Many Sparks but Little Light:

The Rhetoric and Practice of Electricity Sector Reforms in India

Prayas (Energy Group)

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About Prayas
Prayas - Initiatives in Health, Energy, Learning and Parenthood, founded in 1994, is a non-governmental organisation based in Pune, India. Members of Prayas are professionals working to protect and promote public interest in general, and interests of the disadvantaged sections of society, in particular. Prayas is registered as a Scientific and Industrial Research Organization with the Department of Scientific and Industrial Research, Ministry of Science and Technology, Government of India.

Prayas (Energy Group) works on regulatory and policy aspects of energy and electricity sectors. Our aim is to make energy a tool for sustainable and equitable development for all citizens. Our work includes evidence-based analysis, discourse building, and policy and regulatory engagements with a public interest focus. Outputs of Prayas (Energy Group) include innovative analysis reports, guides, tools, and policy and regulatory submissions. We contribute to the energy sector through our outputs, participation in official committees constituted by ministries, NITI Aayog and Regulatory Commissions, as well as our association with many civil society organisations and networks. For more details and accessing our publications, please visit our website: www.prayaspune.org/peg.

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Dedicated to

Girish Sant

(1966 – 2012)

Founding coordinator of Prayas (Energy Group)
who continues to inspire our work

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Foreword

Prayas (Energy Group) or, in its abbreviated form, PEG is a non-governmental, non-profit organisation based in Pune (India), active since the early nineties. It comprises of young professionals deeply committed to protecting and promoting the public interest in the energy sector, especially the interests of the disadvantaged sections. Its strength lies in its ability to analyse complex policy issues and, on that basis, undertake advocacy on behalf of the consumers.

PEG first established its credibility as a competent consumer-oriented NGO when it undertook an incisive analysis of the electricity demand trends in Maharashtra in 2001 and highlighted the technical and financial implications of the infamous Enron power project. The Expert Committee constituted by the State government to deal with Enron, of which I was a member, benefited a great deal from the professional evidence provided by PEG. Since then, PEG has grown from strength to strength, first as a group involved primarily with independent regulation in the electricity sector and later graduating into regulatory issues concerning the upstream fuel sectors, namely, coal and natural gas. PEG has done seminal work in electricity demand management and, more recently, involved itself in being a constructive critic of the policy aimed at developing renewable energy resources. All these different initiatives have taken PEG into the realm of domestic research on global climate concerns.

It is against this background that PEG has rightly chosen to take a pause and look back at the way energy policy has evolved over the decades and review the gaps in policy that still need to be covered. This publication has been the outcome of that effort.

The complexity of the energy sector arises from the fact that energy is both an intermediary input in the development process, as well as a final product that adds to the quality of life. While electricity has indeed contributed significantly to the process of economic development over the decades that followed Independence, it is worrisome that it has hardly reached only 67% of the country's households. Around 86% of the rural households still use traditional biomass fuels for cooking, which lie outside the energy markets of the country. Considering that the majority of the households have low incomes and, therefore, cannot afford to buy market-priced fuels, policy makers have the daunting task of balancing market reform with subsidies.

In this publication, PEG has comprehensively covered the reform trajectory since 1991 in each of the sub-sectors of the electricity and allied fuel sectors. The

publication covers not only the twists and the turns in the path of reforms but also their impact in terms of consumer benefit.

One would expect economic liberalisation to imply lesser government presence, greater independent rule-based regulation and enhanced competition, both domestic and global. Liberalisation was expected to enhance resource use efficiencies and help the consumers. Of course, there is always a gap between rhetoric and practice.

As far as the electricity sector is concerned, some segments of it, such as distribution, are not readily amenable to competition, though major initiatives have been taken to unbundle the sector to expose it to competition wherever feasible. In order to facilitate the entry of private investors, therefore, it is necessary to have apolitical, professional regulators to protect the interests of the consumers. Such an independent regulatory environment is yet to evolve satisfactorily in our country.

Though competitive price determination has made a modest beginning in the electricity sector with commensurate consumer benefits, with the public sector utilities continuing to dominate the sector, electricity regulation is still based largely on pricing that allows a reasonable return over and above normative costs. The fuel costs are dependent on the extent to which they are regulated in the upstream coal and natural gas sectors. Both coal and natural gas prices continue to be largely administered, leaving little room for the electricity regulator to bring visible benefits to the consumers. Private players in coal mining were restricted till recently to a few captive coal miners and competitive block allocation has just started. Though private players were allowed decades ago to enter hydrocarbon exploration and development activity, the government is yet to develop its capacity to manage and enforce the hydrocarbon production sharing contracts satisfactorily. As a result, natural gas development in the franchise areas stagnated and the electricity sector witnessed serious gas shortages that affected power supplies in the southern region.

In the case of both electricity and natural gas, attempts are being made to separate the producers from the common carrier transmission systems so as to create greater scope for competition to benefit the consumers. There is a long way to cover in this direction.

There are three major waves of change that are sweeping the energy sector globally. The first is the collective effort to contain global warming that is caused by the use of fossil fuels. Being a signatory to that global effort, India needs to reorient its own energy policy to be in tune with it. The second is the technological change that is bringing down the cost of renewable energy and introducing cleaner

technologies that are being developed to mitigate the adverse effects of fossil fuel use on the climate. During the last few years, India has taken major strides to take advantage of these trends. Lastly, civil society activism against local environmental degradation caused by large energy projects has been on the increase. It is therefore no longer easy for the government to pursue the traditional supply-centric strategy of adding new production capacity in preference to managing the demand. The energy sector reform trajectory in India is bound to react to these changes in a significant measure.

As in any other sector, there are numerous stake holders with competing interests in the electricity sector. Electricity sector policies necessarily seek to balance these interests. This adds a political dimension to the formulation of electricity policy.

This book, "Many sparks but little light", traces these developments in electricity sector policy evolution in considerable detail, tracks the conceptual trends in a highly analytical manner and identifies the gaps in reform for the consideration of the policy planners. One common thread that runs throughout this narration is the emphasis on deepening public accountability as the overarching objective of any change that the policy planners may contemplate.

There have been several books written by scholars and researchers on individual sectors of energy and the energy sector as a whole. However, very few of them are written by those who have had the benefit of interacting closely with the consumers and the policy planners in an equal measure. PEG's "Many sparks but little light" belongs to the latter category. To a policy planner, this publication can provide useful insights on the direction in which they should proceed in the coming years. To a researcher, it opens up new areas for academic investigation. To those involved in promoting consumer interest, it points to gaps which need to be bridged through consumer activism and a democratic pressure on the government to make the necessary changes.

In all, Prayas has made a great effort in bringing out this useful publication. It certainly bears the signature of Girish Sant who had visualised the institution of PEG.

Dr. E. A. S. Sarma

Preface

The year 1991 was an inflection point in the history of modern India. Beginning this year, the Indian economy was subjected to fundamental structural changes in response to a balance of payments crisis. Based on suggestions and conditions from international agencies, India embarked upon wide-ranging economic reforms in what came to be known as the liberalisation, privatisation and globalisation or LPG era. The fundamental thrust of the LPG era was on reforms to reduce the role of the government in many sectors, encourage private investment in its stead, reduce restrictions on capital flows and thus attract international players, capital investment and current technology. It was claimed that these reforms would introduce structural changes in the economy and increase efficiency, thus resulting in faster growth. In turn, the economic growth was expected to help address the balance of payments crisis and help pull many Indians out of poverty.

The electricity sector — indeed, the entire energy sector — was mostly controlled by the government in the early 1990s, and continues to be a highly capital intensive sector. It was also a fiscally strained sector suffering from a shortage of supply. For all these reasons, it has been a major target of multiple waves of reforms during this period. For example, the private sector was invited to participate in electricity generation, electricity boards were unbundled and corporatised (with some even being privatised), oil and gas exploration and production were opened up to markets and competition, and the coal sector experimented with allocation of coal blocks for captive consumption. In the electricity sector, the guiding principles of reforms were emphasising markets rather than centralised planning, globalisation rather than self-reliance, and treating electricity much more as a saleable commodity rather than as an important input to human development.

Over the years, there have been many analyses, opinions and critiques of reforms in the electricity sector. In 2000, the independent energy analyst Abhay Mehta published a critique of the reforms in his book *Power Play: A Study of the Enron Project*. This book focuses on the infamous Dabhol power project to bring out the many issues pertaining to the 'Independent Power Producer' approach. Joel Ruet, a specialist in emerging economies, authored and edited four books between 2002 and 2006 titled *Against the Current* (Volumes I, II and III) and *Privatising power cuts*, which focus on the restructuring of Indian State Electricity Boards (SEBs). In these books, he teased out different perspectives of SEB restructuring and the Electricity

Act, and covered issues such as reform experiences in some states, challenges in agriculture, better management of distribution, and options to improve the working of SEBs. The Indian Institute of Public Administration published a report titled *Study on Impact of Restructuring of SEBs* for the Ministry of Power in 2006 which has case studies of twelve states and makes several observations and suggestions about the reforms process. This report points out that while restructuring was necessary, it was not sufficient to improve the sector, and notes that restructured utilities were still not professionally managed which limited their efficiency.

Navroz Dubash, an expert on governance and political economy of energy, and Narasimha D Rao, an expert on energy systems and human development, authored the 2007 book *The Practice and Politics of Regulation: Regulatory Governance in Electricity,* which studies electricity regulators in three states of India, and examines the challenges faced in institutionalising these supposedly independent new agencies. Ajay Pandey and Sebastian Morris of IIM Ahmedabad published a report titled *Electricity Reforms and Regulations: A Critical Review of the Last Ten Years' Experience* in 2009 for the Forum of Regulators. This report makes the point that while the reforms have had major impacts, they did not necessarily take steps in the intended direction, and that the main problems of leakages, viability of distribution, tariff reform and competition still remain unaddressed. *Powering India: A Decade of Policies and Regulation* edited by S. L. Rao, former chairperson the Central Electricity Regulatory Commission, was published in 2011 and analyses crucial policy reforms in the electricity sector over the last decade.

The 2014 book *Electrifying India: Regional Political Economies of Development* by Sunila Kale, Associate Professor at the University of Washington, analyses the electricity sector from a political economy lens and provides an excellent narrative of the developments in the sector from this perspective. The World Bank published a series of four reports in 2014 and 2015 titled *Private Participation in the Power Sector: Lessons from Two Decades of Experience*, *More Power to India: The Challenge of Electricity Distribution*, *Governance of Indian State Power Utilities: An On-going Journey* and *Beyond Crisis: The Financial Performance of India's Power Sector*. The gist of these reports is that while some aspects, such as generation privatisation, adding grid-connected solar and a few experiments with franchisees and distribution privatisation have worked well, many other aspects such as distribution utility governance and finances, rural access and quality of supply, regulatory autonomy and effectiveness, public availability of high quality data, and efficiency of upstream generation have a long way to go. This list of analyses and critiques of electricity

sector reforms is by no means exhaustive. For example, the pioneer of appropriate technology, Amulya Reddy and his colleagues published many articles in the Economic and Political Weekly in the 1990s. Authors from Prayas (Energy Group) have also written many articles on various aspects of the reforms through the 1990s and 2000s.

It has been a quarter century since the beginning of the reforms, as evidenced by a spate of opinion pieces and newspaper articles in July 2016. There are indications that a fresh wave of reforms are in the offing in the electricity sector, such as separating 'carriage' and 'content' in electricity and introducing commercial mining of coal. The sector is also buffeted by major technological changes which are resulting in rapidly falling renewable energy prices, which is likely to lead to seismic changes not only in the economics of the sector but also its very structure, because of an increased role for aspects such as on-site generation, electric vehicles and affordable storage. Increasing concerns about environmental implications of energy, including climate change, are also drawing policy responses from governments around the world including the Indian government. It is therefore an opportune time to review the reforms so far and see whether they succeeded in achieving their objectives and desirable social and environmental goals. A better understanding of the reasons behind their failure or success can help to shed light on informing future reforms in the sector.

That is the primary motivation in writing this book. It attempts to critique the major reform experiments of the past — defined as those which could have had a significant impact on the sector. The lessons thus learnt can help to improve the design and implementation of further reforms, so that the sector overcomes its challenges in an equitable and sustainable manner. It is also important to be clear about what the book does not cover. It does not provide a comprehensive review of *all* reforms in the electricity sector over the last quarter century, nor does it attempt to provide a blueprint for the future of the sector.

Having started its work in the early 1990s, the journey of Prayas (Energy Group) runs more or less parallel to India's electricity sector reforms. Over this period, we have keenly followed and participated in the reforms process as a proactive, independent organisation offering constructive critique and suggestions to further public interest. We have criticised the lapses of the Independent Power Producers era with episodes such as Enron, provided inputs to shape the era of Electricity Regulatory Commissions and the Electricity Act of 2003, participated in various

policy and regulatory committees, and intervened before regulatory commissions on public interest and consumer related issues. Our work has focused not only on the substantive aspects of the sector, but also on matters related to institutions and processes. These activities have helped to sharpen our understanding of the sector and informed our on-going engagement with it. This unique understanding and engagement with the sector has led to this book.

The book would be relevant to civil society, policy makers, regulators, investors and researchers who wish to understand the twists and turns of the Indian electricity sector over the last twenty-five years. We have tried to present it as an informative resource for any person interested in understanding and engaging with the electricity sector. It is our hope that the book will engage your attention and that you enjoy reading it.

Prayas (Energy Group)

January, 2017

Acknowledgements

Over the years, the work of Prayas (Energy Group) has been informed and enriched by interactions with the research community, the government, civil society organizations, consumer groups, trade unions, industry and regulatory institutions. This has helped to hone our understanding of the reforms in the sector, and thus also in producing this book. We are grateful to all of them for this productive engagement.

This book has evolved through several drafts. We have immensely benefited from the critical but constructive feedback received from many patient reviewers at different stages. For this, we are very grateful to Ajit Abhyankar, Ranjit Bharvirkar, Anish De, Navroz Dubash, Milind Murugkar, Nandini Oza, Ajit Pandit, Anant Phadke, V P Raja, Ashok Rao, Narasimha D Rao, Rammanohar Reddy, E A S Sarma, Daljit Singh, Himanshu Thakkar, Neeraj Vagholikar, A. Velayutham, Mahesh Vipradas, all our colleagues at Prayas (Energy Group) and a reviewer who prefers to remain anonymous. We are also grateful to Dr. E A S Sarma, the former Union Power Secretary who continues to be active in the power sector, for readily agreeing to write the foreword to the book. Particular thanks go to Neeta Deshpande for her painstaking review and copy-editing of the various drafts of our book. Finally, we thank Mudra and Sujit Patwardhan for helping us to publish this book under tight deadlines.

Needless to say, we are solely responsible for the final content of the book.

1

The long and winding road of electricity sector reforms in India

"Success does not consist in never making mistakes but in never making the same one a second time"

- George Bernard Shaw

Reliable, affordable electricity service is essential to improve the quality of life, provide community services and support income generation. However, generation and supply of electricity comes at a high cost, with considerable strain on our scarce national resources, fragile environment and people's livelihoods. Therefore, it is imperative that electricity policies and plans aim to reduce poverty and impoverishment, while minimising strain on resources, the environment and livelihoods. In other words, electricity should catalyse development. The normative goals of the sector should be universal access, good quality supply and service, affordable tariff, and sustainability. To meet these goals, it is important to have a robust electricity sector that is financially sustainable while also being conscious of the concerns of equity and ecology.

Sensing that these goals were not being met, Indian policy makers initiated several changes in the sector over the last two and a half decades. Based on their understanding of the underlying challenges, changes were introduced, initially to meet the stated objectives of attracting investments and making the sector financially viable. These changes can be loosely called 'reforms'. The 'reform' process in the electricity sector began in the early 1990s, coinciding with and also driven by the economy wide reforms aimed at liberalisation, privatisation and globalisation. It covered the generation, transmission, distribution and related fuel sectors, namely coal and gas. This reform process, involving major changes in policy, structure and ownership, has slowly increased the role of the market and private players in a

sector which was largely publicly owned. Such changes are on-going even today while more are being planned.

Over the last two and a half decades of reforms, there have been many changes and taking stock of all of them is not easy. But one can confidently say that universal, affordable, quality access to electricity is still many years away, even after all these changes. The sector operations continue to pose serious challenges to the environment and people's livelihoods. Hence we submit that, prima facie, the reforms have generally disappointed. Reforms have failed to meet the stated objectives of attracting investment and making the sector financially healthy. What is worse is that the failure is not limited to these outcomes. There have been short-comings in understanding and addressing the real problems as well as the inability to make suitable midcourse corrections. These limitations have resulted in poor progress in the crucial areas of universal access, affordable tariff and sustainability.[1] These failures can be traced to limitations in planning, implementation and public oversight of the reforms.

Reflecting on what went wrong, one school of thought argues that the reforms did not do enough to enable market operation and hence failed to deliver. This school would naturally suggest a stronger push for competition as a way of dealing with the sector's current challenges. There is another school of thought, which would equally forcefully argue that the failure was on account of powerful vested interests, which did not allow any real competition, but also prevented the public sector entities from functioning properly. This school of thought will hence suggest that our systems are not yet geared for market transition and that we need a better and stronger public sector. Some others would argue that a critical infrastructure sector like electricity should remain entirely in public hands, but with better accountability mechanisms. There have also been debates on the relative roles of central and state governments in the sector. While there is some merit in all these arguments, we feel that the truth is somewhere in between.

While the shortcomings of state owned electricity boards were clear from the 1980s, the experience of market oriented electricity reform the world over has been mixed, and in some cases disastrous, like the California crisis. There is no concrete evidence to demonstrate that any one solution has worked consistently across time or geography.

1. It must be mentioned that during the initial reform period, there was no explicit emphasis on goals such as universalisation of access, accountability of institutions, transparent processes to enable a level playing field, and ensuring social equity and environmental sustainability. Some attempts to include these goals were made in subsequent years, but with limited enthusiasm and rigour. However, these attempts have indeed yielded some positive results.

The challenge before the Indian electricity sector is massive and has multiple dimensions like universalisation of electricity access for a large population, working with limited natural resources, and meeting the rising local and global environmental concerns. To address this challenge, it would not be wise to opt for any one of the extreme options, be it private vs. public or monopoly vs. competition. Taking any extreme position drives the focus away from the essential hard process of institutionalising transparency, accountability, public participation, and building capacity of all sector actors. Whatever be the model, we believe that this process is crucial to develop and sustain a healthy sector. With this understanding, we have undertaken this study of the long and winding road of electricity sector reforms in India.

Our attempt is to uncover the reform story so as to consolidate lessons which would help everyone in the years to come. For this purpose, we examine the progress made towards meeting the stated and normative objectives of reforms as well as the intended or unintended impact on other aspects of the sector or the wider economy, society and environment. The focus is largely on the electricity sector, and within the sector, the generation and distribution sectors are covered in greater detail. For the sake of convenience in analysing and presenting the reforms story, we divide generation into three broad categories: thermal, hydropower, and renewables. Similarly, coal and natural gas, the two most important fossil fuel sectors, are covered in the context of their crucial linkages with the electricity sector.

Some areas of the electricity sector — such as energy efficiency and nuclear energy — are not covered in this book. Energy efficiency is an important area and has been addressed briefly in Chapter 5, *Electricity distribution: On square one, even with reforms after reforms*. Nuclear energy is an opaque sector with limited information in the public domain, making detailed analysis difficult. At 5,780 MW, nuclear power accounts for only 2% of the installed capacity and 3% of the total generation. The government has ambitions plans of building 63 GW of new nuclear capacity by 2032, subject to fuel supply being ensured (GoI, 2015, p. 10) However, the past performance and the global trends and uncertainties on cost, fuel supply, safety, waste disposal, project delays and public opposition suggests that this target is unlikely to be met. Hence, in all likelihood, nuclear power may continue to play a rather limited role in the Indian electricity sector. While this is true, one cannot ignore its significance from the point of view of the broader context. Even for the limited capacity that is under construction and that may get added in the future, concerns regarding the risks it poses to public safety, environment and geo-political relations are hardly trivial. However, these are issues beyond the scope of this book.

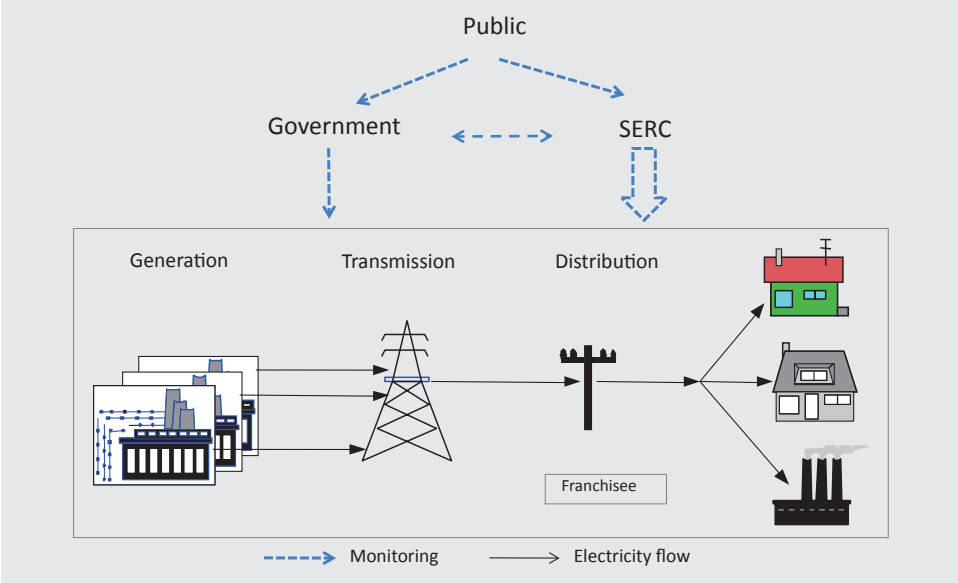
A good reference for those interested is the book "*The Power of Promise: Examining Nuclear Energy in India*", by Dr. M.V. Ramana (Ramana, 2012).

This overview chapter briefly introduces the electricity sector and reforms. It is followed by chapters covering thermal generation, large hydropower, renewable electricity, distribution, coal and gas sectors. In coal and gas sectors, the focus is on issues related to electricity generation. Transmission is briefly covered in the distribution chapter. The last chapter outlines our broad conclusions and suggestions.

1.1 A brief outline of the electricity sector

Electricity is in the concurrent list of the Indian Constitution, with the state and central government having identified roles. The state government is primarily involved in generation, transmission, distribution, policy making, budgetary support and regulatory functions limited to the state boundaries. This is carried out by the state energy department, generation, distribution and transmission companies, the load dispatch centre and the electricity regulatory commission. In addition, some of the companies operating in the state can be owned privately or by the central government. Distribution companies may sub-contract distribution in some areas to franchisees. Figure 1.1 is a schematic of the major organisations at the state level. This is a simple representation without complexities like multiple companies, electricity traders, and consumers generating electricity.

Figure 1.1: Schematic of a typical state electricity sector



The responsibilities of the central government include preparing the national legal and policy framework, regulatory and safety guidelines, implementing centrally sponsored programmes, country-wide planning, multi-state generation projects, and inter-state transmission systems. This is carried out by the Ministry of Power (MoP), the Ministry of New and Renewable Energy (MNRE), the Central Electricity Authority (CEA), central generating companies like NTPC (earlier known as the National Thermal Power Corporation) and NHPC (earlier known as the National Hydro Power Corporation), the transmission company POWERGRID, the load dispatch operator Power System Operation Corporation Limited (POSOCO), the Central Electricity Regulatory Commission (CERC) and the Appellate Tribunal for Electricity (ATE). Nuclear energy, which currently plays a relatively small role in electricity generation, is under the Department of Atomic Energy (DAE). The Electricity Act 2003 (referred as E Act) and related central policies (National Electricity Policy, Tariff Policy, Rural Electrification Policy, Hydro Policy, etc.) prepared by the MoP provide the legal and policy framework for the entire country. There are also national missions for energy efficiency, solar and a proposed mission for wind power, as well as national programmes for rural electrification and distribution improvement.

1.2 Tracing the electricity sector from the 1990s to 2016

At the time of independence, the Indian electricity sector was very small with an installed capacity of 1.4 GW, and was largely controlled by private companies and limited to big cities and industrial centres. The State Electricity Boards (SEBs) were formed in the 1950s under the Electricity Supply Act 1948 to extend supply beyond cities. The SEBs remained state government owned vertically integrated monopolies for several decades, with the government making key decisions on budgetary support, appointments, tariffs and investment. Vertical integration implied that the SEB handled the functions of generation, transmission and distribution of electricity. After the formation of SEBs, there was commendable growth in generation capacity, number of electricity consumers, number of agricultural pumps, and the length of the electricity network. There was also significant development in technological capabilities and the presence of skilled, committed personnel.

This commendable growth was the result of four broad policies. The first was the government's ownership and support from central and state budgets. The second was the development of a centralised electricity supply system and of regional and national electricity grids. The third major policy was the thrust on self-reliance

in technology and fuels. Under this policy, autonomous but government-owned companies like Bharat Heavy Electricals Limited (BHEL) were created to develop technological capabilities. Similarly, emphasis was laid on utilisation of the available energy sources such as coal and hydropower. Finally, the policy of cross-subsidy, i.e. rich consumers subsidising the poor, was adopted widely, which reduced the tariff for small homes and agriculture.

In addition to the SEBs, the central government played a significant role in the electricity sector. The Department of Power[2] was responsible for legal and policy formulation in conventional electricity, and the Department of Non-Conventional Energy Sources[3] for the promotion of renewable energy. The Central Electricity Authority (CEA), set up in 1951, had significant roles of national level planning, regulation and data collection. With a view to speed up generation capacity addition, the central government set up the National Thermal and Hydro Power Corporations (now NTPC and NHPC respectively) in 1975. It also set up a national transmission company, POWERGRID, to construct and operate inter-state transmission to transport the power generated across the country.

1.2.1 Beginning of reforms

The SEBs performed satisfactorily till the 1980s. From then on, there was a deterioration in performance, which can be traced to failures on four fronts: techno-economic (high technical losses, low efficiency, poor project implementation); policy (poor targeting of subsidy, reducing support to the public sector); planning (over-emphasis on centralised supply approach, neglect of end-use efficiency), and governance (undue interference in SEB functioning by the state government, corruption, project delays, bad management). There were many attempts to study these failures by government committees and funding institutions like the World Bank. Several suggestions made by government committees like the Rajadhyaksha committee of 1980 were not actively implemented.[4] World Bank reports (World Bank, 1993a) and the Sharad Pawar led NDC Committee Report (1993–1994)

2. The electricity sector was managed by the Department of Power in the Ministry of Energy, until the Ministry of Power (MoP) was set up in 1992.

3. Renewable energy was under the Commission for Additional Sources of Energy (CASE) set up in 1981, the Department of Non-Conventional Energy Sources (DNES) in 1982, and the Ministry of Non-Conventional Energy Sources (MNES) in 1992. In 2006, its name was changed to the Ministry of New and Renewable Energy (MNRE).

4. Suggestions not implemented include better targeting of subsidy (only poor rural and urban consumers need subsidy — not all agriculture or rural consumers), 100% metering, higher focus on rural electrification, improving efficiency of SEBs, setting up statutory body to decide tariffs, etc., (GoI, 1980).

provided suggestions which were more in line with the Liberalisation, Privatisation and Globalisation approach[5] of the government in the 1990s. The inability of state utilities to raise finances was considered as the main problem, and privatisation suggested as the solution to address all ills of the sector. This was in accordance with other energy sector policies during this period, such as efforts to encourage private participation in oil and gas exploration and production.

