8	17.7	17.6	17.5
Kerala	17.7	16.1	15.6	15.3	15.1	14.8	14.6	14.3
Maharashtra	25.0	23.5	23.0	22.2	21.5	20.5	20.1	19.6

table continues next page

Table F.4 Projected T&D Losses, 2009/10 to 2016/17 (continued)

State	T&D loss trajectory (%)							
	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Madhya Pradesh	38.0	37.3	36.7	36.1	35.5	34.7	34.4	34.1
Gujarat	22.8	22.3	21.9	21.5	21.1	20.7	20.4	20.1
Bihar	41.0	41.0	40.4	38.8	37.7	36.6	35.9	35.3
Jharkhand	35.0	34.8	34.5	34.4	34.2	34.1	34.0	33.9
West Bengal	18.0	18.0	17.9	17.9	17.9	17.9	17.9	17.9
Haryana	31.0	29.8	29.5	29.3	29.0	28.8	28.6	28.4
Punjab	23.4	20.3	19.9	18.5	17.9	17.4	16.9	16.4
Rajasthan	30.0	29.3	29.0	28.4	28.0	27.7	27.4	27.1
Uttar Pradesh	33.0	31.6	29.9	29.6	27.2	25.7	24.6	23.7
Uttarakhand	25.3	25.0	23.9	23.0	22.3	21.9	21.4	21.0

Source: World Bank.

Table F.5 Assumptions for Capital Expenditures and R&M Cost—Establishing Relationships through Regression Analysis

Serial no.	State	Capital Expenditure – Sales *	R&M – NFA
1	Andhra Pradesh	Capital Expenditure = $5206.639 + (1.79) \times \text{Sales}$	$\text{R\&M} = -431.4 + (0.042) \times \text{NFA}$
2	Tamil Nadu	Not significant	$\text{R\&M} = -2320.3 + (0.43) \times \text{NFA}$
3	Maharashtra	Not significant	$\text{R\&M} = 2523.758 + (0.06) \times \text{NFA}$
4	Gujarat	Not significant: very poor results as a result of nonavailability of data	Not significant: very poor results due to nonavailability of data
5	Rajasthan	Capital Expenditure = $2810.344 + (6.3) \times \text{Sales}$	$\text{R\&M} = 281.71 + (0.0138) \times \text{NFA}$
6	West Bengal**	Not significant: very poor results as a result of nonavailability of data	Not significant: very poor results due to nonavailability of data
7	Jharkhand	Capital Expenditure = $-200.624 + (1.74) \times \text{Sales}$	$\text{R\&M} = -196.119 + (0.0963) \times \text{NFA}$
8	Bihar	Statistically nonsignificant relation	$\text{R\&M} = -807.041 + (0.155) \times \text{NFA}$
9	Uttar Pradesh	Statistically nonsignificant relation	$\text{R\&M} = -4108.48 + (0.178) \times \text{NFA}$
10	Madhya Pradesh	Statistically nonsignificant relation	Statistically nonsignificant relation
11	Kerala	Statistically nonsignificant relation	$\text{R\&M} = -353.71 + (0.028) \times \text{NFA}$
12	Karnataka	Statistically nonsignificant relation	Not significant
13	Meghalaya	Statistically nonsignificant relation	$\text{R\&M} = -32.52 + (0.061) \times \text{NFA}$
14	Orissa	Statistically nonsignificant relation	$\text{R\&M} = -5409.91 + (0.45) \times \text{NFA}$
15	Punjab	Statistically nonsignificant relation	$\text{R\&M} = -2118.87 + (0.05) \times \text{NFA}$
16	Uttarakhand	Statistically nonsignificant relation	$\text{R\&M} = 22.69 + (0.036) \times \text{NFA}$

Note: Regression results were not significant. A constant reduction of 2–3 percent has been taken.

* Sales here are defined as incremental sales (output units).

** Only 3-year data available.

***Very poor correlation result.

Notes

1. Type of fuel: coal (domestic and imported), gas, hydro, and nuclear.
2. The weights are computed by adding the capacity by category that has come online till 2010/11 to the total capacity (in that particular source—coal, hydro, gas).
3. For nuclear, we have assumed a flat fixed cost over the years.