Reform measures were implemented with this understanding from the 1990s and continue to this day. During the period from 1990 to 2016, there have been significant changes in electricity generation, consumption and rural electrification. These are captured in Section 1.2.4. The installed generating capacity increased by 4.5 times, from 64 GW to 289 GW. The state government sector owned 74% of the capacity in 1990, where as in 2016, the shares of state, the central and private sectors are nearly equal, with private sector ownership marginally higher at 40%. The per-capita electricity consumption has increased from 329 units/capita/year in 1990 to 1075 units/capita/year, amounting to a 3.3 times increase. Village electrification has increased from 81% to 98% and household electrification from 42% to 67%[6]. From a situation of 17% peak shortage in 1990, there is a prediction of 3.1% peak surplus in 2017. There have also been major changes in utility structure, ownership, policy and regulation, which are described in the book and briefly captured in Table 1.1, in Section 1.4.

The massive changes that took place in the sector in the last two and half decades could be called 'market oriented reforms',[7] since the primary thrust and attention was to transform electricity into a market commodity as opposed to a development input. For convenience, we cover this in two periods. The first period is from the entry of private generators and SEB restructuring in 1990s to the formulation of the Electricity Act in 2003. The second period starts with the Electricity Act 2003, which provided a national legal framework for reforms, and covers developments till today.

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5. Recommendations in Chapter 11 of the report include a) unbundling the SEBs, reduction of equity of state governments, privatisation of distribution in urban areas (recommendation 2), b) formation of tariff boards at regional level for commercialisation of the sector (recommendation 5), and c) encouraging privatisation (recommendation 10) (Planning Commission, 1994).

6. Household electrification was 67% and rural household electrification 55% as per Census 2011. Recent government reports indicate significant progress in rural electrification and show 71% rural household electrification (REC, 2016).

7. We are broadly using the term market, even though the initial phase of reforms largely focused on just privatisation, without any emphasis on competition or efficiency. However, one can hypothesise that the ultimate aim to enable market operation and privatisation was seen as the crucial first step towards such a new sector structure.

1.2.2 The first round of reforms — 1990s to 2003

During this round, there were many initiatives at the national level and in different states which triggered these reforms. For convenience, we cover developments during this round in two sub-sections, namely generation privatisation (starting from 1990s) and restructuring State Electricity Boards (starting with Odisha in 1996).

Generation Privatisation and Unbundling

Conventional generation projects usually have long gestation and payback periods and hence need huge upfront investments. Thus, when the large-scale reforms were initiated in the power sector in 1991, the primary focus was on the generation sector. Of course, there were other reasons for this focus as well. The power sector reforms were initiated as a part of the structural adjustment programmes which were conditions for securing the loan from the International Monetary Fund (IMF) (Weinraub, 1991; Upadhyay, 2001). Internationally, the IMF and the World Bank were pushing for more privatisation and market-based operations in sectors like power and water, and the same approach was introduced by them in India. The fact that many state electricity boards were reeling under financial stress helped to channelise the reform agenda in this direction. The narrow focus on ownership and investment led to a neglect of certain key governance and planning sectors which were ailing and continue to plague the electricity sector even today.

In the build up to the reforms, international institutions such as the World Bank were actively advocating unbundling[8] of the power sector as a solution for all the 'developing economies', and were strongly in favour of an increased role for privatisation, competition and independent regulatory bodies (World Bank, 1993a). While no specific analysis or study of the exact issues facing the Indian power sector was undertaken, the Bank proposed a three-pronged approach for power sector reforms in India. The essential elements of this reform were to introduce private sector participation in generation, to begin with, elimination of subsidies to make the sector more attractive for private investments, and to establish an independent regulatory body to ensure smooth market operation.

Through the late 1980s and the early 1990s, many countries undertook a fundamental restructuring of the electricity sector to 'unbundle' the vertically integrated utilities.

8. Traditionally, the electricity sector has been vertically integrated with the same company engaging in generation, transmission and distribution. Unbundling refers to breaking up of such an integrated company into separate companies dealing with each of these functions. The main objective of such unbundling is to enable competition in generation as well as retail supply.

On the sheer power of the idea, this model soon became the conventional wisdom in the power sector (Dubash & Singh, 2005). Generation was considered to be more amenable to competition, while distribution and transmissions were allowed to be 'natural monopolies', meaning that it was better to have only one operator in an area. While different models have been tried by different countries, there is no concrete evidence of efficiency gains on account of increased competition in generation (Ghosh Banerjee & Pargal, 2014, p. 137). The issues pertaining to competition in generation are dealt with in greater detail in Chapter 2, *Too good to be true: The story of thermal generation*, and Chapter 3, *Reforms in hydropower: Missing the woods for the trees* which deal with thermal generation and hydropower respectively. The unbundling model and regulatory structure championed by the Bank was first adopted by the state of Odisha in 1996, and later became a part of the country's power sector through the Electricity Regulatory Commissions Act 1998 and the Electricity Act 2003.

In 1991–92, the country launched its power sector reforms by opening its generation sector to private and global investors. The basic rationale for this move was that the government did not have resources that the development of the electricity sector needed, and hence it was felt necessary to involve the private sector. "The need of all-round development is putting a heavy burden on our limited resources. Mobilisation of resources for achieving self-sufficiency in electricity sector assumes high priority", states 'India's Electricity Sector — Widening scope for private participation', the April 1992 publication of the Government of India, which is a compilation of the changes introduced as a part of the reforms and incentives provided to the private sector. Later on this policy came to be known as the Independent Power Producers (IPP) Policy (GoI, 1992, p. 1).

Stating various constraints, the government claimed that it could provide incremental capacity addition of about 31,000 MW in the next five years, as against the Planning Commission working group recommendations of 36,645 MW. With this background, it was resolved to mobilise additional resources by encouraging greater private sector participation. For meeting this stated gap in investment of about 5,645 MW, the government completely opened up the electricity generation sector with a package of policy measures, which it claimed would attract profitable investment opportunities. For this purpose, the government changed laws and regulations and offered a set of incentives to make investments lucrative. As the main objective of the new policy was to bring in additional resources for the capacity addition programme in the electricity sector, a few conditions were also introduced.

At least 20% of the outlay was to be equity, and the promoter was to bring in at least 11%. Moreover, the funds that could be raised from Indian public financial institutions were not to exceed 40% of the total outlay. While the policy discussed faster clearances and speedy processes for fuel linkages, issues such as feasibility of coal production[9] to meet the new generation capacity, its transportation, and other such constraints were not deliberated upon.

On the face of it, this policy initiative was wildly successful. Some 243 Memoranda of Understanding (MoUs) for over 90,000 MW of capacity — 16 times more than the stated shortfall, and also more than the country's total installed capacity at that time, were signed. As a result of this ambitious policy decision, the generation sector underwent crucial legal, policy and governance changes. Though the policy aimed at encouraging generation capacity addition of all kinds, including large hydropower and renewable energy sources, the most enthusiastic response was from the thermal (gas and coal) generation segments.

In spite of the frenzied response, the projects were not selected through an open and transparent bidding process, and the terms and conditions of the MoUs and the power purchase agreements (PPA) were strictly guarded as 'confidential' documents, not accessible to the public. As a result, many of these projects were based on imported fuel and technology, and were linked to currency price variations. Such factors increased the level of uncertainty regarding pricing of this power while also increasing the overall cost that the consumers had to bear. Most importantly, the issue of demand estimation, i.e. how much power was actually needed or could be consumed and whether the IPP generation was the least cost, best option for meeting this demand, was not even a part of the policy discourse.

As it happened, most of these projects remained only on paper. Still, it was difficult to lament about this failure, because even if a few of these 200 odd projects had actually materialised, not only would the SEBs have become bankrupt, but on account of the sovereign guarantees, even the state and central governments would have come under severe stress.

One of the most important lessons that emerged from the IPP policy failure was the need to introduce bidding as a method of selecting a project. While a further set of reforms factored in this learning, not much attention was paid to the other crucial failures. There continued to be a disproportionate focus on attracting private

9. Coal is the only domestic fuel which is considered to be abundantly available, though of poor quality.

investments. As a result, efforts towards enabling proper demand assessment and rational power purchase planning, instilling transparent processes for monitoring and regulation, and creating a level playing field for competition, remained neglected. Similarly, issues pertaining to fuel sector planning and governance also did not get due attention. The generation reforms continued with a single minded focus and increased thrust on private sector participation.

Restructuring of State Electricity Boards

As discussed earlier, unbundling the electricity sector was accepted as the approach to enable competition and privatisation. Restructuring of State Electricity Boards (SEBs) involved functional unbundling of the SEB into three components — generation, transmission and distribution, and the formation of an independent electricity regulator. Apart from the objective of privatising generation, the narrative supporting restructuring was that the SEBs are not well managed due to high political interference, and that they do not have the financial health to remove electricity shortages, expand distribution infrastructure, or provide quality supply to consumers. It was argued, primarily by funding agencies (like the World Bank and Asian Development Bank), as well as mainstream sector actors (like the Ministry of Power, politicians, consultants and industry associations), that SEBs are becoming a financial drain on the state governments, and restructuring, privatisation and competition would solve the problem. In the restructured set up, generation and distribution functions would be managed by many separate companies (which may later be privatised), whereas transmission would be managed by one company (typically state owned). All the companies would be regulated by an independent regulator, appointed by the government. Regulatory commissions were expected to make decision making more professional, prevent undue political interference, and attract private investment. SEB restructuring started with Odisha state in 1996 and was adopted by several states. Privatisation of distribution took place only in Odisha in 1999 and Delhi in 2002.

The stated objectives of the reform plan in Odisha were to overhaul the loss-making sector, bring in massive capital investment, and privatise operations, so that over a period of a few years the sector would become profitable. As explained in detail in Chapter 5, *Electricity distribution: On square one, even with reforms after reforms*, the Odisha SEB was unbundled into four Distribution Companies (DISCOMs), one Transmission Company — GRIDCO and one Generation Company in 1998. The Transmission Company remained state owned, whereas the thermal generation and distribution companies were privatised. The American

multinational AES took 49% stake in the existing thermal generation company. DISCOMs were privatised in 1999 with AES taking control of one and the Bombay Suburban Electricity Supply Company (BSES) of three DISCOMs.[10] The Odisha State Electricity Regulatory Commission (OERC) was set up in 1996. After a few years of the reforms, it became clear that the performance of the sector had not improved as planned. As soon as the reforms began, the state government stopped subsidy to the sector, perhaps with the expectation of a quick financial turnaround. However, electricity demand did not rise as planned, transmission and distribution losses did not reduce as expected, losses of the state-owned transmission company piled up, private distribution companies could not improve the distribution system or access levels, and the tariff kept rising. In the face of high losses, the finances of the sector continued to be in trouble. One of the four private distribution companies, AES, abandoned it in 2001, and in 2015 the OERC revoked the licenses of the other three BSES companies.

In a short span of a few years between 1998 and 2001, several states quickly followed the Odisha model of power sector reforms, before the results from Odisha were visible or analysed. States which initiated reforms with World Bank support were Haryana, Andhra Pradesh, Uttar Pradesh, Karnataka and Rajasthan. Madhya Pradesh, Gujarat and Kerala received support from the Asian Development Bank (ADB). Many other states went ahead without any external funding support. Most of these states enacted their own electricity reforms acts, formed regulatory commissions and unbundled SEBs. But privatisation was not taken up in any of these states. In 1998, the central government enacted the Electricity Regulatory Commissions Act, under which the Central Electricity Regulatory Commission (CERC) was set up. The CERC played the role of regulating inter-state generation and transmission projects. This Act also facilitated many more states to undertake restructuring of SEBs and set up Electricity Regulatory Commissions.

Privatisation in Delhi did not follow the Odisha model, but benefited from the many lessons regarding its shortcomings. There was no intermediate corporatisation or any involvement of multilateral agencies like the World Bank. The government provided support for the transition. There are three private companies handling distribution in Delhi. There were some improvements on the ground like significant

10. The AES Corporation is a large multinational power company based in the US. Its Indian arm had taken over one distribution company in Odisha. The Bombay Suburban Electricity Supply Company (BSES) has a long history of managing distribution in suburban Mumbai. Reliance Industries took over BSES in 2002, forming Reliance Energy, which expanded to Reliance Infrastructure Limited in 2008.

reduction of losses and improvement in quality of supply. But the result of the privatisation experience has been mixed, despite having an urban consumer base and state government subsidy support, as discussed in Chapter 5. Distribution companies have accumulated financial losses and regulatory oversight on important issues like power purchase, capital expenditure, and estimation of losses has been weak. The Comptroller and Auditor General audited the private companies in 2015, but the report is not public. As we write this, the state government has been threatening to revoke the licenses of two companies, and there is a tussle between the state government and the Lieutenant Governor over the appointment of the Chairman of the Regulatory Commission.

By 2003, SEBs were unbundled in 9 states, Regulatory Commissions set up in 22 states and distribution privatised in Odisha and Delhi (MoP, 2003). Privatisation of distribution was planned as part of the reform plan in many states, but was not adopted due to the failure in Odisha and political opposition in other states. There was an understanding even in official circles that advised a cautious approach to privatisation as reflected in this quote from an International Monetary Fund working paper: "… it is important for India to avoid the mistakes that Latin America made in the 1990s by hastily embarking on an overly ambitious agenda of economic liberalization and privatization that ran ahead of the supporting institutions or the productive abilities of their economies" (Rodrik & Subramanian, 2004).

A major turning point in electricity reforms was the Electricity Act 2003. After reform initiatives in a few states, the central government started working on a national legislation to provide a common framework for reforms across the country. Its provisions include making private participation in generation easier, introducing electricity markets, mandating the formation of Electricity Regulatory Commissions, etc. We cover more details in the next section.

The story of transmission is different. In the initial years of SEBs, state transmission grids were developed. From the mid-1960s, there was a focus on developing regional transmission grids by interconnecting state grids. The five regions are North, East, West, South and North-East. From the mid-1970s, central sector transmission systems were set up which connected states and regions. POWERGRID, a public sector company owned by the Government of India, largely owns and manages the inter-state transmission system today. A code for operation of the grid, the Indian Electricity Grid Code (IEGC), was issued in 2000 by the Central Electricity Regulatory Commission. From then on, there has been steady progress in

connecting the entire country to one grid. When SEBs were unbundled, a separate transmission company was set up in each state. As for privatisation and competition, the first step in the transmission sector was the 1998 amendment to the Electricity Act 1910 which recognised transmission as a separate activity. In 2000, the Ministry of Power issued guidelines for private participation in transmission, with two options. The first was the formation of a joint venture with the state or central transmission company, and the second was the formation of an independent private transmission company. Competitive bidding was introduced in 2006. However, for many years, there was limited interest in privatisation of transmission. Even today, the transmission sector remains largely public owned.

Before concluding this section, it is relevant to briefly mention the efforts to promote renewable energy and end-use efficiency. With supporting policies from the mid-1990s, there was growth in renewable energy capacity, mainly in wind, biomass and small hydropower, as described in Chapter 4, *Renewable Energy (RE): The imperative for the future*. These renewable energy projects were set up mostly by private companies. As for end- use efficiency, there were many disjointed efforts at state and national levels, but a comprehensive national Energy Conservation Act was enacted in 2001. This Act set up the Bureau of Energy Efficiency (BEE), with roles for promoting energy efficiency codes and norms. State governments were also to identify agencies for promoting energy efficiency and in all states, the existing state renewable energy development agency was given this additional responsibility. As described in Chapter 5, from 2015, there have been national initiatives to promote LED based lighting on a large scale and pilot projects involving efficient fans and agriculture pump sets.

1.2.3 Electricity Act 2003 and beyond

The Electricity Act 2003 (E Act) marked a watershed in the Indian power sector, with fundamental and far-reaching impacts. It aimed to increase competition in the sector by delicensing generation, facilitating open access, and introducing power trading. It provided a comprehensive national legal framework for the Electricity Sector. The E Act overrides all existing acts governing the power sector, namely the Indian Electricity Act (1910), Electricity Supply Act (1948), Electricity Regulatory Commissions Act (1998), and the State Reform Acts. The important features of the E Act are mentioned in the following paragraphs.

Thermal Generation

The Electricity Act made generation (excluding nuclear and large hydropower[11]), a completely de-licensed activity. The Act lays special emphasis on promoting renewable technology based generation and even mandates the distribution companies to meet a certain part of their power purchase from renewable sources. Thus, any company with the necessary fuel resources and approvals and clearances (mainly for land acquisition and environment) could set up a generating plant anywhere in the country. It allowed industries to set up captive plants for their own consumption and also gave (a certain set of) consumers the choice to select their power supplier through the open access mechanism.

In this new scheme of things, distribution companies can undertake competitive bidding to *discover* the lowest tariff as per a transparent bidding process, which is defined under the guidelines issued by the central government for this purpose. They can also continue to procure power from state and centre owned plants under a 'cost-plus' regime under which the Regulatory Commissions approve and evaluate prudence of capital cost and *determine* the generation tariff on an annual basis with a fixed return on equity. It also empowers regulatory commissions to award licenses for the trading of electricity. This feature coupled with the delicensing of generation and open access (see 'Distribution sector' in this section for a brief explanation) has led to the development of what is termed as 'merchant capacity'. Unlike projects based on bidding or MoU, the merchant capacity may not have a pre-identified buyer and is hence dependent on the market. For new thermal plants which have a high payback period and are mostly expected to operate as base load units, such operation entails significant risks.

On account of all the factors mentioned above, capacity addition got a major boost because of the Electricity Act. Since 2003, coal based thermal capacity of more than 40 GW has been contracted under the competitive bidding framework. The installed thermal capacity has more than doubled from 92 GW in 2008 to about 210 GW in 2016.

While significant capacity addition has happened, costs and viability continue to be an issue. Much of the gas based capacity is stranded for want of fuel and many of the coal based competitively bid projects are seeking post-facto revision of the quoted tariff on various grounds.

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11. As per Section 8 of the Electricity Act 2003, hydropower projects need concurrence from the Central Electricity Authority, which involves among other things, a prudence check on capital investment, dam design, safety, a water utilisation policy for the region, etc.

Hydropower sector

Unlike thermal generation, private sector interest in large hydropower projects has been lukewarm, though many schemes and policies have been introduced to attract private investments in this area. Hydropower is considered to be an ideal source to meet peak demand, though several projects do not meet this objective. This is because the nature and the purpose of the hydropower project (run of the river, pumped storage or a large dam) along with other factors may put constraints on whether and to what extent it can contribute towards meeting the peak demand. While recommending premium tariffs to hydropower for this service (which were never implemented), the reforms never developed a framework that would establish the extent to which each project would actually meet peak loads. In absence of such a framework, it was neither possible to determine the extent of this benefit, nor ensure that incentives were given to the right projects.

One of the most challenging aspects of hydropower development has been the uncertainty regarding the 'final' cost and actual generation. Interestingly, in the early years of the reforms, the Sambamurti Committee (1997) set up to examine "promotion and development of hydroelectric projects in the private sector" noted that the core issue in privatisation of hydropower projects was determining the real cost of such projects so as to ensure that major risks of the private operator were covered, without allowing them to claim excessive and underserving costs (MoP, 1997). This raised the question of whether hydropower can at all be opened to the private sector, particularly under the cost-plus tariff route. However, the reforms continued to push for privatisation in hydropower.

Given its peculiar characteristics such as a high fixed cost, large social and environmental impacts on account of huge land requirements, and uncertainty regarding ultimate cost and generation, the 2008 Hydropower Policy specifically exempts large hydropower from the requirement of competitive bidding for tariff discovery. Instead, it allows regulatory commissions to determine tariff of private hydropower projects on a cost-plus basis. To qualify for this, the projects have to fulfil certain conditions such as undertaking international competitive bidding for equipment purchases, entering into a long term power purchase contract for at least 60% of the saleable energy, and so on (GoI, 1998). However, a cost-plus tariff based approach has meant significant cost overruns and ever-increasing tariffs. To make matters worse, many projects have consistently failed to generate at the levels assumed during construction. The sector remains largely public owned, and the few projects developed by the private sector have raised more questions and concerns than providing alternatives.

Renewable Energy

Renewable energy entered national policy discourse as a means to enhancing India's energy security, which was sharply undermined from the oil shocks of the 1970s. Renewable energy technologies, particularly for power generation, were still mostly in the laboratory stage and the primary emphasis during the 80's was on research and demonstration. It was not until the separate Ministry of Non-conventional energy sources (MNES), formed in 1992, issued a policy advisory to states to price renewable electricity at a minimum of ₹ 2.25/kWh (with 1994–95 as the base year) with an annual escalation of 5% for 10 years that the sector really began its first phase of growth. This price certainty along with benefits such as accelerated depreciation, 100% Foregin Direct Investment (FDI), energy banking and concessional third party sale resulted in significant growth in wind, biomass and small hydropower generation capacity. Nearly all of the 3.4 GW of RE capacity installed by 2002 was set up with private investments with negligible state ownership in contrast to the thermal, hydropower, and nuclear sectors.

Given that the direct costs of renewables are higher than conventional power[12], the primary policy emphasis has always been on cost reduction on the one hand, and protecting the growth of the renewable energy sector on the other hand, through various policy-regulatory instruments as long as there is a lack of a level playing field for renewables (i.e. the cost of socio-environmental externalities of conventional power is not internalised). Electricity Act has many provisions to encourage the use of renewable energy. Two important reforms which initiated a second growth phase in the sector (from 2003 to 2010) were technology-specific preferential tariffs (i.e. cost-plus feed-in-tariffs) along with minimum renewable purchase targets for all obligated entities such as DISCOMs, open access and captive consumers. While there have been failures in strict compliance with such minimum purchase obligations, states with good wind potential like Tamil Nadu and Maharashtra were the first ones to exploit it.

The biggest push for renewables was the launch of the National Solar Mission in 2009 and the change in the solar pricing methodology from regulated feed-in-tariffs to those discovered through competitive bidding. Competitive bidding in photovoltaic (PV) solar has been a success story so far. It has witnessed healthy competition with a significant number of players and rapid reduction in the

12. However, this situation is fast changing with latest solar prices being comparable or even lower than those from new coal power plants (CERC, 2016).

discovered tariffs. The solar tariffs discovered in 2010 were more than ₹ 12 per unit but have fallen to about ₹ 4.5 per unit in the recent rounds of 2016. So far, there has been no major litigation for post-facto contract revision. However, given the purchase obligations and the largely vertically integrated nature of the wind industry, it's aversion to competitive price discovery is a matter of concern.

Distribution sector

After the enactment of the Electricity Act, 2003 national policies and plans on electricity were introduced by the central government. This included the National Electricity Policy, Tariff Policy, Rural Electrification Policy and National Electricity Plan. These policies and plans envisaged universal access of electricity by 2012, and electricity tariff fixed on commercial principles to encourage competition and efficiency. A massive rural electrification programme with household electrification focus was initiated by the central government.

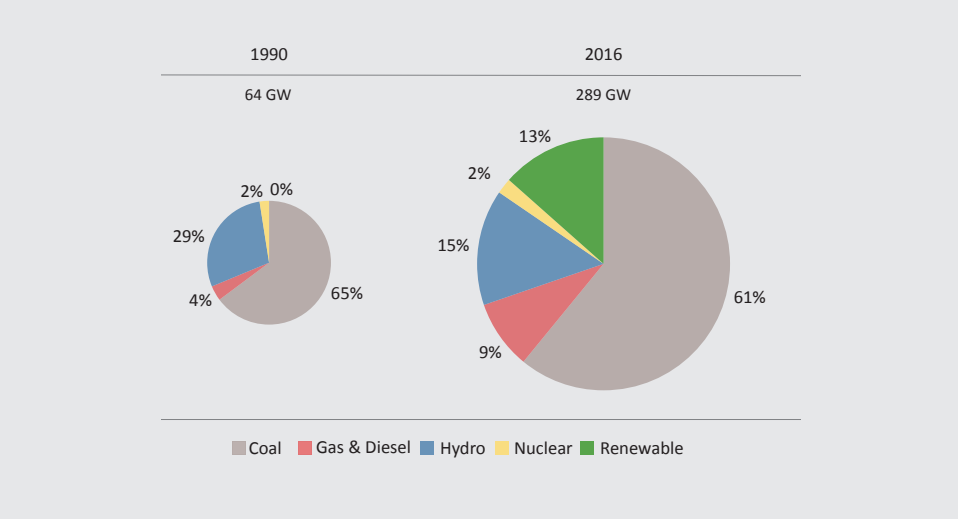
Open access, i.e. non-discriminatory access to use the network, was made mandatory in a phased manner in transmission and distribution. Any transmission or distribution company had to make its infrastructure available at a charge to anyone who wanted to use it to transfer electricity. Open access made it easier for power generators to sell power to consumers across the country. It also helped big consumers to access power from their generator of choice. Power trading, which means purchase and sale of electricity, was recognised as a separate activity. Many companies took up power trading activity and power exchanges, transparent platforms for power trading, were set up.

All SEBs were to be unbundled and electricity regulatory commissions set up in states. The E Act elaborated the role of the Electricity Regulatory Commission (ERC) at the central and state levels. The central ERC was to issue licenses and fix tariff for all multi-state operations. The state ERC had the responsibility of monitoring the state companies, fixing consumer tariff and approving investments. The E Act mandated the SERCs to increase transparency in the sector operation and provide opportunity for public participation. As a pro-consumer measure, the E Act made it mandatory for Distribution Companies to notify standards of performance and set up consumer grievance redressal forums. The E Act had strict provisions to reduce power theft. An Appellate Tribunal for Electricity (ATE) was set up for appeal against decisions of the ERCs.

1.2.4 Current status and key trends

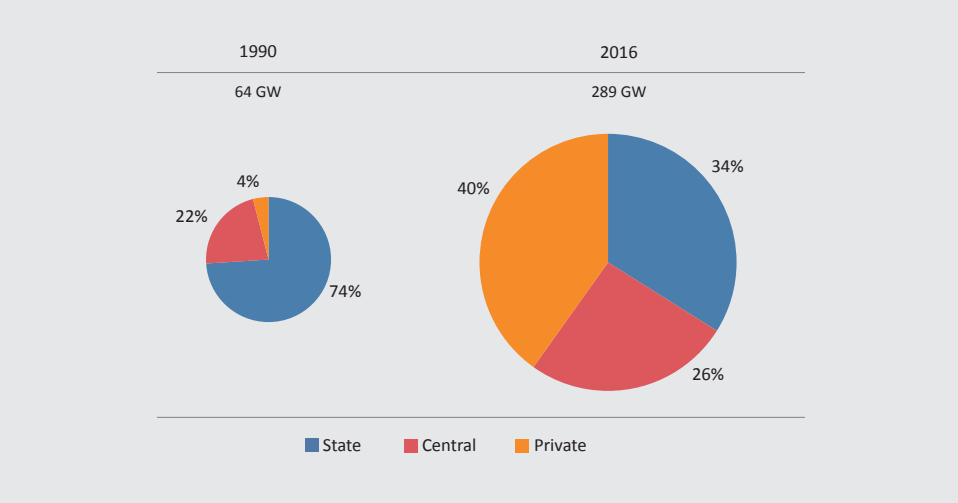
Several changes have taken place in the Indian electricity sector in the last two and a half decades, which are not easy to capture in one place. Figure 1.2 to Figure 1.6 provide a macro picture, capturing the changes in generation fuel mix, generation ownership and consumer mix from 1990 to 2016.

Figure 1.2: Generation capacity-fuel mix 1990 and 2016



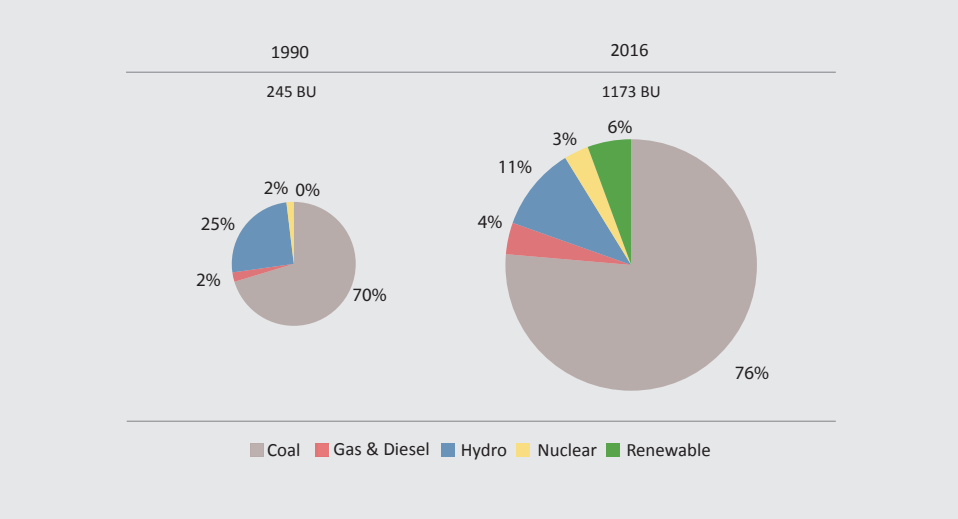
Source: (CEA, 2015) (CEA, 2016).

Figure 1.3: Generation capacity-ownership mix 1990 and 2016



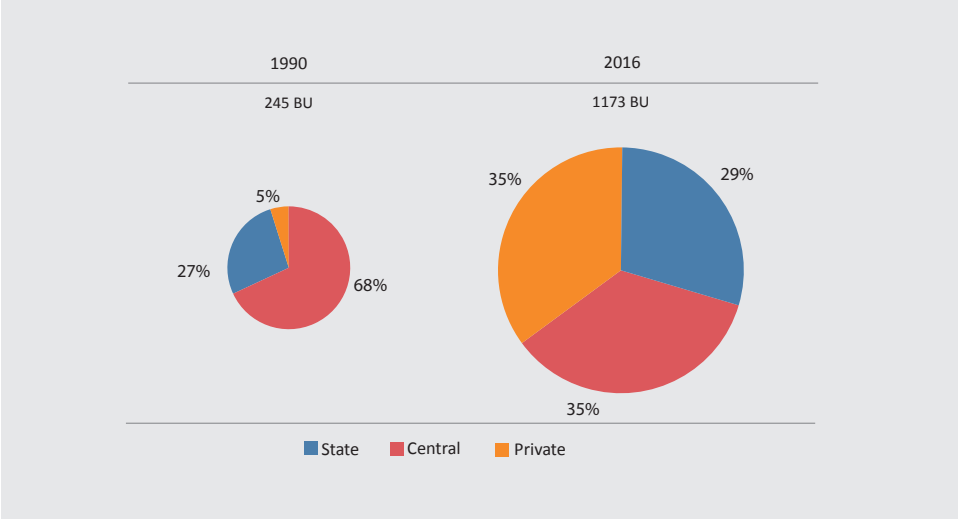
Source: (CEA, 2015; CEA, 2016; World Bank, 1993; PEG, 2016).

Figure 1.4: Generation-fuel mix 1990 and 2016



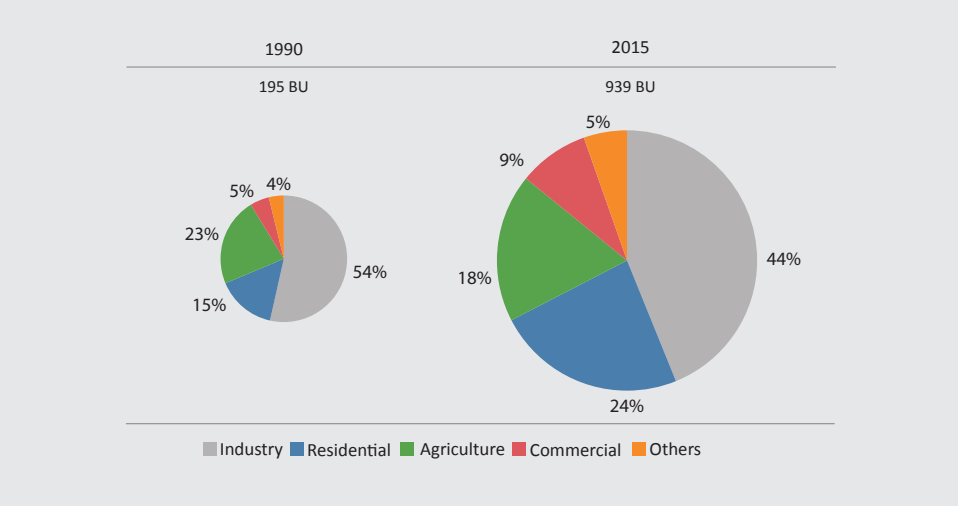
Source: (CEA, 2015; CEA, 2016; Planning Commission, 1990; PEG, 2016).

Figure 1.5: Generation-ownership mix 1990 and 2016



Source: (CEA, 2015; CEA, 2016; Planning Commission, 1990; PEG, 2016).

Figure 1.6: Electricity consumption mix 1990 and 2015



Source: (CEA, 2015).

Figure 1.2 shows percentage fuel mix in generation capacity in 1990 and 2016. The installed capacity increased from 64 GW in 1990 to 289 GW in 2016 — an increase of 4.5 times. Coal predominance has not changed over the years, but contribution of hydropower has reduced, that of gas has marginally increased, that of nuclear has remained the same, while that of renewables has increased considerably. Renewable capacity has crossed the hydropower capacity in April 2016 and will further increase due to the initiative to reach 175 GW renewable capacity by 2022.

Figure 1.3 shows percentage ownership of generation capacity. State governments were the major owners in 1990, whereas in 2016, private sector owned most of the generation capacity. Role of the central sector has remained same. Renewable capacity is almost completely in the private sector. This trend of increasing the role of the private sector is likely to continue.

Figure 1.4 shows the percentage fuel mix in electricity generation in Billion Units (BU) in 1990 and 2016. Coal predominance has increased, hydropower percentage reduced, and contribution of renewables, gas and nuclear power increased. From Figure 1.2 and Figure 1.4, it can be seen that the percentage contribution of coal-based generation is higher than its percentage share in capacity. For hydropower, gas and renewables, the percentage generation is lower than percentage capacity, since they generate electricity only when water, wind or sunlight is available.

Figure 1.5 shows the percentage ownership mix in generation in 1990 and 2016. Similar to the trends in capacity, the contribution of the state sector has reduced, that of the central sector has marginally increased, and that of the private sector has increased significantly.

Figure 1.6 shows percentage electricity consumption mix. Electricity consumption increased from 195 billion units in 1990 to 939 billion units in 2015 — an increase of 4.8 times.[13] Share of consumption by industry and agriculture consumers has reduced, whereas that of residential and commercial consumers has increased. This is a reflection of the growth of the service sector, growing middle class households, increasing household electrification and improved energy efficiency in the industrial sector.

The per-capita electricity consumption increased from 329 units/year in 1990 to 1075 units/year in 2016 — an increase by 3.26 times (CEA, 2016a, p. 11; CEA, 2015, p. 6).[14] It is another matter that India's per-capita consumption is still one-third the world average. Among households with electricity access, the average per capita per year residential electricity consumption is about 200 units/year as against a world average of over 900 units/year.

There was significant progress in providing electricity connections, especially during the last decade. Village electrification increased from 81% in 1990 to 98% in 2016, and household electrification went up from 42% in 1990 to 67% in 2011.[15] But with nearly 5.5 - 5.8 crores non-electrified households in 2016, the household connection challenge continues to be daunting and the quality of electricity supply to rural areas still remains poor. The on-going 'Power for All' program proposes to provide 24 x 7 power to all by 2019.

Even after so much attention and many massive programmes, Transmission and Distribution losses, one of the key indicators of efficiency, remained more or less same — these were 23% in 1990, went up to 34% in 2002 (largely due to better

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13. Electricity consumption data for 2016 was not available at the time of writing. Our approximate extrapolation indicates that consumption in 2016 will be around 1000 BU, with nearly a similar percentage share of different consumer categories.

14. Per-capita consumption as reported by CEA, is the figure arrived at by dividing the total electricity generation in a year by the mid-year population.

15. This is certainly an improvement, but as described in Chapter 5, there are issues about inadequacies in the definition of village electrification and validity of the household electrification data. Household electrification data is from Census 2011. As per the recent government reports, there has been further improvement and the rural household electrification could be 71% (REC, 2016).

reporting after the introduction of regulatory commissions), and is now reported to be 21%.[16] Even though financial turnaround was one of the key objectives of reforms, financial losses of Distribution Companies kept increasing and there have been many central government supported bail-out plans, the latest being the Ujwal Discom Assurance Yojana (UDAY), rolled out in late 2015.

For many years after independence, tariff for industry and agriculture consumers were kept low compared to that for commercial and domestic consumers to encourage industry and agriculture. As late as 1976, the industry and agriculture tariffs were 25% and 15% lower than the average cost of supply respectively, when domestic and commercial tariffs were 40% and 85% higher than the average cost of supply respectively. In 1997, during the initial years of reform, domestic and agriculture tariffs were considerably low - only 50% and 10% of the average cost of supply. Once the reforms started, tariff of domestic and agriculture consumers went up, but still remained below the average cost of supply. In 2013, domestic and agriculture tariffs were 50% and 30% of the average cost of supply. Commercial was 30% higher and the industry tariff nearly equal to the average cost of supply. Some experts believe that India has among the highest energy prices in the world, on a purchasing-power parity basis (Sethi, 2016). This indicates that improving the efficiency of the sector is more crucial than increasing tariffs.

It is to be noted that electricity shortages have reduced. There were severe shortages in 1990s, with 16.66% peak shortage and 7.92% energy shortage. From 2014, shortage has been reducing. The energy shortage was 2.1% while the peak shortage was 3.1% in 2016. The Central Electricity Authority has projected that there will be power surplus for the first time in 2017, with 1.1% energy surplus and 3.1% peak surplus (CEA, 2016b). This is indeed a positive development, though there are many questions which remain to be answered. The power situation is different in different states, with nearly half the states having shortage. The CEA largely uses historical trends to estimate demand and does not account for latent demand. The availability of power does not automatically lead to increase in consumption if the power is costly. In fact, it is already leading to backing down of some generation, with distribution companies having to pay the capacity charges, leading to higher consumer tariff.

16. Supply to agriculture pumps, which accounts for 20%–30% of total sales in most states, continues to be largely unmetered, raising concerns regarding the veracity of the loss figures and possible camouflaging of losses as agricultural consumption.

Efforts to introduce major changes to the Electricity Act 2003 started in 2014. A draft was introduced in the Lok Sabha in 2014, but as of November 2016, it has still not been passed by both houses of the Parliament. The major amendments proposed are to provide the choice of power supplier to even small consumers, thus bringing competition to the retail level. Amendments suggested include creation of separate electricity supply companies (called separation of distribution carriage and content), further promotion of open access, increased encouragement of renewables, and strengthening provisions for regular tariff revisions. Anticipating greater role of competition and multiplicity of supply options, the amendment aims at introducing ancillary services, spinning reserves and enforcing greater discipline in grid management. It also proposes major changes in the selection process of the regulatory commission members and chairperson, term of office, etc., while also putting in place mechanisms for performance review of the commissions (PEG, 2015).

Tariff Policy was notified by the Indian government in 2006, which laid down the framework for fixing tariff for generation, transmission, distribution and consumers. There have been minor amendments to the policy and a new amended Tariff Policy was brought out in 2016. This policy has provisions to promote renewable energy, to pass the impact of change in the cost of coal to the consumer, to facilitate 24 x 7 power and to introduce a time-of-the-day tariff.

1.2.5 Major lessons from the electricity sector reforms

The previous sections have presented a brief overview of the major reforms with the various segments of the electricity sector. This section summaries those developments and briefly highlights the latest developments and challenges. It covers thermal and hydropower generation, renewable energy and distribution sector.

Thermal generation

The earliest power sector reforms were centred almost exclusively on generation, and in the case of both thermal and hydropower, the focus was on increasing the installed capacity. Even here, the focus was essentially on getting the private sector to build new generation capacity. This was because the problem was diagnosed as one of lack of resources, with the government to invest in infrastructure creation. To encourage private sector participation, a host of incentives were provided and simultaneously, measures were put in place to cut risks for the private players. In spite of this, as discussed earlier, the results of the implementation of the IPP policy were at best, abysmal.

The most crucial distinction between the IPP era of the 1990s and the post Electricity Act 2003 period is that capacity addition actually happened on the ground under the latter. Part of this success can be attributed to the formal requirement of contracting power under a transparent bidding process. Through its flagship Ultra Mega Power Projects (UMPP) policy, the government tried to walk its talk of offering better prepared projects sites, faster clearances and at times providing fuel through captive block allocation. It all began with a flying start as the rates discovered in the initial rounds of bidding for coal based thermal projects were much lower than those determined by the regulatory commissions for similar projects under the 'cost-plus'[17] tariff regime. The rates discovered for the UMPP projects were even lower and were expected to set new benchmarks for efficient power procurement. It was felt that finally the sector is poised to benefit from the efficiency gains that competition is believed to unleash. Alas, the optimism was short lived.

The first hiccups were in the form of a number of players participating in the market. Notably, very few international players participated in the bids, and a large part of the capacity being developed is concentrated amongst a few players. Three out of the four UMPP contracts were won by Reliance Power, while the remaining one was won by Tata Power Ltd. However, major issues emerged only after the projects started approaching the actual generation date. From 2012 onwards, many projects, including the only two UMPPs which ultimately materialised[18], initiated litigation seeking a post-facto revision of the quoted tariff. Increase in imported coal prices, lack of domestic coal availability, or an inability to develop a given coal block were the primary reasons cited for such revision. The bidding framework allowed the project developers to pass through various risks pertaining to fuel and capital costs transparently at the time of bidding. However, some projects quoted a fixed tariff for 25 years, while others chose to only partially pass through the fuel price variation risks. In most cases, the fuel price related assumptions made by the winning bids were devoid of any contractual basis, as most of them did not have any firm fuel supply contracts when the bids were submitted. This makes

17. Cost-plus tariff is the tariff for electricity generation decided by the Regulatory Commission based on information submitted by the company on project cost and fixed returns. In most cases, all claimed costs are approved, often leading to the danger of cost padding.

18. Out of the four UMPPs, only the Reliance owned Sasan UMPP in Madhya Pradesh and the Tata owned UMPP in Mundra were actually constructed and are generating power. The construction of the other two Reliance UMPPs, namely Tilaiya in Jharkhand and Krishnapatnam in Andhra Pradesh, was not completed and following litigation the contracts for both these projects have been terminated.

one wonder what, if any, due-diligence was undertaken by the lending agencies, which funded these projects without much regard for the basic aspects of project viability.

As this capacity started nearing generation, the already stagnated domestic coal production faced the strain of increased demand. The chaos that ensued created an atmosphere of uncertainty, as a result of which, the tariffs discovered in the subsequent rounds of bidding were higher than the regulated cost-plus projects. Eventually, the bidding guidelines itself were modified to make fuel cost a pass through element, thus defeating the very purpose of introducing efficiency through competition.

Unlike coal, many of the gas-based projects for which MoUs were signed during the 1990s were based on imported fuel and hence were quite expensive. Most of them never materialised and the few that did were stranded for want of fuel or buyers for such expensive power. Thereafter, claims regarding domestic gas discoveries in the Krishna Godavari basin renewed interests in gas-based generation. Based on these gas production claims, some states like Andhra Pradesh added significant new gas-based capacity. However, the domestic gas production never took off in a manner that was anticipated and yet again, the gas-based capacity remained stranded. In 2016, more than half of the total gas-based installed capacity of 24 GW is idle, and the remaining half is running at a load factor of around 30%. To utilise some of these plants, the government in 2015 introduced a subsidy scheme to make generation based on imported gas viable. While it helped a few projects to generate some power, the fact remains that most of the gas-based capacity is largely unutilised, blocking crucial resources which could have been put to better public use. Further, the states that had relied on this capacity had to face shortages and are forced to find alternate options.

Tariff of many regulated and newly commissioned thermal power plants are higher or comparable to the newly discovered solar rates. Thermal is able to compete with solar only on account of its lack of variability. However, given the ease and modularity of setting up solar installations, the downward cost trajectory of storage options, policy and regulatory initiatives such as net-metering and partial waving off of cross-subsidy surcharge for renewable based open access, the days of thermal generation as the mainstay of the power sector are numbered.

Hydropower

The progress of the hydropower sector in the last 25 years shows that the reforms failed to deliver on the primary aim of bringing in private investment. In spite of all the incentives, the private sector added only 12.5% of the 24,000 MW hydropower capacity added between 1991 and 2016. Even in terms of resources, it is estimated that the private sector will have deployed around 15% to 20% of the resources, with the substantial portion derived from public sources. Even this limited contribution may not fully materialise, as a large number of on-going private projects as well as those in the pipeline are facing serious issues of inability to mobilise finances and slow progress in construction. Out of a total capacity of 4555 MW under construction, close to 4000 MW is facing serious problems as reported by the CEA, with fund constraints faced by developers affecting 2200 MW or 50% of the private capacity under construction.

It is ironic that even as privatisation, competition and operation of market forces were supposed to be the core strengths of the reforms, in case of hydropower, true competition and market operation was never put in place. Tariffs from hydropower projects were determined through a cost-plus approach, making them vulnerable to cost-padding. One of the most important inputs, namely land, was acquired not through any market operations at market prices, but by compulsory acquisition using the Land Acquisition Act 1894, at very low prices. Sale of the 'product', that is, electricity, was also divorced from the market. Power off-take and payments were often guaranteed with state/sovereign counter guarantees or escrow arrangements.

One of the biggest omissions of the reforms process is that it has done little to address and improve the process of dealing with the social and environmental impacts of hydropower projects, even though these have been identified as having huge impacts on local communities and the ecology, as well as being major concerns in implementing hydropower projects. As a result, thousands have continued to be displaced without any meaningful resettlement, and river valleys continued to suffer great environmental damage. Impacts of climate change are another area that the reforms have completely ignored. In particular, the risks that climate change impacts like extreme rainfall events create for the cascades of dams being built in the Himalayas, and the danger that these projects will aggravate the impacts of climate change in the Himalayan region, both have been ignored. In the Himalayas, where much of new hydropower is to come, climate change is likely to aggravate the already serious issues like landslides, erosion, seismicity, floods and Glacial Lake Outburst Floods (GLOFs).

Given the experience so far, pushing hydropower without addressing the social and environmental impacts is going to be disastrous. At the same time, reforms focussing only on the financial elements, and that too narrowly on privatisation, without looking at aspects like competition are likely to continue to fail. Indeed, a thorough review of the desirability of encouraging and incentivising privatisation in the hydropower sector is warranted. Overall, before deciding on desirability of specific projects which often have high social and environmental costs, likely contribution of the proposed projects to meet peaking load needs to be realistically assessed.

Unfortunately, though the evidence shows yawning gaps between the promise and performance of the reforms in the hydropower sector, steps being planned for the future indicate a policy of "more of the same", a sure recipe for failure.

Renewable energy

The exponential growth in the solar sector has pushed up the renewable capacity to 45 GW in the country as of July 2016, and the government has plans to take it further to 175 GW in 2022. This is likely to result in a paradigm shift in the entire sector from planning, pricing, grid operation to consumer tariffs. From the perspective of renewable grid integration, regulatory initiatives to mandate forecasting and scheduling of wind and solar power started in 2010, but have only begun to be operationalised in 2016 after several changes in the rules. Since environmental clearance requirements have been completely waived for solar, wind and biomass plants, there remains no mechanism to understand and possibly prevent any adverse impacts on the local natural environment and irregularities in land transactions and compensation.

The biggest challenge for the policy-regulatory establishment going forward is to balance the growth of renewables without putting severe strain on the distribution companies' finances. Continuation of separate solar and non-solar categories for renewable purchase obligations when solar prices are going below that of wind is a case in point for the need of fast policy response to the changing sector. Renewables have surely entered a phase where they can begin to compete with conventional generation, and the electricity sector needs to quickly get its act together to allow for a smooth transition by integrating renewable energy within the overall electricity sector planning and operation. Finally, further incentivising cost reduction through competition and government facilitation (like in the case of solar photovoltaics) is still strongly needed, and the government seems to have taken the first step in this regard for wind power recently.

Distribution sector

The distribution sector has seen many changes in the last two decades as elaborated in Section 1.2. But these changes have not resulted in a financially healthy sector capable of providing quality affordable access to all.

Though many states restructured the State Electricity Boards by unbundling, the newly formed distribution companies do not act as separate corporate entities, with most companies being managed by state power secretaries and with no independent directors. Lack of capacity and fleeting tenures for senior leadership contribute to the managerial issues. Resistance to regular tariff revisions and metering continue in many states. With slow progress in metering, the veracity of claims in many states of significant reduction in the Aggregate Technical and Commercial (AT&C) losses can be questioned. The Odisha experiment with privatisation has recently ended with the revocation or termination of all awarded licenses. This state, with largely poor rural consumers, needed state support and network investment to ensure quality power supply. Therefore, it was a big challenge for private players, and they failed. Privatisation in Delhi was different. There was transitional support from the state government and clear performance targets. The private companies were largely successful in reducing AT&C losses and improving service quality. However due to poor power procurement planning and ineffective regulatory oversight, financial losses continue to balloon in Delhi. Many distribution companies have also contracted past of their business in urban areas to franchisees. The initial experience with these franchisees has been fraught with issues with contractual issues, delays in implementation, persistence of high losses and lack of timely payments.

A major contributor to the accumulating financial losses of distribution companies is issues with power procurement planning as power purchase cost constitutes 75–80% of the total cost in distribution. There are several issues with demand estimation with most exercises overestimating energy requirement and not accounting for potential sales migration, energy efficiency efforts. DISCOMs have procured long term capacity much in excess of their estimated demand and most of this new capacity is expensive. Over-procurement of capacity and lack of scientific demand estimation has resulted in many generating plants not being run. As per contract, DISCOMs pay these idle plants for the fixed cost incurred. In turn consumers have to bear the additional cost of the inefficiency of DISCOMs.

Increasing costs and issues with revenue recovery has resulted in precarious financial position of distribution companies. Since the restructuring of SEBs, there have

been three major bailouts to address this issue of mounting liabilities. However, in each case, due to the 'open tap' of bank lending and lack of adequate incentives and penalties for compliance to conditions, DISCOMs continued to accumulate losses. The last of the bailouts, UDAY (Ujwal DISCOM Assurance Yojana) launched in 2015 entails that signatory states take over past and future debt in a progressive manner. This could incentivise state governments to curb unsustainable practices. It is yet to be seen if DISCOMs are able to steer clear from further borrowing and ensure that UDAY is the last bailout.

Universal access to electricity has seen slow progress over the years despite ambitious commitments. Even though large investments (with the focus of electrifying pump sets) over the years had resulted in the grid reaching most villages, a significant proportion of households continue to be non-electrified. The 2005 Rajiv Gandhi rural electrification program as well as the recent 24 x 7 Power for All programme are welcome initiatives with significant investment by the national government. Even so, there are doubts if the target of universal access and 24 x 7 supply will be met by 2019.

Although relatively young, the Electricity Regulatory Commissions (ERCs) have gone a long way in ensuring public accountability, instilling transparent decision-making processes, and encouraging public participation. However, their autonomy has also been severely constrained as their appointments are made by the state governments. Delays in appointments and lack of regulatory staff also limit effectiveness of these institutions. Most ERCs often limit their role to tariff determination. They do not often succeed in ensuring compliance by utilities or in reviewing the implementation of large scale programmes. ERCs are also not accessible to small consumers and seldom take proactive efforts to encourage informed participation. With all its flaws, ERCs are important institutions and the democratic spaces made available with their presence needs to be expanded. With increased role of market operations in future reform efforts, the need for effective regulators will be paramount.

With increasing penetration of renewables and market operation, distribution companies have to change from the traditional mode of operation. Phased transition to a new business model requires detailed planning. It is not easy to make suggestions for this transition, but we have provided some ideas in Chapter 5. Small and large consumers need to be treated in a different fashion. Small consumers should be given tariff certainty and adequate affordable power for productive

activities. Migration of large consumers to alternate supply options has to be properly managed in a phased manner. Distribution Company should prepare long term business plan with a view to improve efficiency of operation. Financial support required during the transition period should be linked to efficiency improvement.

1.3 Related sectors — coal and gas

Coal fuels most of the country's power generation. It also has a significant role in improving access to electricity, as it is likely to remain the cheapest source for electricity generation in the short term. Natural gas supports only about 9% of total installed capacity currently due to various supply constraints, but is expected to play an important role in the future. Official numbers suggest that India has significant coal resources, though of poor quality, while being generally poor in other hydrocarbons. India's domestic reserves of oil and gas are limited and these are reflected in rapidly growing imports with India's import dependence reaching about 33% in recent years. Like thermal generation and large hydropower, coal and gas are also capital intensive sectors with long gestation periods, high production risks and significant impacts on other scarce resources such as land, water and forests. Besides fuelling the country's power sector, these fuels are crucial sectors in their own right and are essential to meet the country's overall energy demand. However, our analysis in this book will be limited to viewing them as crucial linkages for the power sector.

1.3.1 Coal

The coal sector in India was nationalised in the 1970s to improve mining practices, protect labour interests, increase efficiency, and hence production. Following this, the public sector coal mining behemoth Coal India Ltd. (CIL) was born, and India's coal production gradually increased from 80 million tonnes per annum (MTPA) in 1972–73 to 259 MTPA in 1992–93. With the opening up of the economy in the early 1990s and the proposal to open up power production, it was felt that the demand for coal would rapidly outstrip CIL production. However, instead of opening up the coal sector for commercial mining, companies engaged in power generation were selectively allowed to mine coal for their captive use since 1993.

Today CIL is one the largest coal mining companies in the world and accounts for around 80% of the domestic coal production. Apart from CIL and its subsidiaries, the Singareni Collieries Company Limited (SCCL) is the only other coal mining company which is jointly owned by the Government of Telangana

and the Government of India, and which accounts for about 10% of the total coal production. The remaining 10 odd percent comes from captive blocks. In spite of the sector being dominated by two public sector monopolies, in a curious move, coal pricing was completely deregulated in 2000. This allowed CIL and SCCL to set prices without any independent scrutiny for prudence.