References

- Bajaj, H. L., and D. Sharma. 2010. "Power Sector Reforms in India." New Delhi: Government of India. <http://www.worldenergy.org/documents/p001438.doc>.
- Central Electricity Authority. 2011. *Review of Performance of Thermal Power Stations 2009–10*. New Delhi: Central Electricity Authority, Ministry of Power.
- . 2012. *All India Electricity Statistics, General Review, 2011*. New Delhi: Central Electricity Authority, Ministry of Power.
- ICRA. 2012. *State-Owned Electricity Distribution Companies: Some Positives, Though Several Concerns Remain*. New Delhi: ICRA. <http://icra.in/Articles/Power%20Distribution%20Note.pdf>.
- IDFC (Infrastructure Development Finance Company). 2012. "Power: Déjà vu." PowerPoint Presentation, March 2012.
- Panda, Aurobinda, and Atul Patel. 2011. "Competition Law and Competition Issues Affecting the Energy Sector in India." *Journal of Infrastructure Development* 3 (2): 107–15. <http://ssrn.com/abstract=1873084.21>.
- Planning Commission. 2011. "Annual Report 2011–12 on the Working of State Power Utilities and Electricity Departments." Planning Commission, Power & Energy Division, New Delhi. http://planningcommission.nic.in/reports/genrep/arep_seb11_12.pdf.
- Power Finance Corporation. "Annual Reports." <http://www.pfcindia.com/Content/PerformanceReport.aspx>.
- Sharma, D. Parameswara, P. S. Chandramohan Nair, and R. Balasubramanian. 2005. "Performance of Indian Power Sector during a Decade under Restructuring: A Critique." *Energy Policy* 33 (4): 563–76. <http://eprint.iitd.ac.in:8080/handle/2074/1478/1/sharmaper2005.pdf>.

Environmental Benefits Statement

The World Bank is committed to reducing its environmental footprint. In support of this commitment, the Publishing and Knowledge Division leverages electronic publishing options and print-on-demand technology, which is located in regional hubs worldwide. Together, these initiatives enable print runs to be lowered and shipping distances decreased, resulting in reduced paper consumption, chemical use, greenhouse gas emissions, and waste.

The Publishing and Knowledge Division follows the recommended standards for paper use set by the Green Press Initiative. Whenever possible, books are printed on 50 percent to 100 percent postconsumer recycled paper, and at least 50 percent of the fiber in our book paper is either unbleached or bleached using Totally Chlorine Free (TCF), Processed Chlorine Free (PCF), or Enhanced Elemental Chlorine Free (EECF) processes.

More information about the Bank's environmental philosophy can be found at <http://crinfo.worldbank.org/wbcrinfo/node/4>.



In September 2012, the government of India revived the power generation sector through a bailout of about Rs 1.9 trillion that came in response to banks and financial institutions with large non-performing loans to the power sector. Power sector developments in the past two decades have brought new players into a traditionally government-dominated sector, and they have also been implicated in the crisis. Aside from new private sector participants, primarily in generation, the state electricity boards were unbundled into generation, transmission, distribution, and, in a few cases, trading segments. State electricity regulatory commissions were also established in all states.

Over the next two decades, India faces immense challenges if it is to sustain the 8 to 10 percent growth rate required to end poverty and achieve its human development goals. According to the Planning Commission, India needs to triple or quadruple its primary energy supply and increase its installed electricity capacity by at least five or six times its 2004 levels to meet demand in 2032. To accomplish these ambitious goals, India will need a commercially viable power sector.

Beyond Crisis: The Financial Performance of India's Power Sector describes the financial and operational performance of segments in the power sector value chain between the 2003 adoption of the Electricity Act and 2011, including the factors that contributed to the recent crisis. The book focuses on efficiency and productivity, whether performance has improved over time, and which states have emerged as performance leaders. *Beyond Crisis* aims to integrate historical performance, the current situation, and future projections of the impact of worsening sector finances as well as the actions that need to be taken to check the downturn. This book will be of interest to a wide audience, including policy makers, experts, and managers in the international development community and in academia.

The World Bank Studies series is available for free download online through the Open Knowledge Repository (<https://openknowledge.worldbank.org>).



ISBN 978-1-4648-0392-5



SKU 210392