As of the early 2000s, a domestic coal consumer had two possible routes to obtaining the coal. The first was the linkage route where a linkage committee would allocate coal to the desirous consumers, and the second was by obtaining a coal mine for captive use awarded by the central government. In both methods of allocation, the number of consumers seeking coal was far higher than the resources available. However, there was no policy to govern and regulate these allocations and as a result of this, few, especially small consumers, could not access coal at reasonable prices. These consumers, such as one Ashoka Smokeless, approached the Supreme Court regarding this issue, and the Court directed the government to introduce a policy for coal allocation. Following this, the government introduced the New Coal Distribution Policy in 2007 to allocate coal linkages. It needs to be noted that an allocation policy for coal was notified fifteen years after the opening up of the power generation and that too at the behest of the Supreme Court.

Given this context, three major policy initiatives related to coal allocation are reviewed in Chapter 6, *The Indian coal sector: A black past and a grey future*. The first is the New Coal Distribution Policy (NCDP) which was adopted in 2007. An analysis of this policy and its implementation shows that the policy was drafted very ambiguously. More than 40 GW of coal-based capacity was contracted between 2007 and 2011, a large part of which was dependent on domestic coal linkages. The ambiguities in the NCDP allowed excessive allocation of linkages by the concerned committee to both public and private sector power projects. Further, convenient interpretations of the NCDP were made by the power generators and their financiers who backed projects based on contractually vague letters of allocation. As the generation capacity started coming online, the country's power sector faced severe coal shortages in 2012–13. There are many on-going cases related to interpretations of the NCDP, with the possibility that electricity consumers may have to bear the costs of ambiguous policy drafting and aggressive bidding based on unrealistic assumptions.

The second policy reviewed concerns allocation of coal blocks for captive consumption to consumers from the power and other sectors roughly between

1993 and 2010. The story of the problems with these allocations has been covered extensively in the media and elsewhere under the name of the 'coal-gate' scam. It is a sorry tale of illegalities, irregularities and discretionary decision-making as was exposed in a report by the Comptroller and Auditor General and a couple of orders from the Supreme Court.

The third policy reviewed looks at the allocation of coal blocks under the revised regime of the Coal Mines (Special Provisions) Act in 2015, through allotments (to public sector companies) and auctions (to public and private sector companies). While these allocations addressed some infirmities of the earlier regime, they come with their own set of concerns. There are legal ambiguities regarding the method of selecting block beneficiaries and the method of land acquisition. Though the stated objective is to lower consumer tariffs, it is not clear how this would be achieved given the regulatory complexities surrounding its operationalisation. There are also concerns regarding the allocation criteria, viability of the bids, ability to monitor and enforce these contracts, and transparency of the entire allocation process. As of August 2016, these conclusions are validated by the lack of any significant production from the allocated blocks, almost no known reduction in electricity tariffs due to the blocks, many on-going court cases, and a rapid loss of interest in further rounds of block allocations — including for commercial mining by state companies — attempted by the Ministry of Coal.

In addition to these reforms, the chapter also looks at some issues that needed to be addressed but were ignored. These include the absence of any concerted initiatives to improve the efficiency and accountability of CIL, the lack of interest in setting up effective regulation and monitoring of the coal sector operations, and the continuing neglect of socio-environmental concerns and law and order issues around the coal sector. To summarise, it may be said that the reforms that were attempted in the coal sector suffer from many serious weaknesses, while many critical issues plaguing the sector continue to be neglected.

1.3.2 Natural gas

Oil and gas production was a relatively small private sector enterprise at the time of India's independence. Given the country's thrust towards industrial and public sector development, the Oil and Natural Gas Commission (later ONGC) and the Indian Oil Corporation (later IOC) were established in the 1950s to develop domestic exploration, production and distribution of oil and natural gas. By the early 1990s, there was significant growth in domestic production particularly due

to a prolific discovery off the western coast of India in the 1980s. Yet, due to the increasingly difficult exploration operations and due to some controversies in the late 1980s regarding improper reservoir management, it was felt that additional growth in exploration and production can only happen through application of more advanced practices, technology and expertise which required significant capital investment.

When reforms were introduced to liberalise the country's economy, all segments of the sector, i.e., exploration and production (upstream) as well as refining, marketing, transportation and distribution (downstream) segments were opened up for private investment. For natural gas, this was done through administering production sharing contracts (PSCs) with upstream players, and through natural gas pricing policies in the absence of a national gas market. These policies had a significant impact on the power sector.

Production sharing contracts under which the government receives a share of the profit, were operationalised through the New Exploration and Licensing Policy (NELP) introduced in 1999. Under NELP, acreages were granted to (public and private) companies based on a competitive bidding process.[19] Some early discoveries under the NELP process gave cause for optimism that India could rapidly ramp up domestic gas production. It also resulted in significant addition to gas-based power generation capacity. However, as of 2016, NELP contracts have not resulted in any significant sustained increase in domestic gas production, and in spite of international competitive bidding there are not many players.

Domestic natural gas production that peaked in 2010–11 dropped significantly thereafter. Figure 1.7 shows India's gas production since 1947–48. The peak production at 52 billion cubic meters (BCM) in 2010–11 and subsequent fall to 35.4 BCM in 2013–14 are due to the rise and fall of production under PSCs, predominantly NELP.

Chapter 7, *Natural gas: Running on empty* takes a critical look at the NELP regime and related gas pricing issues that have had a direct impact on the electricity sector. It is found that apart from not meeting production objectives, the regime has resulted in many controversies regarding profit sharing, reservoir management, pricing and lack of institutional capacity.

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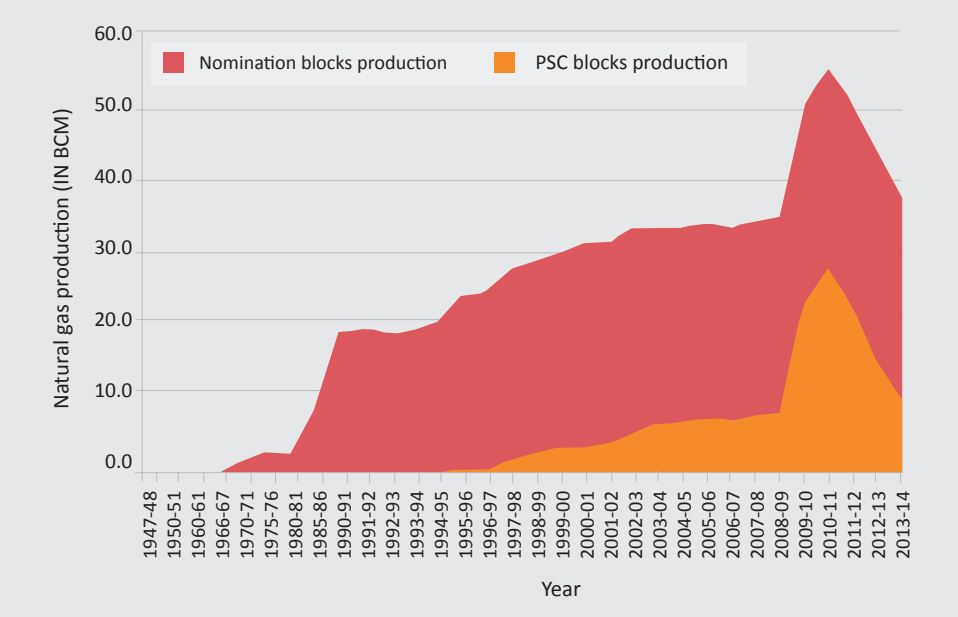
19. Even before NELP, there was a 'pre-NELP' phase where concessions were granted to the private sector, but the government still held a stake in these ventures.

Though not directly related to the electricity sector, the chapter also briefly looks at a few developments in the downstream oil-and-gas sector related to the formation and functioning of the Petroleum and Natural Gas Regulatory Board, as it has important lessons to offer in terms of how not to set up a regulatory institution.

Figure 1.7: India's natural gas production since independence



Source: Reproduced from (DGH, 2015, p. 30)[20].

1.4 Conclusions

In the last two and a half decades, there have been many changes in the sector. These are captured in Table 1.1. Those interested in a getting a bird's eye overview of the major changes in the electricity and related sectors in the past two and half decades of reforms could refer to the fold-out attached at the end of the book. Role of private players has increased, especially in electricity generation. From a 4% share in generation capacity in early 1990's, today private generation capacity is around 40% and is set to further increase. Capacity of renewable energy has grown from near zero in 1990s to about 13%, with wind power leading the show and solar power catching up rapidly.

20. PSC production refers to both NELP and pre-NELP blocks.

Table 1.1 Major changes during reform years

Area	Pre-reform, before 1990	Current status
Utility structure	Integrated SEB, with the functions of generation, transmission and distribution	Almost all SEBs unbundled into generation, transmission and distribution companies
Ownership pattern	Mostly with the government — state or central	High presence of private players in generation, moderate presence in distribution, growing presence in transmission
Policy	Policy making largely by state and central governments. Electricity considered a major development input	In policy making, influence of international funding agencies during the beginning of reforms, increasing role of central government and private players in subsequent years. Electricity moving towards a market commodity
Electricity regulation	Directly by the central and state governments	By regulatory commissions appointed by the government
Electricity markets	Not present	Increasing markets facilitated by open access, trading, merchant power plants and power exchanges. Competitive bidding, a market feature, has been introduced in many sectors.
Renewable energy	Very less, only small hydro, small pilots — not connected to grid	Significant capacity and ambitious plans
Energy efficiency	Small state level pilots	Large national initiatives , but impact not clear
Coal sector	Supply by government owned companies	Growing coal imports, moves towards privatisation, commercial mining, linkage auctions and regulation. Recent targets for reduction of imports.
Gas sector	Few government companies, moderate imports	High imports, few private companies also, regulation for downstream

The whole country is now connected to a national grid, though there are some bottlenecks, especially in the connections to the North-Eastern as well as Southern regions. The electricity market has started growing after 2003. There are two power exchanges in the country and many power traders. National rural electrification programs from 2005 have helped to increase rural access, though universal household access and quality of supply remains a big challenge. A national program (UDAY) has been rolled out to address the financial losses of distribution companies. A few national level programmes on end-use efficiency have been rolled out in the sectors of industry, building, lighting, fans and agriculture pumping.

Looking ahead, the proposed changes in the Electricity Act are expected to further increase the market operations. With falling prices and growing pressure due to climate and fuel availability challenges, renewable energy is set to play a bigger role, no more remaining in the margins. End use efficiency programmes will hopefully grow from strength to strength. The national grid is expected to be strengthened in capacity and operation to support the growing renewable capacity, market operations and inter-regional electricity flows. However, in light of the many challenges discussed further in this book, alas it remains doubtful that the programmes such as 24 x 7 Power for All by 2019, and UDAY designed to address the financial losses of distribution companies, will succeed in meeting their objectives.

Serious concerns about the financial viability of the sector persist, with the precarious situation of the electricity distribution utilities being well known. India's energy import dependence has been steadily rising and there are also increasing concerns around pollution resulting from the energy sector. Thus, the sector still faces many serious challenges in spite of over two and a half decades of reforms.

To sum up, India faces the difficult challenge of balancing its need to provide all its citizens with clean, modern energy services given the highly limited natural resources available, increasing social and environmental problems, and constraints imposed by climate change. Unfortunately, the country is inadequately prepared for dealing with this multi-dimensional challenge due to policy, planning and governance deficits. In addition to these challenges, technology is enabling large scale integration of renewables in a way that was difficult to imagine even a couple of years ago. While a greater role of renewables is a welcome change from the environment and sustainability point of view, in the short run, it can create serious challenges for the already precarious state of utility finances. The rapid rise of renewables coupled with a regulatory and policy regime that promotes open access at the cost of the utility's financial health may lead to more supply options for the rich and high-paying consumers. However, the rural consumers and the poor will have to continue to depend on the cash strapped distribution companies and thus, ultimately suffer the adverse consequences of such a transition. These fears become stronger in light of the proposed amendments to the Electricity Act 2003 which seek to institutionalise a greater choice for the large and high-paying consumers.

While the objective of moving to an energy sector that has a greater role for renewables, more choices for consumers and a fair and healthy competition

amongst various players is laudable and even inevitable in the long run, the critical but less debated issue is how such transition should enfold and who should bear its cost. This entails answering difficult questions such as:

- Given the worsening financial health of distribution companies, how can universalisation of electricity access and reasonable quality of supply be ensured?
- How much new thermal and large hydropower capacity should be built and considering that it will be largely underutilised; how should it be priced?
- In a market oriented sector, should the state-owned distribution companies be the suppliers of last resort for everyone and if so, how should they plan their power purchase?

Unfortunately, instead of dealing with these challenges head on, the present policy discourse is adopting the convenient approach of kicking the can down the road. Given this context and in light of these challenges, the analysis and critique presented in this book offers important lessons regarding past failures so that they can be avoided by implementing reforms in the future. It provides a comprehensive and critical evaluation of some of the crucial reform measures of the past and a few broad ideas for improving the sector policy and processes as we go forward. It is hoped that this will help the country to avoid the mistakes of the past and design policies and institutions that are more robust and can deal with the multiple challenges faced by the sector more effectively. It will also hopefully help in early identification of any negative trends and enable taking early corrective action. To paraphrase the famous saying by George Santayana, those who do not learn from history are condemned to repeat it.[21]

21. Santayana's original statement, from volume I of The Life of Reason, was "Those who cannot remember the past are condemned to repeat it."

2

Too good to be true: The story of thermal generation

"Though this be madness, there is method in it."

- William Shakespeare, Hamlet

2.1 Introduction and overview

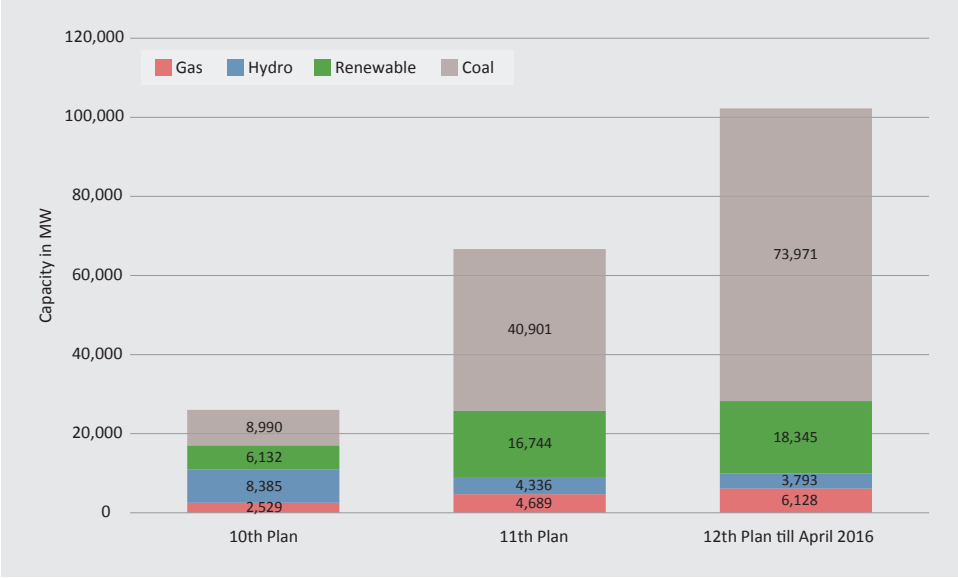
Coal based thermal generation has been the mainstay of the Indian electricity sector for a long time. Generation cost is one of the most crucial parameters for electricity tariff as it accounts for more than 70% of the cost of electricity supply. Being a relatively cheaper source, coal based generation is critical for meeting not just the base load power demand, but also for ensuring meaningful access to electricity. Much like the other infrastructure sectors, it is also a highly resource intensive sector with strong linkages with scarce natural resources such as land, water and fossil fuels, and is characterised by high investments and long gestation periods. It also has serious environmental and social impacts.

Thermal generation[1] capacity forms about 70% of the total installed capacity and contributes to about 80% of total generation. As of 30th November 2016 the installed thermal generation capacity is 213 gigawatts (GW) of which 188 GW is coal-fired and around 25 GW is gas-fired. Similarly, coal based capacity accounts for 76% of total power generation where gas along with diesel contributes roughly 4%. Installed thermal capacity has more than doubled from 92 GW in 2008 to about 210 GW in 2016 (CEA, 2016a). Figure 2.1 shows the source-wise break up of generation capacity addition since the 10th Plan.

1. Thermal generation can include coal, natural gas, nuclear, geothermal, solar thermal, diesel and waste incineration based generating stations. However, as far as this chapter is concerned, we are using the term to only imply coal and natural gas based thermal generation.

Natural gas is the second most used fossil fuel in power generation and fuels about 8% of India's installed capacity. However, since India only owns about 0.8% of the world's natural gas reserves (BP, 2016, p. 20) and given the limited exploration of its sedimentary basin thus far, India imports a significant amount (almost 40%) of its natural gas requirement. On account of the uncertainty of production and availability of domestic gas, increased dependence on gas based electricity production is likely to put pressure on balance of payments as well expose the sector to fuel supply uncertainties and hence is an unsuitable option, at least in the short and medium-term future. Imported gas based generation is also very expensive and hence not commercially viable. This perhaps is the reason why most of the thermal capacity added in the last two plan periods is largely coal based. Further, more than 80% of the thermal capacity that is in pipeline is also coal based (Dharmadhikary and Dixit 2011, 3).

Figure 2.1: Source-wise break up of capacity addition in the last three five-year plans



Source: (CEA 2015, p. 8, CEA 2016).

As discussed in Chapter 1, the generation sector was opened up in 1992 for private investments (GoI, 1992). The tariff was generally negotiated by the state government on behalf of the state electricity boards, and the project selection process was not transparent. Although many Memoranda of Understanding (MoU) were signed by various state governments, most of this capacity never materialised. The few projects that did were mired in controversies and imposed severe costs.

Following this, the Electricity Act, 2003[2] made generation (excluding nuclear and large hydropower), a de-licensed activity. Under the act, any company with the necessary resources and approvals and clearances (mainly for land acquisition and environment) could set up a generating plant anywhere in the country. The Act, applicable at present, allows industries to set up captive plants for their own consumption and also gives a certain set of (mostly large) consumers a choice to select the power supplier through what is called the 'open access' mechanism.[3] It also empowers regulatory commissions to grant licenses for trading of electricity. These legal and policy initiatives have had a deep impact on competition, supply availability and affordability, and distribution finances.

Given this background and significance, this chapter explores how the policy measures in the thermal sector have evolved over the past two decades and their implications for capacity addition and efficiency and affordability of generation.

2.2 Opening up of the sector and the Independent Power Producers (IPP) policy 1992

Based on the 1992 IPP policy, the generation sector was opened up for private and especially foreign investments, following which a large number of Memoranda of Understanding (MoUs) were signed. Celebrating the success of the policy, the Economic Survey of 1994–95 states: "The response to the new power policy has been overwhelming. So far 138 new proposals for capacity addition by private enterprises of 58,745 MW, with an approximate investment of more than ₹ 2,19,927 crores, have been received. 41 are from foreign investors including NRIs and joint ventures. 13 proposals have already been cleared by the government from the foreign investment angle." (GoI, 1995, p. 141)

Interestingly though, in the same year, the response of the Ministry of Power (MoP) to the queries raised in this regard by the Parliamentary Standing Committee on

2. An amendment to the Act was published in December 2014. The Parliamentary Standing Committee on energy has submitted its report on the proposed changes, though the Parliament is yet to pass the bill. The amendment proposes carriage and content separation, i.e. segregation of wires and the supply business for further enabling open access, competition and markets. A detailed commentary on the proposed changes and its implications for the sector is available at prayaspune.org/peg/publications/item/293.

3. Under Section 42 of the Electricity Act 2003, such a choice is presently given to consumers with a connected load of 1 MW or more. Subject to the terms and conditions for open access notified by the respective state commission, any eligible consumer can opt to choose a supplier other than the distribution company designated to supply in its area of operation.

energy is quite different. The MoP states on record that it had knowledge of about 137 projects for which MoUs were *estimated* to be signed. Out of this 137 projects, concrete information was available for only 83 proposals and even for these 83 proposals, validity of the MoUs could not be verified. From the introduction of the policy in 1992 till 1995, not even one of these 137 projects had achieved financial closure (Standing Committee on Energy, 1995–96, p. 16).

This status never changed much as there has never been any official data published by the central or state governments documenting the details of all the MoU projects such as capacity, tariff, fuel sources, the date of signing of the MoU, and the scheduled date of commercial operation. In spite of the frenzied response in the beginning, soon there was considerable doubt regarding feasibility and whether any of these projects would actually be commissioned.

2.2.1 Counter guarantees and escrow arrangements

In order to insulate the IPP from payment default risks of the SEB, the central government issued counter guarantees. Such guarantees were limited for a special category of projects called fast-track projects and actual agreements were signed only for Enron's Dabhol Power Project in Maharashtra and AES Transpower's Ib Valley Project in Odisha. The counter guarantee obligated the GoI to make payment to the IPP in case of default by the SEB. The liability of the GoI was limited to ₹ 1500 crores per year, and even in the case of termination of the PPA by the IPP, the GoI would be liable for clearing outstanding foreign debt. It is interesting to note that upon an enquiry by the Parliamentary Standing Committee on energy regarding the need for such counter guarantees, the Ministry of Power stated that these were sought by the investors and lending institutions because in the absence of any credit rating mechanism for the SEBs, private investors were finding it difficult to finance their projects. The ministry however could not submit any documentary evidence specifically asking for such a guarantee (Standing Committee on Energy, 1995–96, pp. 41, 42).

As an alternative to guarantees, escrow arrangements were suggested as a measure for protecting the IPPs from payment default risks and to ensure speedy financial closure (PEG, 2001a, p. 5). Under an escrow arrangement, the revenue collection from a certain area or zone of the SEB is kept in a separate escrow account and the concerned IPP is given the first right over it. In case of a payment default by the SEB, the IPP can recover its dues from the escrow account. In this regard, Madhya Pradesh is a glaring example of how the states were eager to promote IPPs at any

cost. To attract private investments, the MP government declared that it had an escrowable capacity of 5339 MW. However, when the state SEB appointed CRISIL, a credit rating agency, to study this issue, it was found that the real escrowable capacity was only around 2561 MW, which was less than half of what the government had claimed. Within a short span of around a year, in its revised study, CRISIL further reduced the escrowable capacity to around 900 MW which was 35% of the reduced capacity declared earlier.

2.2.2 Fast-track projects

In order to demonstrate the potential of the IPP policy, the government declared eight chosen IPPs as 'fast track projects'. It was hoped that showcasing the success of these projects would help to attract more investment, which was the primary objective behind opening up the sector. These projects were approved by the Cabinet Committee on Foreign Investments (Standing Committee on Energy, 1995–96, p. 26) and by the Central Electricity Authority (CEA). Table 2.1 shows the list of these projects.

Table 2.1: List and status of the eight 'fast-track' IPP projects

State	Project Name	Fuel	Capacity in MW	Developers / major share holders
Andhra Pradesh	Jegurupadu (CCGT)	Gas	235	GVK Industries, USA
Andhra Pradesh	Godavari (CCGT)	Gas	208	Spectrum Power
Andhra Pradesh	Vishakapatnam	Coal	1040	Hinduja National Power
Karnataka	Mangalore	Coal	1000	Cogentrix, China Light and Power
Maharashtra	Dabhol Power Project	LNG	2015 (Ph I 695 + Ph II 1320) Revised to 2184 (Ph I 740 + Ph II 1444)	Enron Power USA, Bechtel, General Electric
Maharashtra	Bhadravati	Coal	1072	Central India Power Company Ltd. by Nippon Denro Ispat Ltd. (Mittal Group)
Odisha	Ib Valley	Coal	420	AES Transpower
Tamil Nadu	Neyveli Thermal Power Station	Lignite	250	ST-CMS Electric Company Private Ltd.

Source: (CEA, 2008)

However, these bold measures did not help much. Projects like the Mangalore power station promoted by Cogentrix or Bhadravati in Maharashtra never saw the light of the day. Jegurupadu and Godavari were commissioned, but ran into several challenges and for the last few years have been stranded for want of fuel. Initiated in the early 1990s, the two units of the Vishakhapatnam TPS promoted by the Hinduja group were commissioned recently in October, 2015 and March, 2016 respectively (EAC (Thermal Power), August 2016, p. 11). Had this project been commissioned as per the original timeline, the power purchase contract would have perhaps ended in 2016. It is not possible to delve into the details of each of the fast track projects, hence, the story of the Dabhol Power Corporation (DPC), promoted by the US based Enron Corporation, is briefly discussed below as a case study of the IPP policy.

2.2.3 Enron — a sordid saga

In 1992, MoU was signed between the US based Enron Development Corporation and the Government of Maharashtra (GoM). Under the MoU, Enron would build a combined cycle gas technology based thermal generation plant with an installed capacity of 2015 MW in two phases[4]. In April 1993, Bechtel Enterprises and the General Electric Company (GE) joined Enron to form the Dabhol Power Company (DPC). The project would run on natural gas, which was to be imported from Enron's gas fields in Qatar in liquefied form via a sea route (Wagale, 1997). Hence, along with the power plant, Enron would also build a regasification plant (also referred to as the LNG terminal) with a significant spare capacity. It was for this purpose that the plant was located near the port of Dabhol on the west coast.

In December 1993, DPC entered into an agreement with the GoM for the first phase. The GoM was not bound to sign a power purchase agreement (PPA) for the remaining capacity. The capacity that Enron was planning to build was about one fifth of the total installed capacity of the state at that time. Considering Maharashtra's demand supply situation at the time, there were serious concerns regarding the need for such large scale capacity addition and also the choice of technology, fuel availability, and affordability. The project also faced criticism on account of the potentially adverse social and environmental impacts and also concerns regarding energy and national security (Wagale, The Enron Story, 1997). A statement made by Ms Linda Powers, the former Global Vice President of Enron, regarding an

4. This was comprised of 695 MW (Phase I), and an additional 1320 MW (Phase II). Subsequently, it was revised to 740 MW (Phase I) and 1444 MW (Phase II). Still later, the central commission further de-rated it and as on 2016 the installed capacity is 1967 MW.

alleged spending of US $ 20 million (~ ₹ 215 crores in 2016) for "educating" Indian officials, ruffled quite a few feathers and fuelled allegations of corruption.[5] The project was also strongly contested in the judicial forum. About a dozen public interest litigations have been filed against the project in the High Court and a few in the Supreme Court (Prayas Energy Group 2001).

Given such concerns and the secrecy under which the project MoU was negotiated, it soon became a major political issue during the 1994 state assembly elections. After the elections, the new government was formed by a coalition which had campaigned against the project and had promised to review it. However, after a series of convoluted twists and turns, the new government reneged on its initial decision to scrap the project, and instead renegotiated the tariff and signed a contract with Enron in 1996 for both phases including the entire capacity of 2015 MW. The contract was heavily lopsided in Enron's favour and it was estimated that the company would earn a rate of return to the tune of 21–30%, which was almost double the norm for such projects. In spite of this, the project was championed by many public figures and the government projected the tariff to be around ₹ 2.4/kWh and even ₹ 1.89/kWh at the time of signing the PPA in 1993 and its amendment in 1996 respectively.

As per one analysis published in 1995, if the project had to make economic sense for the Maharashtra State Electricity Board (MSEB), i.e. if the MSEB were to make a net profit (positive NPV) on account of DPC power over the term of the contract, the average consumer tariff of MSEB would need to increase at more than 15.5% per annum for the next two decades! To put this number in perspective, it would be useful to note that the actual average tariff increase for MSEB in the decade spanning 1985 to 1995 was 12% (Sant, Dixit and Wagale, 1995, pp. 29, 30). In spite of such preposterous economics, the state government gave sovereign guarantees, and the central government issued counter guarantees, in case of payment default by MSEB (Standing Committee on Energy, 1995–96, p. 38).

In 1999, when the first phase of the plant was commission and the project started generating, the cost of generation shot to ₹ 7.5/kWh. By 2000, it became clear that even if only Phase I was allowed to continue, it would lead to the financial collapse of not just the MSEB, but potentially of the state government (Sant and Dixit, 2001). The cost was so high for two main reasons: a) the dollar linked high cost of the

5. Testimony by Linda Powers, Vice President, Enron Development Corporation before the Committee on Appropriations, Subcommittee on Foreign Operations, U.S. House of Representatives, 31st January, 1995.

imported fuel, and b) the capacity was contracted as a base load plant and hence, even in the absence of demand, the full capacity charge had to be paid. By this time, an electricity regulatory commission was set up in the state and hence the MSEB was forced to seek a regulatory approval for tariff increase. The regulatory process exposed the real cost of power, as the commission restricted power purchase from DPC to only 3044 MU (PLF of 47 %) during the FY 2000–01 at an average tariff of ₹ 5.7/kWh (Prayas Energy Group 2001).

These developments forced the GoM to review the project yet again, and in November 2000 it set up a committee with Dr. Madhav Godbole (Ex. Chairperson MSEB and Former Union Home Secretary), Dr. EAS Sarma (Ex. Union Power Secretary), and Mr Deepak Parekh (then Chairperson, Infrastructure Development and Finance Corporation or IDFC).

The committee published its report in 2001, which in unanimous and unequivocal terms indicts the project on its many failures while clearly establishing the inappropriateness of the project and its excessive costs. The report also highlighted the many governance lapses and the costs it imposed on the public. It also provided recommendations to mend the many faults in the power procurement process. Amongst other things, one of the major recommendations of the committee was to increase transparency in public procurement processes. The report notes that "While commercial considerations may apply in certain instances, the Committee is convinced that, in the case of the PPAs, this concern is overwhelmingly overridden by the public interest.", and "The public therefore has a right to know what is being contracted on their behalf". Hence, the committee recommended that "***all*** *documents, including associated contracts, related to* ***all*** *IPPs, including, in particular, DPC, be published by the Government of Maharashtra within two months*" (Godbole Committee Report April 2001, 83) (emphasis in the original).

The report observed that the DPC project was comprised of a few sub-projects, all of which were not related to power generation, but that the MSEB was paying for these. For example, the power plant was using only 42% of the LNG terminal capacity, though its entire cost was loaded on the MSEB. Given the number of LNG based projects in the pipeline, the committee recommended restructuring to separate the LNG terminal business from the power plant. It also recommended that energy payments should be based on the 'pay-as-use' principle rather than the 'take-or-pay' principle, and suggested to adopt a two-part tariff structure to further optimise the costs. With regard to other IPP projects in Maharashtra, the committee noted

that "MSEB defer all PPAs with IPPs and re-examine them in accordance with the Least-Cost Plan and in any case till such time the demand levels in the State permit full absorption of power generation from such IPPs". However, the most interesting recommendation which squarely deals with the issue of competitiveness of the project was that the committee recommended that the DPC should be free to sell its power to other entities if it can find a willing buyer. In this regard, the committee notes: "*Alternatively, DPC may find the conditions of restructuring too onerous and may believe it has prospects of earning better returns if it had the contractual freedom to sell power to other parties directly. If so, the Committee recommends that DPC could be allowed to sell power to any such parties, outside MSEB system, as it may be able to find,* ***but only if DPC then agrees to relieve MSEB of all its contractual obligations relating to the power plant***" (Godbole Committee Report, April 2001, p. 92) (both emphases in the original). Unfortunately, most of these recommendations could not be implemented.

The problem with the DPC was not just bad economics. The plant also failed to meet its technical commitments and in spite of being a gas based project, it could not vary its generation in accordance with load dispatch instructions. This technical and operational glitch enabled the MSEB to rescind the contract in 2001. During this time, the Enron Corporation also found itself engulfed in a major financial scandal and filed for bankruptcy in the US. In spite of repeated suggestions, the government failed to buy Enron's equity in DPC. Had this been done, lot of further litigation and costs arising on those accounts could have been avoided.

Subsequently, the project was revived as the Ratnagiri Gas and Power Pvt. Ltd. (RGPPL) in July 2005. The cost of reviving the project was estimated to be between ₹ 6,000 – 8,000 crores, which was entirely borne by the Indian taxpayer (Wagale, 2005). The project now became a joint venture of NTPC, GAIL (India) Ltd, and the MSEB Holding Company along with some public financial institutions. After revival, commercial operation of Block II and Block III, each of 663.5 MW, was declared in 2007. Block I of the generating station of 640 MW was commissioned only in May 2009 after significant repair.

Since 2007, the revived project has consistently failed to perform either on account of technical and operational problems or due to a lack of fuel. Hence, treating it as an in-firm source, the MSEDCL refused to pay the capacity charges (MERC, 2015, 120). This decision of the MSEDCL has been challenged by RGPPL. However, because of gas shortages, the plant has been shut down since December 2013 (Jog, 2014).

The Gas Supply Agreement of RGPPL with KG-D6 expired in March 2014, and since then there is no firm gas allocation available for the plant, the MSEDCL has (yet again!) terminated its contract with RGPPL. The said termination has been challenged by RGPPL (MERC, 2015, p. 125).

In the meanwhile, lenders have sought to convert more of the loans into equity and the state cabinet cleared yet another proposal to revive the project. In a press statement the Minister said that "due to ₹ 7,800-crore debt, the gas-fired project, located in Ratnagiri district, was on the verge of being declared a non-performing asset (NPA). RGPPL will be demerged into two separate companies owning the currently-defunct power plant and its LNG terminal, respectively" (Jog, 2016). Thus, after more than a decade and half, the government is finally contemplating to implement the Godbole committee's recommendation.

In 2015, in an attempt to utilise the stranded gas based capacity in the country, the central government announced a subsidy scheme to enable such capacity to generate power. This scheme is discussed in Section 2.4.2 below. RGPPL is able to generate around 300 MW by using gas allocation from this scheme. It is interesting to note that the MSEDCL is not buying this power, but central railway in Maharashtra, which is one of the high paying consumers of the MSEDCL, is buying it from RGPPL under open access. It is ironical that after almost two decades since its commissioning, the DPC is partially operational only because of subsidised fuel allocation by the central government (financed by the exchequer), but the brunt of it is still borne by Maharashtra's electricity consumers, as on account of this generation the MSEDCL loses the valuable cross-subsidy from a high paying big consumer like the railways.

Though, the Enron saga with its numerous lost opportunities remains a particularly ugly case of political and policy failure; however, it is symptomatic of the governance challenges and the sheer neglect of rational planning in generation capacity addition.

2.2.4 Lessons from the IPP policy

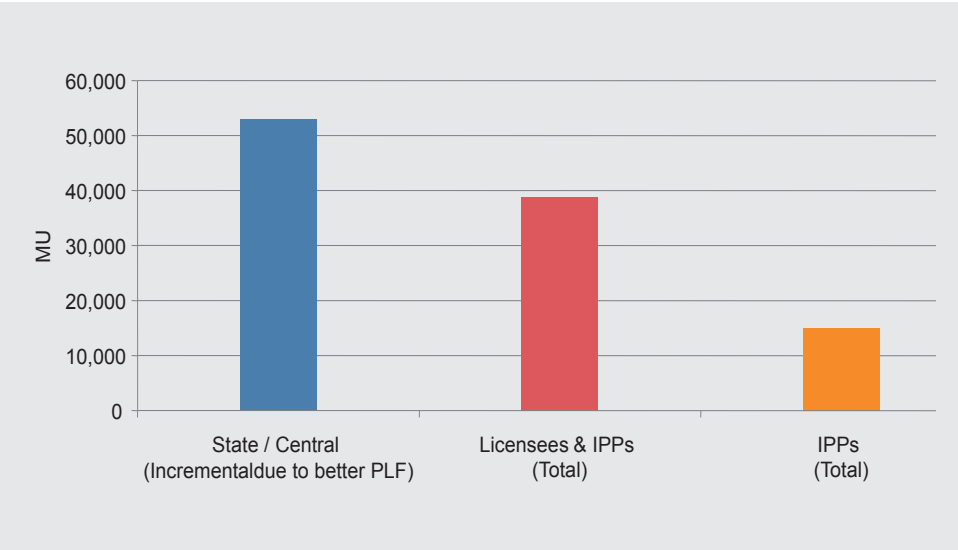
Looking back, one notices some fundamental flaws in the 1992 IPP policy. There was a disproportionate focus on attracting private (especially foreign) investments. Because of this, efforts towards enabling proper demand assessment and rational power purchase planning, instilling transparent processes for monitoring and regulation, and creating a level playing field which would be conducive for genuine competition remained totally neglected.

While the policy talked about faster clearances and allocation processes for fuel linkages, especially coal, issues such as feasibility of production, transportation, and other such practical constraints were not duly considered. More importantly, the issue of demand estimation and whether the IPP generation is the least cost, best option for meeting the demand for power was not even a part of the policy discourse. It was simply assumed that the SEBs would buy the power from projects for which MoUs had been signed. The most alarming aspect was this absolute disregard of SEB finances and their capacity to pay for such expensive power. Also, the fact that this capacity was far more than all the states' demand put together did not seem to ring any alarm bells. By one estimate, it was more than the total installed capacity of the country at that time (PEG, 2001a, p. 5).

To make matters worse, the IPPs were not selected through a transparent bidding process, and the terms and conditions of the MoU and subsequent power purchase agreements (PPA) were strictly guarded as 'confidential' documents. Curiously, the private sector did not voice any concerns against such an unfair selection process. Because of the secrecy, in case of many of these projects the choice of fuel and/or technology was inappropriate, but the issue could not be debated when the MoUs were signed. Many of the projects were based on expensive imported fuel and technology. As a result, the final tariffs that the SEBs, and hence the consumers, would have to pay, were substantially higher than the prevailing norms or potential alternatives (Phadke, 2001).

In terms of contribution in energy generation, it is instructive to see which sources contributed to the actual power generation during IPP era. Figure 2.2 shows energy generation by IPPs alone and that by private generating licensees and IPPs combined in FY 2002, and compares it with incremental generation on account of improved plant load factor of the state and centre sector stations. The increment is with respect to the generation from these stations in 1992, after accounting for any increase in capacity. As can be seen from the figure, after a decade of concerted policy effort, the IPP generation was about a third of the incremental generation achieved by the state and central sector plants by simply improving the plant load factor. Thus, while the IPPs remained engulfed in controversies, the state and central generating stations saved the day for the country's power sector.

Figure 2.2: IPP generation contribution to total energy generation in FY 2002



Source: Prayas (Energy Group) compilation, September 2010.

2.3 Mega power policy: 1995 – present

Not to be discouraged by the early setbacks of the IPP policy and to further boost the capacity addition efforts, the central government in November 1995 formulated the 'mega power policy' for setting up plants of 1000 MW or more and supplying power to more than one state (MoP, 1995). The policy acknowledged that many MoUs for projects had been signed at the state level, but without providing any assessment of how much capacity was in the pipeline and how much more was needed, it simply stated that "*it needs to be recognised that in order to improve the power supply, we would have to set up more than 10,000 MW of the capacity every year in the next few years which is an onerous task*." And onerous it was. To appreciate the magnitude of the challenge set by the ministry for itself, one can compare it with the capacity addition in the last two decades. It is only during the 12th plan period (2012-2017) that the country could actually manage to add capacity of more than 10,000 MW per year and already it has led to concerns regarding surplus (Shastri, 2016). This is in spite of the fact that the demand for power has increased manifold since what it was in 1995.

The policy argued that resources such as coal and hydel potential are located in few areas whereas demand for power could be elsewhere. Hence setting up large

projects (more than 1000 MW) at pit head or best possible sites from the point of view of hydropower potential would help to efficiently use these resources.

Learning from the IPP policy, the government this time introduced guidelines for competitive bidding for project selection (CEA, 1996). The policy stated that bidding would lead to efficient discovery of tariff and bring the much needed financial relief for the SEBs. The 1996 guidelines suggested a two-stage approach based on a Request for Qualification (RFQ) and Request for Proposal (RFP), and identified several parameters which could be used for bid evaluation based on a given weightage.

POWERGRID was entrusted with the responsibility of selection of promoters and finalising PPAs with state electricity boards. It was also supposed to provide "*escort services, act as a facilitator and catalyst, arrange for wheeling of power generated by these mega projects and enter into separate agreement with the user SEBs/States on Transmission Tariff* (MoP, 1995).

To ensure faster project development, the CEA was supposed to identify potential sites, and the NTPC was supposed to prepare the project feasibility reports. The policy also provided tax holidays to the identified projects. The import of capital equipment was free of customs duty for these projects. In addition, the promoter could claim a tax holiday period of 10 years in any block of 10 years within the first 15 years of the term of the project.

The policy was revised in 1999 to set up the Power Trading Corporation (PTC) with majority equity participation by the Power Grid Corporation of India Ltd. (PGCIL), along with NTPC, Power Finance Corporation (PFC) and other financial institutions. Prior to the 2003 Act, which allowed trading of electricity; the PTC would buy the power from the projects and sell it to identified SEBs. The revised policy also introduced new eligibility conditions for states, which included setting up of regulatory commission under the 1998 Electricity Regulatory Commissions Act, and privatising distribution in cities having a population of more than one million. The revised policy extended the benefits of mega power project status also to state owned projects, however they were required to deal with SEBs directly and not through the PTC (MoP, 1999).

In spite of all the right intentions, the mega power policy could never translate its objectives into the stated benefits. Till date, only about 19 projects, including the public and private sector, have been identified as mega power projects. The first

private sector mega power plant to be commissioned was Jindal Power's 1000 MW thermal plant in Tamnar, Chhattisgarh. It started full commercial operation only in August 2008, more than a decade after the mega power policy was first introduced (The Hindu 2008).

Although the mega power policy was a much better designed scheme than the IPP policy, it failed to elicit interest amongst the buyers (i.e. SEBs), who were supposed to act based on these guidelines. The reason for this could be that states had already signed a large number of MoUs for much bigger capacities than what they needed for the next 5–10 years. The governance issues regarding the MoU had already been highly politicised and this may have prevented the state governments from openly reviewing the capacity addition plans, in spite of the fact that there was considerable doubt regarding feasibility of most of the MoU projects. Also, the lack of discretion to the states in terms of selecting the project under this scheme perhaps dampened the interest.

One of the interesting aspects of the mega power policy was that the entire risk of payment default by the SEBs was borne by an intermediary, i.e. PTC, which was entitled to charge only a small trading margin in exchange for this big risk. The creation of the PTC to promote markets was more of an effort to delink the (private) generators from the financial problems of the real buyers, i.e. the insolvent SEBs, than an acknowledgement of the SEB's unsustainable business model and a need to address this issue. Today, even a decade after the Electricity Act 2003 and provisions such as power exchanges and open access, the PTC continues to hold more than one third of the total market share in the short-term power market (CERC, 2015, p. 30).

The mega power policy and its subsequent revisions highlight the underlying acknowledgment of the issue of distribution finances and sustainability. However, the solutions remained limited to prescriptions such as to undertake bidding to select generation projects and privatise distribution in cities. A more detail critique of the reforms in the distribution sector is presented in the Chapter 5, *Electricity distribution: On square one, even with reforms after reforms*. From the point of view of generation and looking at the subsequent policy developments, one is compelled to believe that in spite of identifying serious problems, the policy makers chose to focus their efforts on attracting investments for increasing generation capacity, rather than dealing with the issue of affordability and sustainability of such operations.

2.4 Competitive bidding for power procurement

Underlining the need for competition, Section 63 of the Electricity Act, 2003 allows regulatory commissions to adopt a tariff for generation that has been discovered through a transparent bidding process conducted as per the guidelines issued by the central government for this purpose. Accordingly, the government notified competitive bidding guidelines for generation capacity addition in January 2005 (GoI, 2005). The National Tariff Policy also encourages DISCOMs to undertake all new capacity addition through a competitive bidding route (GoI, 2006, p. 2).

As per the 2005 guidelines, bidding could be undertaken through two ways viz. case-1 and case-2. Under case-1 type of bidding, the procurer i.e. the buyer of the power, which is a distribution company, does not specify the location, technology or fuel. The developer has full freedom to decide these factors. On the other hand, case-2 is location and/or fuel specific bidding i.e. the procurer specifies the location and/or fuel and could also be responsible for arranging it.

As a part of the guidelines, the central government also notifies the Standard Bidding Documents (SBD) such as the Request for Qualification (RFQ), Request for Proposal (RFP) and Power Purchase Agreements (PPA) for both case-1 and case-2 bidding processes. Any deviations from these standard documents need regulatory approval. This is a very important feature of the guidelines aimed at ensuring transparency and reducing information asymmetry. The standard bidding documents for case-2 and case-1 were notified in 2006 and 2008 respectively.

The guidelines emphasise a fair and transparent process for bidding and give the bidders an option to pass on the fuel price variation and other related risks by quoting various escalable and non-escalable charges. The guidelines provide a two-part tariff structure[6] comprising of fixed (also called capacity) and variable (also called fuel or energy) charge. Variable charge has sub-components of fuel cost, transportation and fuel handling with the option of quoting escalable and non-escalable charges for each of these sub-components. Escalable parameters allow bidders to transparently pass on potential price variations for each of the sub-components. As discussed further, the escalable components play a crucial role in deciding competitiveness of a given bid and hence the ultimate tariff impact.

6. In scheduling generation capacity, principle of 'merit order dispatch' is followed. Under this principle, all the available generation is stacked based on lowest to highest variable cost. Depending upon demand for power, generation with high variable cost may or may not be dispatched. The reason for having a two-part tariff is to allow the generators to recover the fixed cost, i.e. the capital investment, even if the generation capacity is not utilised because of a cheaper (fuel based) generation option being available.

The bids are evaluated based on the levelised tariff[7] and power purchase agreement (PPA) is signed with the lowest (L1) bidder. The PPA allows change in the agreed tariff only under two circumstances: a) change in (Indian) law: whereby a legal action of a government body or a court imposes any cost or results in benefit, and b) force majeure, which implies an unforeseen event that prevents the performance of obligations under contract or unavoidably delays in the process.

For the purpose of transparency, after the PPA has been signed the procurer i.e. the distribution company buying power, is required to publish on its website not just the details of the winning bidder but also anonymous comparison of all the financial bids with the winning bid. The procurer is also required to publish notice with details of the signed PPA in at least two national dailies and also to put it up on the company's website. The final signed PPA along with the necessary certificates and reports is to be submitted to the regulatory commission for the adoption of the tariffs.

Thus, learning from the governance issues of the IPP era, the emphasis was correctly on enabling a fair and transparent bidding process. Enabling flexibility without compromising transparency was a notable feature of the 2005 bidding framework.

2.4.1 Ultra Mega Power Projects Policy

Under the same bidding framework, the Ministry of Power also launched what it called the Ultra Mega Power Projects (UMPP) Policy, which defines UMPPs as large sized projects, approximately 4000 MW each, being developed on a Build, Own, and Operate (BOO) basis. Under this policy, it was stated that:

> "In order to enhance investor confidence, reduce risk perception and get a good response to competitive bidding, it was deemed necessary to provide the site, fuel linkage in captive mining blocks, water and obtain environment and forests clearance, substantial progress on land acquisition leading to possession of land, through a Shell Company. In addition, Shell companies would also be responsible for tying up necessary inputs from the likely buyers of power." (MoP, 2006)

7. Levelised tariff is a concept used in thermal power sector to compare project costs. It is an indicative tariff which, if paid over the entire duration of the PPA, would match the value of tariff that is quoted for each month or year, over the term of the contract. Thus, for the buyer, it represents the net present value of payments (monthly, yearly or per unit) to be made over the contract duration and hence makes it possible to compare tariff quoted by different projects for the same duration. The discount rate used for calculating the levelised tariff is a crucial variable and is notified by the central commission every six months. For more information see www.cercind.gov.in/escalation_rates.html

All UMPPs were proposed to be coal-based and using super-critical steam technology, and were estimated to require 10% less coal than the prevailing sub-critical steam technology. So far, the bidding process for four UMPPs has been completed. A brief summary of tariffs discovered is presented in Table 2.2 below.

Table 2.2: Status of the Ultra Mega Power Projects (UMPP) awarded so far

Project Name and Location	Developer	Fuel	Year of Award	Levelised Tariff Rs./unit
Coastal Gujarat Power Limited, Mundra UMPP, Gujarat	Tata Power Company Ltd.	Imported coal	7-Apr	2.26
Sasan Power Limited, Sasan UMPP, Madhya Pradesh	Reliance Power Ltd.	Pit head coal block	7-Aug	1.19
Coastal Andhra Power Ltd., Krishnapatnam UMPP, Andhra Pradesh	Reliance Power Ltd.	Imported coal	8-Jan	2.33
Jharkhand Integrated Power Ltd., Tilaiya UMPP, Jharkhand	Reliance Power Ltd.	Pit head coal block	9-Aug	1.77

Source: (Power Finance Corporation, 2007).

The UMPP tariffs have been the lowest discovered tariffs so far, and hence it set new benchmark and significantly piqued expectations. The discovery of such low tariffs was attributed to the many unique characteristics of the UMPP scheme, such as 'developed sites' with significant groundwork in terms of clearances and partial land acquisition being done by the shell company, international arrangements for procuring plant equipment, and increased transparency and competition. However, the execution of the UMPP scheme has been far from smooth.

Sasan UMPP

The Sasan UMPP, which saw the lowest discovered tariff for a domestic coal-based pit head project, was engulfed in issues concerning the coal allocation right from the time of bidding. While both Tata Power Company Ltd (TPC) and Reliance Power had submitted bids, initially a consortium led by Lanco Infratech won the bid. Subsequently it was annulled on account of changes in the consortium post bidding and without prior approval. An empowered group of ministers (EGoM) was formed to look into the issue which declared the Lanco bid as void. Following this, a notice was served to the other bidders to extend the bid validity. However, the reasons for requiring the qualified bidders to extend the validity of their bids

were not specified. While Reliance Power extended its bid validity, TPC did not do so. Later, bidders who had extended the bid validity were asked to match the earlier winning bid. In response, Reliance Power reduced the quoted tariff from its initial bid of ₹ 1.29 per unit to ₹ 1.19 per unit (i.e. it matched the tariff quoted by Lanco), and bagged the project.

Around the same time, Reliance Power entered into a MoU with the Government of Madhya Pradesh (MP) for setting up a 4000 MW power project in Chitrangi in MP. For the Chitrangi Project, the government of MP approached the GoI to allow Reliance Power to use surplus coal from the Sasan mines. An empowered group of ministers in 2008 recommended to the ministry of coal to permit Reliance Power to utilise any surplus coal in this manner. It is important to note that the possibility of surplus coal production from the mines allocated for the Sasan project was known. In November 2006, the ministry of coal had written to the PFC, the nodal agency for bidding and to all the qualified bidders that the central government reserves the right to permit diversion of incremental coal from the Sasan UMPP. However, the manner in which such diversion would be effected and whether the winning bidder would be allowed to utilise the surplus coal was not explicitly specified.

The low tariff discovered for Sasan might have been on account of the surplus coal that could be used by the developer for other projects. It is important to note that the developer had to pay no price for this surplus coal, so it was available at essentially the mining cost (along with royalties, taxes, cess, etc. that would be payable). As per a report of the Comptroller and Auditor General, the surplus coal was about 9 MTPA, which could support a capacity of around 2 GW (half the existing installed capacity or 1.5 times the project requirement) (CAG, 2012, p. 32).

Claiming that the permission granted to Reliance Power to utilise the surplus coal from the Sasan captive mines for its other project completely changes the economics of the Sasan UMPP, the TPC in 2009 challenged this decision of the central government before the Delhi High Court. It was also argued that the bidding documents did not clearly and explicitly allow for such arrangements. The writ petition filed by the TPC was dismissed by the High Court on two grounds, a) 'suppression of a material and relevant fact' as the TPC did not disclose the existence of the MoC letter dated November 2006 pertaining to the government reserving the right to divert surplus coal from Sasan, and b) not having extended the bid validity, the TPC had effectively quit the race and hence did not have any locus standi to maintain the writ petition (Delhi High Court, 2009). The TPC challenged

the decision of the High Court before the Supreme Court, which ruled that in light of the subsequent developments pertaining to coal utilisation from captive blocks, the High Court order was infructuous. However, it allowed the TPC and any other party to agitate on the issue before the High Court or any other suitable forum (Supreme Court of India, 2015). It is not clear if the TPC has pursued the matter further.

Another controversy pertaining to the Sasan project has to do with the date of commissioning of its first unit. Reliance power declared the commissioning date to be 31st March, 2013 for the first unit. If this claim was to be accepted, the first year tariff of ₹ 0.69 per unit as per the PPA would be applicable for just one day, and a higher tariff would become applicable from 1st April 2013 as the financial year would change. This would cause a tariff impact of around ₹ 1000 crores for consumers. The commissioning date was also contested on the grounds that the commissioning test was not performed as per the PPA. The matter was raised before the central commission which ruled against the date declared by Reliance Power. Reliance appealed against the CERC order before the Appellate Tribunal for Electricity (ATE) which ruled in its favour. The tribunal found that though commissioning of the unit had not been achieved on 31st March, 2013 in accordance with the PPA, the procurers had supposedly waived their right to demand performance at 95%, and that the performance of Unit No.3, which was only roughly 17% of its contracted capacity, was accepted by all the procurers, and that therefore there was a waiver of this essential condition, which would then entitle the generator to treat 31st March, 2013 as the date of commissioning. Ruling against the judgement of the tribunal, the Supreme Court observed that "… if any element of public interest is involved and a waiver takes place by one of the parties to an agreement, such waiver will not be given effect to if it is contrary to such public interest", and "if there is any element of public interest involved, the court steps in to thwart any waiver which may be contrary to such public interest". Further, the court also established that the finding of the tribunal that any such waiver had been given by the procurers was itself erroneous and hence the judgement was set aside (Supreme Court of India, 2016, pp. 37, 39).

In a separate chain of events[8], the Supreme Court in December 2014 cancelled all the captive coal block allocations on the grounds of such allocation being illegal, ad-hoc and arbitrary. The said judgement, however, did not cancel the blocks

8. These events are discussed in detail in Chapter 6 dealing with the coal sector.

allotted to UMPPs, but disallowed the utilisation of any surplus coal for commercial purpose (Supreme Court of India, 2014, pp. 3, 23). Citing this development as a 'breach of representation', Reliance Power Ltd. has sought termination of the PPA and has asked the PFC to buy out its Sasan UMPP (Trivedi and Jai, 2015). The procurers have not accepted the termination notice of Reliance Power and the matter is pending before the High Court. In addition, the project has also filed several petitions seeking revision of quoted tariff on various grounds and some of these claims are pending before various fora.

Mundra UMPP

Coastal Gujarat Power Ltd. (CGPL), a wholly owned subsidiary of Tata Power Company Ltd (TPC), is responsible for building and operating the Mundra UMPP, which is entirely based on imported coal. Quoting a levelised tariff of ₹ 2.26 per unit (the lowest so far for an imported coal based project), TPC won the bid and signed the power purchase agreement (PPA) in April 2007. For this project, TPC planned to import coal from Indonesia and for this purpose, the company also bought stake in an Indonesian mining company.

In September 2010, the Indonesian Government notified a regulation[9] which directed the holders of mining permits for coalmines in Indonesia to sell coal in domestic as well as international markets as per a prescribed benchmark price. All pre-existing contractual arrangements were to be aligned accordingly (CGPL, 2012). Claiming that because of this regulation, it was forced to pay a higher cost for coal import than what it had assumed at the time of bidding, the CGPL filed a petition before the central commission seeking tariff revision under the 'Change of Law' and/or 'Force Majeure' related provisions of the PPA (CGPL, 2012). It is important to note that at the time of bidding, the CGPL willingly opted to pass on only 45% of the fuel price escalation, while the remaining 55% was quoted in the form of a fixed rate for the entire 25 year term of the contract.

After a long drawn process, the commission concluded that there was neither a change in law nor a force majeure event as per the PPA, and hence no contractual ground for tariff revision. However, using its regulatory powers the commission decided to grant the project, what it called a 'compensatory tariff' of ₹ 0.52 per unit

9. This was a further roll out of the 2009 Law on Mineral and Coal Mining; on 23rd September 2010 the Ministry of Energy and Mineral Resources (MEMR) issued Regulation No 17/2010 on Guidelines on the Determination of the Reference Price of Mineral and Coal Sales.
www.hhp.co.id/files/Uploads/Documents/Type%202/HHP/al_hhp_minimumcoalmineralpricing_oct10.pdf

(CERC, 2014a, p. 104). This decision of the CERC completely insulated the project from the fuel price variation risk it had willingly assumed to win the contract and passed it on entirely to the consumers. The decision of the CERC was challenged by the procurers and consumer representatives[10], and the Appellate Tribunal for Electricity (ATE) vide its judgment dated 7th April 2016 has set aside such use of regulatory powers to bailout projects, when no relief is possible under the contract (ATE, 2016, pp. 473). The ATE however declared the promulgation of the Indonesian regulation as a force majeure event and directed the CERC to grant relief that may be available under the PPA for such an event. A more detail analysis of the said ATE judgement is provided at the end of this section.

Tilaiya UMPP

The contract for the Tilaiya UMPP was awarded in 2009, however not much progress happened in terms of actual project development. In 2013, while the project was still under construction, Jharkhand Integrated Power Ltd. (JIPL) promoted by Reliance Power, i.e. the Tilaiya UMPP, approached the CERC with a petition seeking compensation due to 'change in law' events. While this matter was being heard by the CERC, an application to withdraw the case on the grounds of contract termination was filed by Reliance Power. However, the procurers i.e. DISCOMs buying the power complained that the said withdrawal application was filed even before any termination notice was served to them. Sensing trouble, Reliance Power approached the Delhi High Court to declare that the termination notice issued by it was valid and binding, while the matter was still being heard by the CERC (CERC, 2015). Media reports suggest that in what seems like an out of court settlement, the buyers seem to have accepted the termination notice (FE Bureau, 2015). Being the lead buyer, Jharkhand is expected to buy 100% shares in the UMPP and also compensate Reliance Power for the expenses incurred by it on heads such as land acquisition and cost of clearances (Jai, 2016).

Krishnapatnam UMPP

The bidding process for the Krishnapatnam based Coastal Andhra Power Ltd., also promoted by Reliance Power, was completed in early 2008. Like Tilaiya, in case of this UMPP also not much progress happened on ground in terms of developing the project. As this UMPP was also based on imported coal, in 2011, citing the change

10. Prayas in its capacity as an authorised consumer representative before the CERC has participated in the proceedings related to this matter and has opposed such tariff revision. Prayas has also filed an appeal before the Appellate Tribunal for Electricity challenging the said decision of the CERC.

in Indonesian law, the project sought revision of quoted energy charge. The Andhra Pradesh Central Power Distribution Company Ltd. (APCDCL), which is the lead buyer of power from this UMPP, claimed that the developer had abandoned the project construction work even before the Indonesian regulation came into force and hence was not entitled to any relief. Citing lack of progress on the project construction front, the Andhra Pradesh Southern Power Distribution Company Ltd. (APSPDCL) issued a contract termination notice in March 2012 and sought payment of ₹ 400 crores from the developer for the default in complying with the contract (CERC, 2015h).

Reliance Power challenged this termination notice before the Delhi High Court. During the pendency of the said appeal before the High Court, Reliance Power filed another petition before the CERC seeking revision of the quoted tariff. Since the appeal before the Delhi High Court was pending, the CERC decided not to interfere and directed the parties to approach it after the High Court had dealt with the matter (CERC, 2015h). The current status of the contract is not clear though it seems that efforts are on to terminate the contract in the same manner as the Tilaiya UMPP. As per media reports, the distribution companies buying the power have demanded that Reliance Power should withdraw the pending appeals if it wishes for an amicable exit from the project (PTI, 2016).

Thus, while Sasan and Mundra UMPPs at least managed to complete the project construction and started generating power, the other two UMPPs were terminated without any significant progress in terms of project development. Before litigations pertaining to Sasan and Mundra UMPPs caught full steam, attempts were made since March 2010 to invite bids for three other UMPPs, namely Cheyyur in Tamil Nadu, Surguja in Chhattisgarh, and Bedabahal in Odisha. In case of the Cheyyur project, while all the private players pulled out of the bid process, NTPC Ltd. emerged as the sole bidder. Likewise, NTPC and an NHPC-BHEL joint venture were in the fray for the Odisha UMPP (Latish, 2015). However, after two rounds of calls for bids, efforts have been aborted citing tepid response from the private sector (Jai, 2015).

2.4.2 Issues pertaining to domestic coal supply

By 2011, in addition to the 16 GW contracted under the UMPP policy, capacity of more than 26 GW had been contracted on long-term basis under the case-1 and case-2 bidding route. Excluding the UMPPs, only about 17% (4,324 MW) of this capacity is based on imported coal, while about 70% (17,730 MW) is dependent on

domestic coal, mainly linkages (Gadag, Chitnis and Dixit, 2011, pp. 6, 10). Thus, it is essential to note that a large portion of the capacity contracted through bidding was dependent on the performance of the domestic coal sector.

Under the New Coal Distribution Policy (NCDP) of 2007, Letter of Assurance (LoA) would be granted to any power project based on the recommendations of the standing committee, which decided allocation of long-term linkages. Subsequent to the project meeting various development milestones, the LoA would be converted into a Fuel Supply Agreement (FSA). However, the coal supplier did not assume any contractual obligation to supply coal as per the grade and/or quantity and price mentioned under the LoA. The LoA under the 2007 NCDP also makes it very explicit that in case of shortages, coal would be imported to meet such shortfall and the price of such imports will have to be entirely borne by the buyer i.e. the power generator (GoI, 2007, p. 4). Thus, there was no contractual assurance with regard to domestic coal quality, quantity or price. Most projects, which participated in the bidding processes and won contracts, relied on the LoAs for quoting the fuel charge. Therefore, it would be fair to say that all bidders participated in the bidding process with the full knowledge of the underlying fuel risks.[11]

However, as the projects approached commercial operation and the fuel price risks started becoming apparent; many projects approached the regulatory commissions seeking revision of the quoted tariffs. Table 2.3 gives details regarding some of the competitively bid projects that are seeking tariff revision on account of fuel related issues. As discussed later in the chapter, many state commissions accepted such demands of the projects to revise discovered tariffs and allowed, what they termed as 'compensatory tariff' over and above the PPA agreed tariff. The compensatory tariff approved by various commissions was in the range of ₹ 0.50 – 1.50 per unit and would have resulted in tariff impact of around more that ₹ 3000 crores per year for the consumers.

By 2014, more than half of the competitively bid capacity was under litigation seeking revision of the quoted tariff. Since the bidding guidelines provided complete flexibility to the bidders in terms of deciding the level of fuel price risk they wish to assume or pass on, it was expected that the policy makers will object to any post-facto changes to discovered tariff. Unfortunately, that has not been the case.

11. This issue has been discussed in more detail in Chapter 6 concerning the coal sector.

Table 2.3: List of competitively bid projects seeking tariff revision on account of fuel related issues

Generating station / Company promoting the project	Capacity in MW	Forum
Adani Mundra power plant	3425	GERC, CERC, ATE & Supreme Court
Adani Power Rajasthan Ltd.	1320	RERC
Adani Power Maharashtra Ltd	3300	MERC & ATE
EMCO Energy Ltd.	300	CERC
GMR Kamalanga Energy ltd.	1400	CERC
RattanIndia Power Ltd. (Indiabulls)	1200	MERC & ATE
JSW Energy	300	MERC, ATE
Lanco Anpara Power	1200	UPERC, ATE
Sasan UMPP	4000	CERC, ATE, High Court & Supreme Court
Tata Mundra UMPP	4000	CERC, ATE & Supreme Court
Total capacity under litigation	20445	

Source: PEG compilation from various regulatory orders till March 2016.

In fact, making a bad situation worse, the MoP through its letter to all state commissions suggested as follows (MoP, 2013):

> "…
>
> 4. As per decision of the Government, the higher cost of imported/market based e-auction coal to be considered for being made a pass through on case to case basis by CERC/SERC to the extent of shortfall in the quantity indicated in the LoA/FSA and the CIL supply of domestic coal which would be minimum of 65%, 65%, 67% and 75% of LOA for the remaining four years of the 12th Plan for the already concluded PPAs based on tariff based competitive bidding.
>
> 5. The ERCs are advised to consider the request of individual power producers in this regard as per the due process on a case to case basis in public interest. The Appropriate Commissions are requested to take immediate steps for the implementation of the above decision of the Government. (sic)"

Given the concurrent nature of electricity, it is pertinent to note that the central ministry has no legal authority to issue any policy directives to the state commissions. As a result, any such "advice" given by the central ministry is merely a guideline and the state commissions are not legally bound to act upon it.

Interestingly, in November 2011, the MoP issued a similar letter advising the state commissions on how they should operationalise open access, which is defined in the Electricity Act 2003 (MoP, 2011a). While most state commissions completely ignored this advice of the central ministry, few undertook suo-motu proceedings to clarify their stance on the matter. In one such exercise, the Maharashtra Commission ruled as follows (MERC, 2013b, p. 58):

> "136. The Commission is of the view that the MoP letter based on the opinion from M/o Law and Justice on Operationalisation of Open Access in Power Sector is nature of suggestion / advisory for development of market in the Power Sector to the State Commissions and may be looked as 'Policy Vision' of the Central Government."

Thus, in case of open access, the state commissions took a view that such advice of the MoP is not legally binding on them and hence they are not obliged to act based on it. However, when it came to revision of the competitively discovered tariff, the advice was taken much more seriously and in some cases, was also expeditiously acted upon. In this regard, the Maharashtra state commission's dealing of domestic coal related projects demand of revising quoted tariffs in worth noting. This is discussed in Box 2.1.

Box 2.1: Case study from Maharashtra regarding revision of discovered tariff based on domestic coal issues

In 2012, two generators, namely, Indiabulls Power Limited (now RattanIndia Power limited) and Adani Power Maharashtra Limited, which had executed PPAs under the Case 1 bidding process for capacity of 1200 MW and 1865 MW respectively with Maharashtra State Electricity Distribution Company Ltd (MSEDCL), approached the Maharashtra Electricity Regulatory Commission (MERC) for compensation on account of potential shortfall in supply of domestic coal and slippages in coal quality. The companies cited the amendment of the NCDP (Ministry of Coal, 2013) and the letter from the MoP (Ministry of Power, 2013) to CERC, as 'change in law' events under the contracts and sought tariff revision on these grounds. As these were

the first cases seeking revision of discovered tariff based on domestic coal related issues, and considering the fact that a capacity of more than 17 GW was contracted based on similar fuel arrangements, it was expected that the MERC would deal with these matters in a careful manner.

After hearing the matters, the MERC rejected the projects' claims regarding treating the amendment of the NCDP as a change in law event. However, citing the MoP advice, the CCEA decision, and the coal supply issues being faced by the power sector, the MERC using its regulatory powers decided to allow a compensatory tariff for passing on to consumers domestic coal supply related costs (MERC, 2014a). It also formulated a framework for this purpose. To enable computation of the compensatory tariff as per the framework, the commission directed the generators to file fresh petitions within 15 days of its order. Responding with unusual promptness, the directions were immediately complied with and neither the generators nor the procurer asked for any additional time or data or sought any further clarifications. Within one month of its initial order, the MERC issued a final order allowing compensatory tariff in August 2014 (MERC, 2014b) (MERC, 2014c). The final order has been challenged by all concerned parties, the generators, MSEDCL, and also the consumer representatives. As of December 2016, the matter is pending before the Appellate Tribunal for Electricity.

2.4.3 Issue of regulatory overreach

In April 2013, while dealing with the cases seeking revision of discovered tariff filed by Tata Mundra UMPP and Adani Mundra project, the CERC through its interim orders ruled that no relief was available under the terms of the respective contracts. However, it still decided to use its regulatory powers to make the projects viable and appointed a committee to evaluate the extent of the tariff increase required to offset such impacts (CERC, 2013, pp. 96,97). In February 2014, based on the committee's recommendations (Deepak Parekh Committee, 2013) and its own analysis, the CERC allowed what it termed as 'compensatory tariff', over and above the contractually agreed tariff (CERC, 2014). No public process was undertaken for this purpose, which is otherwise routinely followed for tariff revision matters in the electricity sector.

These orders were challenged before the Appellate Tribunal for Electricity (ATE). In its judgement dated 7th April 2016 regarding the compensatory tariff allowed by

the CERC, the ATE set aside the use of regulatory powers to bailout the projects (ATE, 2016, pp. 473-475). The tribunal ruled that relief, if any, can only be as per the provisions of the contract. While declaring that the promulgation of the Indonesian regulation or amendment of the New Coal Distribution Policy cannot be treated as change in law events under the contract, the tribunal, however, ruled that the increase in price of Indonesian coal on account of the passage of Indonesian regulations constitutes a force majeure event in terms of the PPA. In light of its findings, the tribunal directed the CERC to work out relief as per the force majeure provisions of the PPA.

While the tribunal's ruling regarding force majeure can be debated, it is safe to say that there is a major difference between the tribunal's decision and the earlier approach adopted by the CERC. After deciding that no relief is applicable under the PPA, the CERC still used regulatory powers to effectively restore the profitability of the project developers. Such an action by the CERC compromised sanctity of contracts. It had also completely reversed the risks that were willingly assumed by the generators to win the contracts. As against this, the ATE judgment upheld the contract provisions and provided limited relief under the force majeure provisions under the PPA.

It is important to note the context in which the ATE judgement has been delivered. As highlighted earlier, contract enforcement for the bidding based projects has become a serious challenge. There were instances where the generator terminated the PPA and the procurer simply chose not to act on the termination notice. In spite of this, neither the project developer, nor the lenders, informed the commission regarding the said termination for more than a year (MERC, 2013a). Similarly, some of the projects have failed to meet important milestones, but no legal action has been taken in this regard.[12]

In spite of not being bound by the decision of the CERC in any manner, the regulatory commissions in various states such as Maharashtra (MERC, 2014), Uttar Pradesh (UPERC, 2015) and Rajasthan (RERC, 2016) chose to adopt the CERC's approach of granting compensatory tariff. Like CERC, after concluding that no relief is possible under the PPA, the commissions were using their regulatory powers to bailout

12. As an example, in 2008 the MSEDCL signed a PPA for 680 MW at a levelised tariff of ₹ 2.70 per unit with M/s Lanco Kondapalli Power Ltd. under case-1 bidding. The project was supposed to be commissioned in 2012. However, no progress has been reported, and it is not clear whether the MSEDCL is exercising its legal rights under the PPA to protect itself from the possible adverse outcome of the delay in commissioning or the possibility of the capacity not materialising at all.

projects. However, as a result of the ATE judgement, these rulings would become infructuous and the generators will need to file fresh applications seeking limited relief that has been allowed by the tribunal. Thus, apart from protecting sanctity of contracts, the ATE judgement has also ensured that the regulators do not overstep their mandate. This is a major boost for the sector ridden with arbitrary post-facto contract changes.

Meanwhile, the tribunal's ruling on the issue of the applicability of force majeure has been challenged before the Supreme Court by the distribution companies and consumer representatives[13]. Similarly, the generators have also challenged the judgement contesting the ruling regarding lack of regulatory power to alter discovered tariff, and the finding that the promulgation of the Indonesian regulation and amendment of the New Coal Distribution Policy do not constitute change in law events.

Upon hearing the matters, the Supreme Court did not stay the proceedings before the CERC; however, it stated that "The order passed by the CERC shall be produced before this Court on the next date of hearing. It is made clear that the order passed by the CERC shall not be given effect to, without getting permission from this Court" (Supreme Court of India, 2016).

Pursuant to the directions of the Supreme Court, the CERC on 7th December 2016 issued orders computing relief as per force majuere provisions of the PPA for Tata and Adani Mundra Projects. The relief computed by CERC in the December 2016 order is lower by around 40%-50% compared to the compensatory tariff it had allowed in 2014. Additionally, the CERC has also disallowed any carrying cost to be considered for the past period. The applicability of the CERC order is subject to the Supreme Court's ruling in this regard as the matter is sub judice.

The examples pertaining to selective use of regulatory powers to bailout projects, policy advice suggesting post-facto revision of discovered tariff, and the ambiguities in fuel allocation policy that remain unaddressed, indicate the range of governance challenges that the sector is still grappling with. It also exposes the limitations of the policy and regulatory framework in dealing with the core issues concerning

13. Distribution companies in Maharashtra, Punjab and Rajasthan have filed appeals before the Supreme Court challenging the ATE judgement. Similarly, Tata Power, which is the owner and developer of the Mundra UMPP, has also challenged the ATE judgement. Prayas (Energy Group) was one of the appellants in the proceedings before the tribunal and has also challenged the ATE judgement before the Supreme Court.

competition and creating a level playing field.[14] In light of these serious challenges, the Supreme Court decision becomes extremely crucial in terms of not just giving finality to the pending issues pertaining to the tariff of the concerned projects, but also to decide the course of regulatory and policy framework for implementing competition in generation, and the larger issue of sanctity of contracts, which also concerns many other sectors.

2.4.4 Changing the bidding guidelines to manage fuel related risks

In order to manage the coal related issues, the MoP modified the bidding framework to make fuel cost a pass through element of tariff. It argued that "Since the risk of variation in fuel price cannot normally be managed by the Supplier, it must be passed on to the Utility, which, in turn, will have to reflect it in the distribution tariff. …Fuel Charge cannot be a profit centre for the Supplier and the principles for determination of Fuel Charge must ensure that costs are recovered on the basis of actuals, assuming that the Supplier would function with the efficiency expected of a prudent and diligent operator (sic)" (MoP, 2013). Accordingly, the guidelines for case-1, case-2 and UMPP projects have been changed[15].

It is important to note that even the earlier guidelines under which capacity of more than 42 GW has been added, did not in any way compel the generator to assume fuel related risks. It gave the bidders the flexibility to choose the level of risk they wanted to assume. However, mandatorily passing on the fuel risk to the consumers takes away any incentive for the generator to optimise fuel cost. In fact bidding based tariff discovery was insisted upon in the first place to overcome this short coming. Also, the assumption of the ministry that it would be possible to ensure that supplier operates efficiently and prudently, belies the regulatory experience of failure in controlling costs for regulated projects, which operate on the same principle.

Thus, it is unfortunate that instead of using the bidding experience and challenges as an opportunity to improve the coal sector governance and to streamline fuel allocation processes, the government chose the *easier* option of passing on all the fuel related risks to the electricity consumers.

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14. Chapter 5 on the distribution sector deals with this issue of regulatory effectiveness in more detail.

15. All the amendments to the bidding guidelines and the modified bidding documents are available on the MoP website http://powermin.nic.in/en/content/Electricity-Act-2003.

2.4.5 Issues pertaining to gas based capacity

One of the major criticisms of the 1992 IPP policy was its undue encouragement for LNG based generation, which was both expensive and uncertain given the fuel availability issues (Phadke, 2001). A large number of MoUs were signed for imported gas based projects although a cheaper option of utilising domestic coal was available. While many of these projects did not materialise, the ones that did became stranded for want of fuel. Importing gas was an expensive option and most SEBs could not have afforded to pay for such power. As such, the pace of gas based thermal capacity addition slowed down abruptly.

Following this, the developments in the domestic gas sector that led to claimed discovery of gas in the Krishna Godavari basin resulted in a renewed interest in gas-based generation. However, this too was short lived as the promised discoveries failed to result in actual production.[16] As a result, a large part of the gas-based capacity continued to be stranded and uneconomical.

The total gas-based installed capacity in the country is about 24 GW. Out of this 24 GW, roughly 14 GW has been totally idle while the remaining 10 GW has been running at an average load factor of 32%. Out of the stranded capacity of 14 GW, roughly 10 GW or more than 70% is owned by the private sector, while out of the capacity that is running, only 3 GW i.e. around 30% belongs to private sector (MoP, 2015).

In a recent development pertaining to the central government's efforts of reviving the stranded gas-based capacity, the MoP has introduced a scheme whereby such stranded capacity can be utilised for generating power at subsidised rates by using imported spot R-LNG (regasified liquefied natural gas) for FY 2015–16 and 2016–17 (MoP, 2015). Under this scheme, plants which could generate maximum power at minimum subsidy were to be selected through a bidding process.

As per news reports, a total of 15 projects of developers such as NTPC Ltd., Gujarat State Electricity Corp. Ltd., Torrent Power Ltd., CLP India Pvt. Ltd., GVK Industries Ltd., Lanco Kondapalli, GMR Energy Ltd. and Ratnagiri Gas and Power Pvt. Ltd. were shortlisted for receiving this subsidy in the first round. In the second round, 13 projects with an installed capacity of 8 GW have been shortlisted for receiving subsidy. The subsidy support for these projects would come from the Power System Development Fund (Bhaskar, 2015).

16. The issues pertaining to gas auctions and production are dealt with in Chapter 7.

Thus, since 1992, there has been an emphasis on gas based generation on account of its desirability as a peak source and also due to the problems related to availability and quality of domestic coal. It is also seen as a cleaner fuel. However, the experience of the past two decades shows that economics of LNG based generation remains questionable to say the least.

2.5 Issues pertaining to regulated (cost-plus) capacity

While competitively bid projects so far have ended up in serious post-bidding litigations, there has not been too much to showcase in terms of success or performance improvements for the regulated 'cost-plus' projects either. The tariff for regulated capacity is decided as per Sections 61, 62 and 64 of the Electricity Act 2003. All 'prudent' costs *plus* a regulated post-tax return of 15.5% (plus 0.5% for timely completion) is allowed for such projects (CERC, 2014a). Regulatory commissions, based on respective tariff regulations, stipulate performance norms and determine the tariff for each regulated plant and unit. It was expected that being a transparent and independent body, the commissions will decide performance and tariff of generating stations on sound techno-economic reasons and this will significantly improve the sector efficiency. While the issues regarding independence and autonomy of the commission are dealt with separately in Chapter 5, it is instructive to see how the commissions have dealt with the challenge of performance regulation in thermal generation.

2.5.1 Role of the regulatory commissions

Fuel cost accounts for more than 60% of the thermal generation tariff. Heat rate, an efficiency indicator for thermal generation, is among other things, also a function of coal quality. The higher the heat rate, the greater is the total generation cost. Even a 1% improvement in the heat rate of a power plant will reduce the total cost of generation by 0.4% and coal use by 3% (Chikkatur, et al. 2007). Lower heat rates are also desirable on account of correspondingly lower emissions and pollution. The regulatory commissions while setting performance norms for generating stations also specify the heat rate that the plant or station should operate at.

Poor quality or inadequate supply of domestic coal increases the fuel cost on account of coal imports while also contributing to deterioration in the heat rate. Coal being a central sector monopoly, generators often claim that they are unable to ensure good quality adequate supply of coal. Coal price is also deregulated and opaque. As a result, generators blame the coal supply for many performance issues and

also cost variations. However, for this to be established, there needs be clear data regarding how much of the increase in the fuel cost can be attributed to variation in the quantity and quality of coal. Commissions have found it to be very difficult to hold generators accountable for their performance. The developments pertaining to performance norm revisions for the stations operated by the Maharashtra State Power Generating Company Ltd. (MSPGCL) serve as a good case study to appreciate the difficulty in regulating thermal capacity.

2.5.2 MSPGCL performance regulation — a case study

After formulating tariff regulations and performance norms for all the generating companies in the state in 2005, the MERC issued the first multi-year tariff order for MSPGCL in April 2007. Through the said order, the MERC disallowed certain costs claimed by the MSPGCL, including those pertaining to transit loss of coal and station heat rates. In its submission before the MERC with regard to these cost heads, the MSPGCL claimed that:

> "MSPGCL submitted that it has no control over pilferage, loss during transit from colliery to the power station boundary and that the major scope of reduction in transit losses rests with Railways. However, MSPGCL has to the extent possible, already implemented initiatives to curb the losses. MSPGCL also submitted during the hearing that the entities responsible for transit of coal, i.e., Railways and Coal Companies are unregulated, and hence it is very difficult to make them comply with strict norms. MSPGCL has no option but to utilise their services" (MERC 2007)

Citing its 2005 tariff regulations and highlighting the need for efficiency improvement, the MERC did not consider the MSPGCL claims regarding fuel cost variations on account of deviation from actual performance parameters. The MERC had already noted that "SHR estimates of MSPGCL are not accurate to be considered for any review. The SHRs as estimated by MSPGCL are derived figures and their accuracy is influenced by the accuracy of measurement of the quantum and quality of coal used. The Commission has already issued clear directives for ensuring reliable and scientific measurement in this regard and has given sufficient time to MSPGCL. However, MSPGCL has failed to respond so far and the measurement of coal weight and calorific value continue to be simplistic and far from scientific. The Commission therefore does not see any sufficient reason to consider a review of the approved SHRs" (MERC, 2006, pp. 12,13).

Aggrieved by the order of the MERC, the MSPGCL challenged the same before the Appellate Tribunal for Electricity (ATE). The ATE noted that the main argument of the MSPGCL is that station heat rate targets given by the MERC are not achievable keeping in view the vintage, machine characteristics, quality of coal, and operating conditions. The ATE observed that:

> *"…if the SHR allowed by the Commission is not achievable, then the same would not be in anybody's interest; entity would suffer by not recovering its reasonable cost of supply of the electricity and the consumers would not get the right signal about the pricing of the product they would be using."*
>
> *"Under the circumstance, we feel that the Commission either on its own or through the Appellant engage appropriate independent agency(ies), who can carry out a study in a time bound (preferably within three months) manner to reasonably assess the achievable SHR of the plants owned by the Appellant. Such agency may also be asked to suggest measures to improve the SHRs over a period of time."* (ATE, 2008, p. 15)

Following the ATE judgement, the MERC in November 2008 appointed the Central Power Research Institute (CPRI) to carry out a detailed study to assess the level of achievable technical performance for all stations of the MSPGCL, except the newly installed 250 MW units. One of the main objectives of the study was to identify specific measures for improving heat rates. After inspection, the CPRI observed that none of the generating stations had accurate and/or reliable systems for monitoring unit level coal consumption. The report observes that in the absence of such measurement at the unit level, it is not possible to accurately estimate specific fuel consumption, which is the basis for heat consumption at the unit level. More importantly, there were issues pertaining to transit loss, coal quality and quantity. However, there was no data to precisely identify problem areas. In this context, the findings of the CPRI study are quite telling. The most important observations of the report are with respect to measuring transit loss and coal quantity at both station and unit level:

> "The technology of computing transit loss is obsolete and involves analog outdated machinery and manual recording at several places and also double recording resulting in wastage of manpower for recording purposes when it can easily be automated. Manual intervention increases chances of errors which are difficult to track and reconcile"

Similarly, under Section 2.3 dealing with unit coal measurement, the report states:

> "At present *no authentic on-line or off-line coal monitoring of unit coal consumption is available and the coal consumption is estimated by apportioning on the basis of units generated and coal factor.* … Most TPS are not having complete gravimetric feeder set up on any Unit with provision for coal flow measurement. *Further the quantum of consumption is not known accurately.*"
>
> *"In the absence of coal measurements to individual units, it is not possible to know the specific fuel consumption which is the basis for the heat consumption of the unit. The present system is highly inadequate and not sufficiently sensitive to unit performance. Hence, the estimated specific coal consumption does not reflect on the realistic coal consumption of any particular unit in question*" (emphasis added) (CPRI, 2009, pp. 4, 5).

In light of these findings, the CPRI made various recommendations to both measure and quantify coal related issues and to improve plant performance. The recommendations were grouped into three categories; immediate term — 12 months, medium term — 2 to 3 years and long term — over 3 years. Some of the immediate and medium term measures did not entail any additional capital expenditure. Following the study, the MERC revised the performance norms for the MSPGCL and adopted the norms suggested by the CPRI. However, the MSPGCL again refused to be accountable for its performance. In its submission before the MERC in the subsequent tariff petition for FY 11–12, the MSPGCL argued that:

> "…the need of commercial independence of MSPGCL should be factored while suggesting the SHR based on the recommendation of CPRI."
>
> "MSPGCL believes that it should have the independence to undertake its own due-diligence in selection of schemes in the overall interest of the consumers. And accordingly requests the Commission not to consider the CPRI recommendations in such binding manner." (MSPGCL, 2012)

Having undertaken an independent evaluation of realistic and achievable performance norms, the MERC revised the fuel cost for MSPGCL in accordance with the CPRI study. Once again the MSPGCL challenged the MERC order and the ATE ruled as follows:

> "In our opinion, reasonable time has to be given for completion of the medium term measures required for improvement of the SHR.

> The improvement due to operational/management practices has been accounted for in the SHR determined for 2008-09 and 2009-10 but for further improvement a reasonable allowance for gestation period for implementation of the medium term measures would be required to be given. It is pleaded by the appellant that some of the schemes for efficiency improvement have been under consideration of the State Commission. Accordingly, we direct the State Commission to reconsider the Station Heat Rate for FY 2010-11, taking into account the gestation period required for carrying out the medium term measures and re-determine the fuel cost for FY 2010-11" (ATE, 2011, pp. 26,27)

The ATE ruling effectively forced the commission to re-assess the MSPGCL's performance norms. The MERC again appointed the CPRI to assess the implementation of measures and suggest the revised performance trajectory, and the CPRI submitted its report in February 2012. The 2012 norms were closer to the actual performance of the MSPGCL in the preceding years.

While the CPRI study and its finding are specific to the generating stations in Maharashtra[17], the issues are symptomatic of the challenges entailed in regulating cost-plus capacity. Thus, the MSPGCL case highlights that simply having data and information regarding performance issues is not sufficient, and unless there is a strong will on the generating company's side to improve its performance, the regulatory process can only prevent or delay extremely bad outcomes. On its own accord however, the regulator, even when it is equipped with data and strong evidence, may find it very challenging to improve operational efficiency. The inter-linkages of the thermal sector with a closed sector like coal only add to the complexity of the task.

While the above issues are pertaining to fuel or variable cost, there are significant concerns regarding fixed costs as well. Most of the upcoming projects (whether central or state owned and in some cases even privately owned capacity contracted under bidding) consistently fail to achieve commercial operation as per the plans. To take an example of Maharashtra, most of the capacity added by the Maharashtra State Power Generation Company Limited (MSPGCL) since 2007 has missed the planned date of commercial operation by at least two years (Chitnis and Josey, 2015). Because of this, the cost per MW measure for these units is much higher

17. It might be worth mentioning that in terms of installed capacity, the MSPGCL is second only to NTPC, and the MERC is one of more active and transparent regulatory commissions in the country.

than the benchmark rate for units of a similar size and type notified by the CERC. On account of delays, the Interest during Construction (IDC) component of tariff also increases. For instance, the Tamil Nadu Electricity Regulatory Commission in its suo motu tariff order has noted that more than 40% of the fixed cost is on account of IDC (TNERC, 2014). As a result of these factors, the fixed charge of the newly commissioned units is quite high (on an average more than ₹ 2 per unit). High fixed costs can have serious tariff implications if this capacity has to be backed down. Thus, even the cost-plus regulation approach has been mostly ineffective in reducing costs and/or improving efficiency.

2.5.3 Preference for power procurement on cost-plus basis

By an amendment of the National Tariff Policy dated 5th January 2011, the central government exhorted all the states to adopt a competitive bidding route for contracting all new capacity addition (GoI, 2011). Hydropower was excluded from such consideration on account of its unique nature.[18] However, most states decided that it is within their discretion to decide whether a cost-plus or a competitive bidding route is to be adopted for capacity addition. Notably, all the privately owned distribution licensees in Delhi (DERC, 2009), Kolkata (CESC) and Mumbai (MERC, 2013c) (TPC, 2015) have tied up power from their own sister companies at cost-plus tariffs instead of undertaking a bidding process.

In one such incidence, the Tata Power Company (TPC) owned distribution company in Delhi signed a power purchase contract with its own sister concern Maithon Power Limited under a cost-plus basis. The TPC had also filed a petition before the central commission seeking exemption from applicable requirement of the competitive procurement process under clause 5.1 of the National Tariff Policy (NTP). The central commission however directed the TPC to seek clarification in this regard from the Ministry of Power, which was not followed upon. Meanwhile the TPC, as a distribution company, approached the Delhi Electricity Regulatory Commission (DERC) for approval of its PPA with Maithon. The DERC approved the contract but this decision was challenged by Reliance owned distribution companies in Delhi before the Appellate Tribunal for Electricity (ATE). In this judgment, deliberating on the question of whether competitive bidding was the only route available to distribution companies for power procurement, the ATE ruled as under (ATE, 2010):

18. This issue is discussed in detail in the Chapter 3 concerning hydropower development.

"The State Commissions have been given discretionary powers either to choose Section 62, 62(1)(a) to give approval for the PPA or to direct the distribution licensee to resort to the Competitive Bidding Process as per clause 5.1 of the NTP read with Section 63 of the Act."

Aggrieved by this decision of the Tribunal, the Union of India has challenged this order of the ATE before the Supreme Court of India. A judgement is still awaited. While it continues to insist on competitive bidding as the route for capacity addition, as discussed earlier, the Ministry of Power has however revised the bidding guidelines to make fuel cost a pass through element.

In this context, the private sector's approach towards MoU or cost-plus based procurement of power by state distribution companies from NTPC is worth noting. Promoting competitive bidding based power procurement, the National Tariff Policy in 2006 had attempted to limit the period for which power procurement can happen through the MoU route or the cost-plus basis. In this regard, the policy notes: "All future requirement of power should be procured competitively by distribution licensees except in cases of expansion of existing projects or where there is a State controlled/owned company as an identified developer and where regulators will need to resort to tariff determination based on norms … *Even for the Public Sector projects, tariff of all new generation and transmission projects should be decided on the basis of competitive bidding after a period of five years or when the Regulatory Commission is satisfied that the situation is ripe to introduce such competition*" (MoP, 2006) (emphasis added).

As per the 2006 policy, the exemption for bidding granted to the public sector was valid up to 5th January, 2011 or when the concerned Regulatory Commission thought it was appropriate. The CERC Commission through statutory advices suggested to the MoP that "the deadline of January 2011 for completing the transition to procurement of power through tariff based competitive bidding even from State/ Government owned entities should not be extended any further." (CERC, 2010a, CERC, 2010)

Alleging that the NTPC undertook a massive exercise of signing PPAs for more than 37,000 MW of capacity with the state distribution companies with a clear intention of bypassing the impending bidding requirements, the Association of Power Producers (APP)[19] filed a case before the CERC challenging the same as abuse of monopoly

19. More details regarding the association can be found at http://appindia.org.in/.

power by NTPC. The APP also claimed that the NTPC had already signed PPAs for 9000 MW between April 2010 and September 2010, thus bringing the PPAs signed during 2010–11 (up to 5th January, 2011) to about 47,000 MW.

Observing that the allegations regarding abuse of monopoly power by the NTPC are mere "surmises only without being supported by hard evidence", the CERC noted that "it is on record that during the period 5.1.2006 to 5.1.2011, the members of petitioner's association have contracted 1,05,324 MW of electricity as against 52,605 MW contracted by NTPC during the corresponding period." (CERC, 2013) The CERC dismissed the APP petition for lack of merit.

It is interesting to note that the generating companies like Tata Power, Reliance Power, Torrent Power, etc. as members of the APP challenged the state DISCOMs' decisions to sign cost-plus PPAs with another state owned entity such as NTPC, claiming that such actions deny to them the opportunity to compete. However, when acting as distribution companies, these same entities have avoided competitive procurement of power and have insisted upon signing cost-plus PPAs with their own sister concerns.

2.6 Conclusion and lessons

The 1992 IPP policy was launched with the main objective of bringing in additional private (and preferably foreign) investment in the sector. These efforts largely failed because, though a large number of MoUs were signed not much capacity was actually added. Given the serious lacunae in the IPP policy, if even the eight fast-track projects, let alone the 137 for which MoUs were signed, had actually materialised based on the terms envisaged under the MoUs, not only would the SEBs have become bankrupt, but on account of the sovereign guarantees, even the state and central governments would have been under severe stress.

Since the opening up of the sector, one of the major policy objectives was to bring in private and foreign investments and to free the government's scarce resources. However, Indian public financial institutions have financed a majority of the thermal capacity that has been added till date (RBI, June 2015, p. 15).

Learning from the IPP policy failure, the competitive bidding framework under the Electricity Act of 2003 was a promising new start with significant process and governance improvements. As a result of it, the last decade witnessed an unprecedented growth in coal based thermal capacity with the private sector

adding more than half of it. As of December 2016, the 12th five year plan target of 88 GW of capacity addition from conventional sources was already met and is even likely to be exceeded (CEA, 2016b, pp. 2.3).

A large part of the capacity added by private sector is under the competitive bidding framework. Bidding also seemed to lead to economical discovery of tariffs. However, given the post-contract litigation seeking tariff revision, the efficiency gains from bidding remain uncertain. The UMPPs, which were the flagship projects that were believed to be the torchbearers for demonstrating the potential of competition in reducing tariffs and improving efficiency, are poised to either turn into 'cost-plus' projects[20] or non-performing assets. This is indeed a serious lesson that merits serious rethinking of the prevalent policy approach.

During the IPP era, there was no publicly available data regarding the MoU projects. This had serious consequences for the project selection, choice of fuel, tariff, etc. It is disturbing to note that even after more than a decade since the introduction of competitive bidding guidelines, there is still no public database that records the exact status and details such as the PPA, tariff, regulatory approvals and other statutory clearances, of all the competitively bid projects. This is in spite the need for such a common data repository being highlighted time and again (Gadag, Chitnis and Dixit 2011, MoP, 2011b). Lack of such crucial data in public domain creates serious issues in terms of power purchase planning, financing and also managing scarce interlinked resources such as fuel, land and water, which many unviable projects may lock in for long periods.

In spite of the obvious connection, little attention has been paid to integrate the coal and thermal power sectors. After opening the generation sector in 1992, it took the policy makers almost fifteen years to formulate the first coal distribution policy. Even this formulation was at the behest of the directions of the Supreme Court, arising from a dispute, and did not provide any concrete path for the coal allocation itself. It merely promised to make an *endeavour* to supply domestic coal *as much as possible* and indicated that the shortfall would be met through imports – price of which would have to be borne by the coal buyer. More than three-fourth of the capacity added through the bidding route was based on such 'assurance', and as soon as contracts were won, generators were seeking tariff revision citing coal

20. If the compensatory tariff as demanded by the projects is allowed, it will essentially take away all the commercial risk pertaining to fuel price variation, which in the first place was willingly assumed by the project developer to win the bid, and thus make the energy charge determination an essentially cost-plus exercise.

supply related issues. The banking sector, which should not have financed such risky ventures, provided lending to the projects and later sought bailouts. In spite of the serious due diligence failures, the bankers have not taken any hit, which means that the moral hazard and hence public sector lending to projects based on risky fuel arrangements would continue.

Financial capacity of the distribution sector, which is the main buyer of the power, continues to be very weak. The accumulated losses of distribution companies are estimated at over ₹ 3 lakh crores. Without major changes towards scientific demand estimation, capacity addition planning and market based instruments; many states could end up with high cost surplus power[21], and simultaneously a huge unmet and latent demand. With the carriage and content separation being proposed under the amendments to the Electricity Act (MoP, 2014), and a strong policy push for renewables[22], the issue of need and demand for thermal base load capacity has become even more complex. Considering that hydropower and gas based thermal generation, the standard choices for peak management, are unlikely to take off in the near future, the issue of managing intermittency and peak demand becomes critical. It will be further accentuated if the ambitious renewable energy capacity addition targets are actually met. If coal based thermal generation is to be utilised for managing variability, the issue of its pricing becomes even more crucial. Currently, there is no mechanism to address this.

One of the crucial flaws in the IPP policy was its lack of consideration for the demand for power. This flaw has continued to remain unaddressed even in further policy formulations, as the bidding guidelines also do not require the procurer to undertake a rigorous demand assessment (MoP, 2007). According to the draft National Electricity Plan 2016 published by the Central Electricity Authority "no coal based capacity addition is required during the years 2017-22." The CEA further notes that "…as coal based capacity of 50,025 MW is already under construction which is likely to yield benefits during 2017-22, this coal based capacity would fulfil the capacity requirement for the years 2022-27" (CEA, 2016b, p. xxv). The fact

21. Distribution utilities routinely curtail demand by either shedding load and/or managing agricultural demand. Based on revenue considerations, these companies can choose to not supply power to certain areas or category of consumers. Presently, there is no accountability mechanism to regulate and monitor actual supply hours and hence the utilities can claim to be surplus and also undertake load shedding simultaneously, without facing any regulatory action.

22. There is already a plan and policy commitment to have 175 GW of renewable energy based capacity by 2022. Additionally, as per India's Intended Nationally Determined Contribution submitted to UNFCCC, 40% of India's installed capacity in 2030 is going to be from non-fossil fuel based energy sources.

that a significant amount of stranded capacity exists and that thermal capacity in the pipeline is already more than what is needed for the short and medium term, clearly indicates a failure to factor in demand for power in a rational manner and also importantly, limitations of an approach just aimed at attracting investments in the sector.

In case of lack of demand, we will not only face challenges of stranded assets and other associated economic burdens, but we would have also locked-in critical and scarce natural resources, which otherwise could have been put to better public use. It is important to note that any proposed capacity addition has linkages with not just the real demand for power, but also with resources such as land, water and fuels. Given our poor track record in dealing with the issues concerning environment as well as displacement and associated social issues, it is extremely important to set governance processes to evaluate not just the need and economic viability, but also the social and environmental costs of setting up any new capacity. For this purpose, interventions are required to develop the criteria for minimising cost not just for the power sector, but also to minimise social and environmental impacts, and to make optimal use of water, land and other natural resources.

Thus, in the short term to medium term (2022-2027), the challenges before the thermal generation sector are less of availability, and more of affordability, sustainability and viability. Given this situation, if new investments are made in the thermal sector, there is a high possibility of a lock-in of such investments in the medium term[23]. Therefore, it would be more prudent to first maximally utilise all the existing (stranded) capacity and to carefully allow further capacity addition only after this has been fully achieved and if still further thermal capacity addition is warranted.

23. Projections regarding thermal capacity addition would affect coal production targets and the two should be decided in tandem with each other.

3
Reforms in hydropower: Missing the woods for the trees

"We cannot solve our problems with the same thinking we used when we created them."

- Albert Einstein

3.1 Introduction and overview

The earliest power sector reforms were centred almost exclusively on generation and included hydropower as one of the key focus areas. Apart from hydropower bringing additional generation capacity, it was also considered important from several other perspectives.

Hydropower has been described by the government as a cheap, renewable and environmentally friendly source of electricity[1], though each of these claims has been challenged. It has also been considered the best choice for meeting peak load demands.[2] Its "inflation free" characteristic is also an attribute in its favour. This last refers to the fact that once a hydropower plant is installed, with the initial outlay, there is limited expense in running it with expenditure only for operation and maintenance, as it has no fuel costs. This means that the cost of power from it does not increase with increasing fuel costs in the future.

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1. For example, see Introduction to the Hydropower Policy 2008, Government of India, (GoI, 2008) by the then Minister of State for Power, Shri Jairam Ramesh.

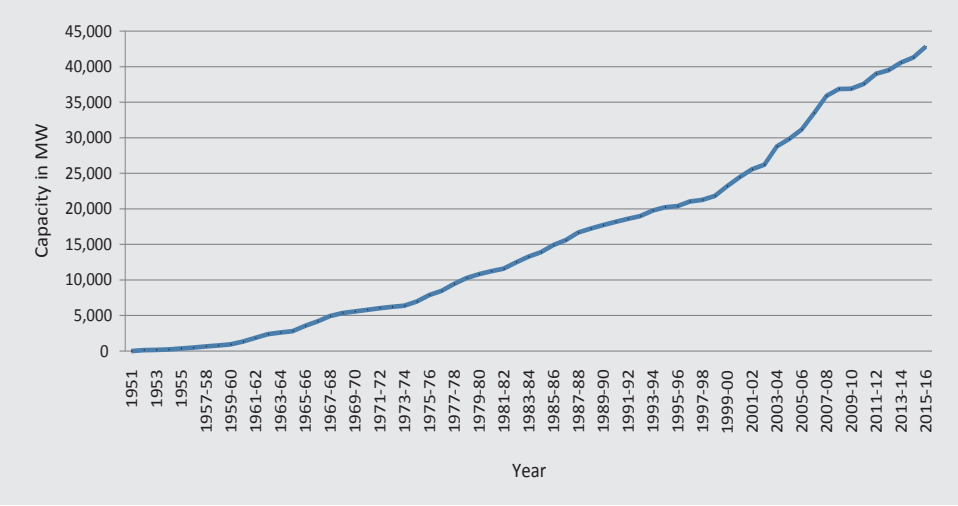
2. Peak load refers to the sudden surge in demand for electricity, for example in the evening when most houses switch on lights. Meeting this demand can be difficult for generating units like coal-based power plants as they are not able to ramp up their generation in a short period. Hydropower is considered one of the ways of meeting such peak demand as it can ramp up generation in virtually no time at all. This is of course, provided it has water available to release at that time. This can be a problem with run-of-river hydropower projects.

At the same time, hydropower projects have immense social and environmental impacts, displacing communities, submerging lands and forests and disrupting rivers. They also have high capital costs, construction takes a long time, and involves high levels of uncertainties due to geological and other problems.

3.1.1 Introduction to the hydropower sector

The total hydropower potential in the country has been estimated to be around 150,000 MW out of which close to 41,000 MW has been installed. Figure 3.1 below gives the development of hydropower capacity in the country over the years.

Figure 3.1: Installed hydropower capacity in India from 1951 to 2016

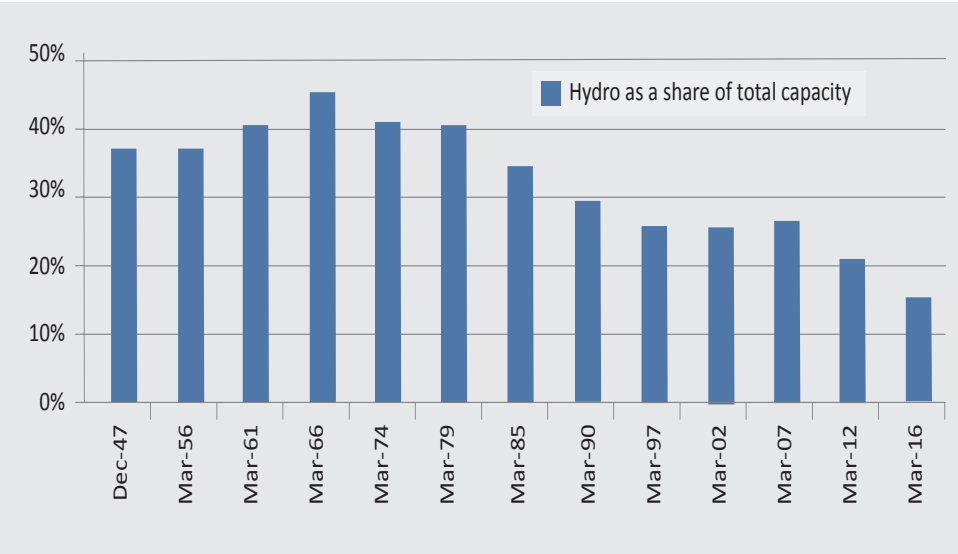


Source: (CEA, 2016c).

Concern is often expressed in official circles about the low pace of creation of hydropower capacities, and the declining share of hydropower capacity as a percentage of total capacity (See Figure 3.2). Because of this, reforms in the hydropower sector, while focussing a lot on incentivising private players, have also tried to deal with removing impediments to the development of hydropower in general including by the public sector.

Much of the hydropower capacity installed till recently was as part of multipurpose projects that also cater to other needs like irrigation, rather than standalone hydropower. Most of India's remaining hydropower potential is in the northern and north-eastern Himalayan states.

Figure 3.2: Hydropower capacity as a percentage of total installed capacity in India from 1947 to 2016



Source: (CEA, 2013; CEA, 2016a).

3.1.2 Reforms in the hydropower sector

Reforms in the hydropower sector began in 1991 against this specific background as well as the concerns prevailing in the power sector at large. At the end of March 1990, the installed hydropower capacity was around 18,000 MW, and this constituted 29% of the total generating capacity at that time. As noted earlier, creating more capacity was the key focus then, and even though there were many other issues to be addressed, when the reforms were initiated, they were dominated by this one concern. Even in terms of creating more capacity, the focus was essentially on privatisation — getting the private sector to build new generation capacity. Indeed, it would not be wrong to say that this was almost the sole thrust of the initial phase of the reforms. This was because the problem was diagnosed as that of lack of resources with the government to invest in infrastructure creation. The aim therefore was to get the private sector to bring in the investments, and for this, a host of incentives were provided, and laws and regulations were changed to make it possible for the private sector to develop generation projects. (See Section 3.2 for more details.)

These incentives and policy initiatives were hugely successful, at least on the face of it. There was a spree of Memoranda of Understanding (MoUs) being signed and

some 243 MoUs for over 90,000 MW of capacity (hydel and thermal) were signed with private developers over the next few years.

Table 3.1: Current status of private hydropower plants from the first group of projects post-1991 liberalisation that had obtained in principle clearance from the CEA

Sr. No.	Name of plants in the first post-1991 liberalisation lot that got CEA in-principle clearance	Capacity (MW)	Date of commissioning	Remarks
1	Malana	86	2001	
2	Allain Duhangan	192	2010–11	
3	Karcham Wangtoo	1000	2011	
4	Uhl-III	100	Under construction (2017–18)	Now in the public sector (state government)
5	Dhamwari Sunda	70	Status not clear	
6	Hibra	221	2012	Now in public sector, executed by NHPC, renamed Chamera-III
7	Baspa-II	300	2002–03, 2003–04	
8	Vishnu Prayag (400)[3]	400	2006–07	
9	Almatti (1107)	1107		Only 290 MW commissioned, in public sector (state government)
10	Shrinagar	330	2015[4]	
11	Maheshwar (400)	400	Not commissioned	Now taken over by the public sector
12	Tawa LBC	12	Status not known	
13	Karbi Langpi	100	2006–07	Now in the public sector (state government)
	Total	4318		

Source: CEA Status of HEPs (CEA, 2014), CEA Progress of On-going Hydro-Electric Projects (CEA, 2016c).

3. This project was severely affected in the 2013 Uttarakhand floods and also had severe downstream impact. The Shrinagar project at Sr. No. 10 in Table 3.1 was impacted similarly.

4. As per CEA Quarterly Progress Report No. 82, (CEA, 2015).

3.2 Lukewarm response of the private sector in hydropower

There are indications that the majority of these 243 schemes for which MoUs were signed with the opening up of the power sector in 1991 were thermal, though the exact distribution is not clear. Among the entities that signed MoUs for hydropower, many did not even proceed to obtain the required first stage in-principle clearance from the CEA (GoI, 1997). Only 13 schemes with a total capacity of 4,318 MW had obtained in-principle clearance by 1996 (Central Board of Irrigation and Power, 1997). Table 3.1 shows the status of these 13 projects today.

Thus, apart from the fact that only a few hydropower projects were taken up by private developers in response to the reforms initiative, even the implementation of these projects was not as per expectations. As Table 3.1 shows, progress on the 13 projects that had obtained in-principle clearances in 1996 has been mixed, with several projects not yet being commissioned, and several being commissioned by public sector enterprises rather than the private sector, which was the primary aim of the policy initiatives in 1991.

In fact, even in the years following the first phase of reforms, the response of the private sector to hydropower remained poor, and till date, private hydropower projects constitute a minor part of the entire installed hydropower capacity in the country. Since 1991–92, about 24,000 MW of hydropower capacity has been added in the country, but only 3004 MW of this (~12%) has been in the private sector. Thus, the apparent success of the 1991 policy was, in the case of hydropower, just that — apparent.

Table 3.2 lists all the private sector hydropower projects in the country. To clarify, these include the private projects built in the pre-1991 reforms era, namely Bhira (1927, 1950), the projects from the 13 private projects in the initial phase of reforms (those listed in Table 3.1), as well as some more private projects that were built in the subsequent phases of the reforms. All these projects have been commissioned after 1991, except Bhira (1927, 1950).

Table 3.2: Commissioned hydropower projects (private) as on 31st March 2016 (capacity >25 MW)

Name of Company	Name of Project(s)	State	Capacity
MPCL	Malana	H.P.	86
EPPL	Malana-II	H.P.	100
ADHPL	Allain Duhangan	H.P.	192
JSW Energy	Karcham Wangtoo, Baspa-II	H.P.	1300
JPVL	Vishnuprayag	Uttarakhand	400
TATA HYDRO	Bhira, Bhivpuri, Khopoli, Bhira PSS	Maharashtra	447
DLHP	Bhandardhara –II	Maharashtra	34
GIPL	Chujachen	Sikkim	99
DEPL	Jorethang Loop	Sikkim	96
AHPC	Shrinagar	Uttarakhand	330
Greenko	Budhil	H.P.	70
Total			3154

Source: (CEA, 2016b), date of commissioning as per (CEA, 2014).

3.2.1 Reasons for the dismal performance of private hydropower

On 26th August 1996, the Ministry of Power, Government of India set up a committee headed by former Chairperson of the CEA, Shri M.K. Sambamurti, for "promotion and development of hydroelectric projects in the private sector". Analysing the reasons for the lukewarm response of the private sector, the committee placed it in the context of the overall decline in the growth of hydropower in the country, including public sector hydro projects. The committee report notes that "hydropower development had a serious setback in the Fourth Plan (1969–1974) and it never recovered from it" (GoI, 1997, p. 6)

The committee identifies three main reasons for the slowdown in the pace of growth of the entire hydropower sector, some of which were also applicable to the lack of response of the private sector. The first and most important is noted as the "constraint of financial resources". Since this is the very reason for trying to get the private sector into hydropower development, it does not explain their lack of response. The second reason is stated as *"the shift of the scene of hydropower development from geologically simpler peninsular India to the geologically most uncertain and complex young mountain terrain of Himalayas" that has had "serious*

repercussions and implications of far-reaching consequences." The difficult geology in the Himalayan area can not only increase the cost of building projects there, but has the potential to spring more "geological surprises" that can make calculations of costs and time go haywire. Lastly, the committee also notes sustained attacks and criticism of the environmental impacts of hydropower projects from environmental activists (GoI, 1997, pp. 8,9).

Of course, these factors were very much present and known when the sector was opened up for private sector participation. However, these factors were not taken into consideration in framing the policies, which tended to focus mainly on the financial aspects, aiming to provide an "attractive" return to the investors. The underlying assumption seemed to be that this return would be sufficient to attract private investment into the hydropower sector.

Other than these generic issues, but related to them, was an important argument put forth by several people, and also reflected in the Sambamurti Committee's report: that the incentives offered to private players were not found attractive enough by developers. In an article dated 10th February 1998 in the International Water and Power magazine, I.M. Sahai (Sahai, 1998) writes:

"The main reason for IPP disinterest was that the hydropower policy of the then federal government, evolving through a process of trial-and-error, did not adequately answer certain key concerns of the hydropower developers. This was especially seen in the hydro tariff formula, which the government took its own time to specify, completing it in January 1995."

The Sambamurti Committee had noted in 1996 that, after the 1995 hydro-tariff formula was in place, more incentives were needed for private hydropower players. It recommended that "there is a case for raising RoR (rate of return) for hydro projects to bring them on par with thermal power projects" and that "the power plants providing peak power … can be allowed an additional return on equity" (GoI, 1997, p. 39).

Along with the argument to further enhance the returns to the project owners, it was argued that risks for developers be reduced. Again, the Sambamurti Committee reflects this, recommending that "due to long gestation period and many uncertainties involved, hydro projects… do not find favour with the lenders. To start with, therefore, the hydro projects which involve lesser risk element and entail lesser capital investment should only be considered for development in the private sector" (GoI, 1997, p. 44).

Lastly, with respect to social and environmental implications, the Sambamurti Committee suggested that since the environmental implications of the CEA's hydroelectric survey had not been fully studied, "it is necessary to undertake a preliminary environmental impact study of the schemes identified… and select schemes which will involve least environmental impact. Then these can be pursued vigorously while the others are subjected to more detailed environmental assessment." While this was an important recognition of a major issue, it somewhat naively recommended entrusting the exercise of carrying out impact assessments to the CEA/CWC, whose core competencies certainly did not include environmental impact assessments and mitigation. (GoI, 1997, p. 15). It further recommended that the state government, on behalf of the private developer, should take up works like land acquisition, rehabilitation and resettlement, and catchment area treatment.

However, the biggest issue facing the Sambamurti Committee was how to negotiate a private hydropower project so as to ensure that major risks of the private operator were covered, without allowing them to claim excessive and underserving costs. The tariff notification essentially provided for a cost-plus approach, that is, the private company would be paid (through tariff) all their costs and then profit and incentives over and above that. This had the clear danger of cost padding by the developer and needed meticulous oversight by the purchaser of power or regulator to ensure that unnecessary costs were not incurred, nor was there diversion of funds. Further, there had to be a way to compute the reasonable and fair cost of building the project.

Competitive bidding was the alternative route, in which the developer quotes the rate at which he is willing to sell the power and the procurer selects the least cost bid. Here, there is no need for the procurer to maintain any supervision of the project nor any need to calculate the capital expenditure of the project. However, the process of setting up competitive bidding can be complicated, requiring complex procedures and selection criteria particularly for projects in geologically difficult terrain, as these are affected by significant uncertainty.

This issue was particularly important as the hitherto followed route of individually negotiated MoUs was facing heavy criticism, as this was a non-transparent process, with many allegations of rent-seeking practices shaping MoUs and PPAs in favour of private parties. The controversy of the Enron project was raging at the time. It was alleged that large bribes had been paid to skew the PPA completely in favour of Enron, resulting in very high cost of power (See Section 2.2.3 in Chapter 2 for details of this controversy). The Sambamurti committee was quite unequivocal in

its findings in relation to the possibility of estimating the correct costs of a hydro project (GoI, 1997, p. 25):

"… accurate calculation of completed cost of hydro projects is complex as the cost is essentially dependent on site conditions rather than market conditions … The Committee is not aware of any mechanism existing anywhere in the world for a precise computation of costs of hydro projects and to unearth and reduce the inflated costs provided in the DPR as a cushion and as a source of extra profit."

Given that the completed costs of the projects are what are used to calculate tariffs under a cost-plus regime, it is clear that there is virtually no way cost padding can be controlled — or detected — in such hydropower projects. This should virtually rule out cost-plus as an approach. However, the committee still remained "ambivalent" in terms of which approach to recommend, possibly because they felt that "it's not certain whether it [competitive bidding] will attract adequate response" (GoI, 1997, p. 44)[5]. Instead, they suggested competitive bidding for smaller, less complex projects in geologically friendly terrain and an MoU procedure for larger projects in geologically difficult areas. They suggested that the licensor should have the freedom to choose the procedure in consultation with the CEA. They also said that whatever the procedure, "ultimately the success of the project… would depend on the earnestness of the parties concerned and the transparency of procedures followed." (GoI, 1997, p. 44)

Such strong findings of the Sambamurti Committee report raise the question as to whether hydropower can at all be opened to the private sector, particularly under the cost-plus tariff route. Moreover, the sum of the recommendations was that virtually all risks were to be taken up by the government, while the private sector was to be offered attractive incentives in return for their investment. Lastly, even with all these incentives, it was felt that the ultimate success of any route would depend on the "earnestness" of the parties involved and the transparency of the process — the former is difficult to evaluate objectively and the later was not adhered to. These factors should have raised questions not only about the feasibility of privatisation of hydropower, but also about its desirability. International experiences with reforms in the hydropower sector reflect these elements of the Indian experience, and for similar reasons. Details can be found in Box 3.1.

5. Albeit, looking mainly at the issue of working out the completion cost, the committee felt that where there is adequate competition, competitive bidding should be the preferred option ((GoI, 1997, p. 33), para 22).

However, the government remained firm on continuing its policy of incentivising private players to invest in hydropower projects.

3.3 Hydropower policy 1998

Based on the Sambamurti Committee report, the Government of India brought in a new hydropower policy in 1998. It talked about the importance of hydropower in the power sector, noted the "poor response of the private sector which may persist for some more years" (GoI, 1998b, p. 4), and hence mentioned that the public sector would continue to play a dominant role in the sector. At the same time, the policy reiterated the need to increase private investment since the hydropower sector would need "huge investments which are difficult to be supported from budget/ plan assistance ..." and that "required atmosphere, incentives and reliefs would be provided" for this purpose (GoI, 1998b, p. 5). One of the measures presented by the policy was the creation of a National Power Development Fund, which would be used to prepare fully investigated Detailed Project Reports (DPRs) of hydropower sites, obtain clearances, preferably undertake pre-construction activities and enabling works, and then offer these sites to the private developers.

The policy noted that the tariff norms for hydropower were viewed by both PSUs and IPPs as being unfavourable as compared to thermal power, and so the government had decided to "rationalise the existing hydro tariff norms, improve the incentives for better operation and evolve a solution to the contentious issue of computing the completion costs in face of geological uncertainties and surprises …" (GoI, 1998b, p. 14).

These measures included a premium on sale rate of hydro generation during the peak period, reducing the normative availability factor[6] from 90% to 85% especially in projects with silt-laden waters, and allowing the sale rate of secondary energy generation[7] at the same rate as primary generation. It also proposed the constitution of an expert committee to consider and recommend escalation in completion cost due to geological surprises. It is important to note that the policy decided to continue with the cost-plus approach to tariff determination.

6. Availability factor of a project is defined as the number of hours in a year, expressed in percentage terms, when the power station is ready and available for generating power in case water is available. The norm that is fixed for the availability factor by the concerned authority is the Normative Availability and was 90% at that time.

7. Secondary energy is the quantum of energy generated in excess of the design energy on an annual basis at a hydropower station. Design energy is the quantum of energy which can be generated in a 90% dependable year (which is effectively a measure of how much water is available in the river), with 95% availability of the installed capacity of the hydropower generating station.

In an important provision, the policy articulated a need to insulate project authorities from the problems arising out of land acquisition and R&R, and decided to put the responsibility for these processes on the concerned state governments. The thrust was clearly on providing more incentives and profits for the private player, and cut their risks. The latter was done primarily by the states taking up the responsibility for socio-environmental aspects and other risks inherent in the process.

Box 3.1: International experiences with hydropower reforms

A World Bank Discussion Paper (World Bank, 2000) which examines 10 private hydropower projects in 5 countries — Philippines, Lao PDR, Brazil, Nepal and Turkey — concludes that the number of successfully financed private hydropower projects has been very limited due to their capital intensity and complex risk profiles.

The study also lists various problems faced by the hydropower sector that are an impediment to private sector participation, and among these are "the site-specific nature of the projects, their high construction risk and relatively long construction periods …. the difficulty of achieving transparency in the award of concessions and the pricing of output and environmental sensitivities ..."

It states that "construction risks remain a serious problem for sponsors and contractors alike, particularly where there has been only limited site investigation."

The study acknowledges that competitively bidding a hydro concession is a complicated and costly process, and unless handled carefully, it may deter prospective sponsors. It notes that the ancillary benefits of hydropower are not given their due, and particularly there is "weak recognition of the premium value of peaking energy over base load." About environmental impacts, it implies that this is too big a responsibility for the private sector to handle and suggests that environmental clearance is a public responsibility that should be discharged before the private sector is involved. The study concludes that large projects may be viable only under some form of public-private partnership and interestingly notes that most of the projects studied would not have been financed without public sector support. The recommendations of the study essentially consist of policies that focus on increasing such public support, exposing the public sector to increased risks, and offering more incentives to private players.

While the study looks at experiences from the developing countries, it also says that "there is growing evidence, from the United States and elsewhere, that existing hydro will prosper in fully deregulated markets". However, the figures from the United States indicate to the contrary, and confirm the risk-averse nature of private hydropower developers.

According to a US Congressional Research Service Report of 2015 (Bracmort, Vann, & Stern, 2013), the private sector owns two-thirds of US hydropower plants but accounts for just over 25% of production capacity, while the federal government tends to own mostly large hydropower (> 30 MW) plants. The private sector and cooperatives tend to own mostly small hydropower (1–30 MW) and low power (< 1 MW) plants. The ownership-wise break up of hydropower plants in the US is given in Table 3.3, extracted from another report (Hall & Reeves, 2006):

Table 3.3: Ownership-wise break up of hydropower plants in the US

		Plants		Capacity	
		Number of plants	% of total	Total (MW)	% of total
Private	Private utility	735	31%	18209	24%
	Private non-utility	642	27%	1810	2%
	Industrial	226	9%	733	1%
	Cooperative	37	2%	331	0%
	Sub-total Private	1640		21083	27%
Public	Non-federal public	577	24%	16573	22%
	Federal	171	7%	37215	50%
	Sub-total Public	748		53788	72%
	Total	2388	100%	74871	100%

Source: (Hall & Reeves, 2006).

Indeed, the largest privately owned conventional hydroelectric project in the US is the 1,166-megawatt Hell's Canyon Project on the Snake river near Adam County, ID and Baker County, OR. The Idaho Power Company has operated the project for over 50 years (Hall & Reeves, 2006). Thus, the largest private capacity is significantly smaller than the largest non-federal, publicly owned conventional hydroelectric plant, the 2,755-megawatt Robert Moses-Niagara project, operated by the New York Power Authority, or the largest conventional hydroelectric project owned by the federal government, the

Grand Coulee project on the Columbia River in north-central Washington with a capacity of 7,079 megawatts. Thus, the experience of the US, which has significant private hydropower capacity, shows that private hydropower developers may not take up too many risks and tend to go with smaller projects.

Along with focussing on measures to encourage private developers, the government also increased its overall efforts to promote hydropower, even in the public sector. This included "mission mode" schemes like the 50,000 MW initiative, further changes in the hydropower policy and in general a continuation of the strategy to give more concessions to hydropower and reduce risks for developers.

3.4 The 50,000 MW initiative

The '50,000 MW Initiative' was inaugurated by then Prime Minister Atal Bihari Vajpayee on 24th May 2003. This initiative fast-tracked hydropower development by taking up time-bound preparation of the Preliminary Feasibility Reports (PFRs) of 162 new hydroelectric schemes totalling around 50,000 MW. These projects were to be completed by 2017.

However, the scheme has not lived up to its high ambitions even though the PFRs were completed ahead of schedule. The status as of 31st March 2016 was that the Detailed Project Reports (DPRs) are completed for a capacity of 21,317 MW, capacity of 2266 MW is under survey and investigation, and 24,347 MW is held up on account of proposed changes of agency or non-allotment, non-availability of MoEFCC clearance, or local agitations and other reasons. Only a few of the projects, totalling to 1633 MW, with DPRs completed are under construction.[8]

3.5 New hydropower policy 2008

In 2008, the Government of India came out with a new hydropower policy, whose main thrust and focus once again was inducing private investment in hydropower through provision of incentives.

While the earlier Hydropower Policy of 1998 had continued the cost-plus approach for tariff determination, after the enactment of the Electricity Act in 2003, the Tariff Policy of 2006 recommended that any power that the distribution utilities source

8. Status of 50,000 MW Hydro Initiative, as on March 2016, (CEA, 2016d).

from private generators, including hydropower, should be through competitive bidding. In fact, the 2006 policy also aimed at introducing bidding for all the power procurement from state and central utilities in a time bound manner (GoI, 2006). For details of the competitive bidding policy and its rollout, see Chapters 2 and 5 on thermal generation and distribution.

However, the National Tariff Policy was amended in 2008 to relax this requirement, and to exempt private hydropower projects from it[9], if they chose to opt for regulated tariff determined by the appropriate electricity regulatory commission and also qualify under few other conditions. They could now choose to get the tariff determined by the appropriate regulator based on their capital costs. It may be mentioned here that unlike thermal generation projects, it appears that none of the hydropower projects have till date participated in any competitive bid for power procurement.

The hydropower policy also allowed projects to sell up to 40% of their saleable energy on a merchant basis[10]. It justifies this by stating that "…from the point of view of the private sector the major incentive is the scope for trading — particularly in the later years when cost of generation goes down and the market price of power is high." (GoI, 2008, p. 4)

While the policy also had "improving resettlement and rehabilitation" (R&R) as one of its objectives, the related provisions in the policy fell far short of any meaningful and fair rehabilitation of the affected people. For one, the basis on which the policy hoped to address the issue of improvement in R&R was the National Resettlement and Rehabilitation Policy (NRRP) 2007 (Ministry of Rural Development, 2007). This essentially was an extremely weak policy with key provisions subject to many ifs-and-buts, which provided escape loopholes. For example, resettlement provisions included "land-for-land, to the extent Government land would be available in the resettlement areas; preference for employment in the project to at least one person from each nuclear family … subject to the availability of vacancies and suitability of the affected person ..." (Dharmadhikary, 2007).

9. Public sector projects were already exempt from this requirement.

10. Merchant power plants are power plants whose electricity generation, in part or full, is not tied up with any long -term power purchase agreements. Thus, they are able to sell their power under short term agreements, or in the spot market. This carries the risks and rewards of selling at market prices, depending on the prevailing demand-supply equation. In case of hydropower, there is an additional aspect. Since the main cost of hydropower generation is the financial investment, and there are no fuel costs, the cost of generation falls sharply after the capital costs are paid off. Once this happens, the sale of power at market price can bring windfall gains to the project developers.

The Hydropower Policy did urge the state governments to go beyond the provisions of the NRRP, but the actual decision was left to their discretion. It had also suggested a "package" for the liberalisation of R&R provisions, which itself was not much of an improvement. The Hydropower Policy also suggested some steps for benefit sharing. One of these measures was a Local Area Development Fund to be funded by the developer putting in 1% of the power generation and the states urged to put in a matching 1%, for "providing a regular stream of revenue for income generation and welfare schemes, creation of additional infrastructure and common facilities etc. on a sustained basis over the life of the project." (GoI, 2008, p. 36) Another provision was to provide for 10 years, 100 units of electricity per month to every affected family. Though welcome, both these provisions were not sufficient to address the fundamental flaw in the basic R&R package, that it did not provide a replacement livelihood or proper resettlement. Moreover, these provisions ignore the fact that the families that have lost land or livelihoods may have shifted away from the local area and hence would not benefit from the fund. The policy proposed to install all of India's hydropower potential (about 150,000 MW) by the year 2027 with about 81,000 MW expected to be installed at the end of the 12th Plan (2017).

3.6 Tariff regulations of 2009 and 2014

In 2009, the CERC brought in tariff regulations for a five year control period of 2009–2014. For hydropower, several important incentives were incorporated. The tariff regulations mandated that for the first 10 years of operation, the project would be completely protected from any hydrological risk — that is, any generation shortfall below the design energy[11] due to lack of water flow in the river (or in fact, any other reason beyond the generating company's control) — and the entire burden would be passed on to consumers. After ten years, the only concession made was that if there was any excess generation above design energy in the year following the year of shortfall, then in the third year, the project would be compensated to the extent of the shortfall offset by the excess in the earlier year.

Significantly, in years when the flow in the river is higher, and the electricity generated is higher than the design energy, the project gets to keep the charges recovered from the sale of the increased electricity generated. The 1992 and 1995 tariff notifications in the early years of the reforms offered this protection against hydrological risk only for the first seven years. The CERC Tariff Regulations of

11. 'Design Energy' means the quantum of energy which can be generated in a 90% dependable year with 95% availability of the installed capacity of the hydropower generating station.

2014 have continued this provision. The offloading of hydrological risk onto consumers is not only for private sector hydropower but is also applicable to public sector hydropower projects. This represents a clear case of socialising the risks and privatising (for the private sector developed projects) the profits. However, it is not just an issue of higher profits and offloading of risks by some companies. This represents a larger issue. Shielding hydropower generation companies from any hydrological risks offers a perverse incentive to build in higher design energy into the project resulting in higher dams, larger submergence and bigger capacities.

Further, the quality of hydrological data in India is often poor. If projects do not have to bear the hydrological risk, they would be content to use low quality data by erring on the higher design energy side. This would lead to higher design energies than what the river flows can support, with larger storages and heights for dams, leading to larger submergence, greater displacement and more environmental damage.

Indeed, such an over-design of projects is seen clearly from an analysis of existing hydropower projects carried out by Himanshu Thakkar of the South Asia Network of Dams, Rivers and People (SANDRP). Thakkar's analysis of 22 years' electricity generation data of 208 projects (30,740 MW) of the 228 operational projects in India as of 31st March 2007 shows that 90% dependable power generation in the case of 184 of them was below the design energy (Thakkar, 2008, pp. 10-11). The total capacity of these 184 projects is 25,214 MW — that is, 82% of the total analysed capacity is under-performing. What is most important is that the actual 90% dependable generation achieved by 90 of these 184 projects was less than half the design energy. This shows that projects have been heavily over-designed, and river flows over-assessed. Considering that an overwhelming proportion of the proposed hydropower capacity addition in India is in the north-eastern states where there is higher uncertainty in hydrological data, protecting projects against hydrological risks is a sure way to encourage over-designing of projects.

In what may be a recognition of this danger, the 2014 Tariff Regulations mandate as follows:

"… in case actual generation form (sic) a hydro generating station is less than the design energy for a continuous period of 4 years on account of hydrology factor, the generating station shall approach CEA with relevant hydrology data for revision of design energy of the station." (CERC, 2014, p. 92)

However, such post facto revisions, even if they have some implications for tariff restructuring, may not be of any significant consequence since the social, environmental and financial costs for the unviable capacity would have already been paid.

Another provision of the 2009 regulations, continued in the 2014 regulations, was that the CERC allowed project companies to be reimbursed for the income tax that they have to pay on their income from return on equity. Whatever tax is to be paid by the project on their return on equity is added to the amount to be recovered from the consumers of electricity, and loaded on to the tariff. In other words, the 16% rate of return on equity is a post-tax return. To ensure this, the CERC increases the rate of return on equity by the tax rate that is applicable to the company. Thus, for a company paying normal corporate tax at 33.99%, the rate of return on equity allowed and charged to the consumers is 23.481% (as against 16%).[12]

This supposedly standard industry practise of passing on taxes to consumers gets distorted here with serious implications, when one considers that hydropower companies are eligible for an income tax holiday. The CERC stated that it wanted the benefit of the income tax holiday to be available to the project developer and not passed on to the consumers. The implication of this provision is a piquant situation where the tax amount is collected by the project from the consumers of electricity by loading it on to the tariff, and not passed on to the government, but rather retained by them as they are eligible for an income tax holiday. Hydropower projects mostly have regulated tariff, and income tax is a pass through component — meaning that whatever is the tax that is to be paid by the company is passed on as it is onto the consumer — for all regulated projects. Given this, perhaps it makes more sense to make these companies pay the due taxes and claim pass through of these actual taxes in their tariff assessment.

3.7 Clean Development Mechanism

An important development during this period which incentivised hydropower projects, particularly private hydropower projects, was the Clean Development Mechanism (CDM). Even though this was a global mechanism and not a policy initiative of the Indian government, the GoI tried to ensure that as many hydropower projects took advantage of it as possible.

12. This provision is also applicable for thermal power plants, not just hydropower.

The CDM is a global market based mechanism with tradable "carbon credits" aimed at mitigating climate change by reducing carbon emissions. It was set up under the Kyoto Protocol. The following description summarises the CDM (Dharmadhikary, 2008):

"The concept is very simple. It was argued that projects leading to a decrease in Green House Gas (GHG) emissions would be cheaper to implement in developing countries than in developed countries. So, developed countries could pay the developing countries to implement projects to reduce emissions, and the cut back in emissions achieved would count towards the reduction quota of the developed countries.

"In practice, a simplified description of the way CDM is implemented is this. A project claiming to reduce emissions has to apply to the Designated National Authority (DNA, in India, the Ministry of Environment). If the DNA approves the project, it is submitted to the International CDM Executive Board (EB). … Based on their validation, the EB will Register (the technical word for approving) the project. Once registered, the project will be issued Certified Emission Reduction (CERs) or carbon credits but only when it starts operation …

"One CER is equivalent to one ton of carbon-dioxide emission saved. These CERs are bought by developed countries who can then claim that they have met their reduction target by the amount of CERs they have purchased."

Hydropower projects claimed benefits under the CDM mechanism by arguing that they save carbon emissions compared to coal-based power, which is what the country would build if the said hydropower project was not constructed.

The CDM mechanism offered hydropower projects millions of dollars' worth of income for virtually not doing anything additional. This was seen as a windfall income by developers and almost all private hydropower projects have applied for CDM credits, and most have secured the approval of the host country.[13]

The approval and registration of hydropower projects under the CDM is highly contentious. It is argued, with much logic, that most CDM approved hydropower projects violate the basic condition of the CDM, namely "additionality". "Additionality" means that the CDM money brings in projects that provide additional carbon emission savings, and not savings that would anyway have happened. To ensure that the mechanism is bringing in new reductions in emissions,

13. http://ncdmaindia.gov.in/ is the official web site of the Designated National Authority in India. Earlier it was www.cdmindia.gov.in/

a pre-requisite is that one cannot build the project claiming CDM credits unless one has the additional money that the carbon credits under CDM mechanism would bring in. Only then would the CDM money make possible new projects and new emission reductions which would otherwise not have been built. But most hydropower projects in India, including those that have applied for CDM credits, have secured their techno-economic clearances without indicating any need for CDM credits, and indeed have been justified as least-cost additions.

For example, the 192 MW Allain Duhangan project in Himachal Pradesh has been registered for CDM credits[14]. However, as SANDRP stated (SANDRP, 2008, p. 1)[15]:

"The developer applied for and got the in principle and final Techno Economic clearances [in 2002], without mention of necessity of CDM credits for making the project viable …"

"Moreover, in the Environment and Social Impact Assessment for the project done in May 2003, it is stated 'The project would be one of the cheapest sources of power generation in the Northern Region as compared to alternative of thermal and nuclear generation.' Why should a project that is supposed to be the cheapest source of power, be even considered for CDM credits that are supposed to help make relatively unviable projects viable?"

Similar is the case for virtually every project that applied and received CDM approval and registration. Thus, the CDM, which was supposed to be a support to projects which would otherwise not have been possible, was seen and used as a measure of windfall profits.

This is also clear from the fact that in the Tariff Regulations by CERC (both 2009–2014, and 2014–19 regulations), the developer is allowed to retain the entire earnings from the CDM credits in the first year. In subsequent years, this share goes down by 10% every year, till it is 50%. After that, the developer gets 50% of the CDM money, and the rest is passed on to the beneficiaries (consumers). This belies the "additionality" condition of the CDM, because if it had not been possible to construct the project without the CDM input, then the CERC would have allowed the developer to retain the entire CDM credit earning.

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14. cdm.unfccc.int/Projects/DB/DNV-CUK1169040011.34

15. See also Section 1.4, Draft Final EIA for Allain Duhangan project (Environmental Resources Management, 2003, p. 6).

3.8 Other developments in power sector reforms

Apart from the hydropower sector specific reforms described here, the sector has also been influenced by other measures and changes in the larger power sector that are not necessarily specific to hydropower. These include the introduction of the independent regulatory commissions, the passage of the Electricity Act in 2003, and the mega-project policy. Many of these measures were supposed to increase competition in the sector and encourage private developers. For the hydropower, these measures essentially continued to either provide more incentives or help reduce risks of developers, rather than increase competition or efficiencies.

The introduction of regulatory commissions which set regulated tariffs, helped find an alternative to the MoU based tariffs, but essentially maintained the cost-plus approach in setting hydropower tariffs. The Electricity Policy of 2005 promised debt financing of longer tenures for hydropower projects. The Electricity Act 2003, which with its provisions for open access, increased scope for captive power plants through use of group captives etc., was also supposed to help hydropower projects secure buyers with paying capacities. The Mega-Power Project policy put the threshold for hydropower projects at 500 MW, but also reduced this to 350 MW for the north-eastern states and Jammu and Kashmir. Projects under this policy have the benefit of custom duty free import of capital equipment and deemed export benefits.

These measures have been discussed in more detail in the Chapters 2 and 5 on thermal generation and transmission and distribution respectively.

3.9 Pace of hydropower development in recent years

As mentioned earlier, the 2008 hydropower policy proposed installing all of India's hydropower potential (about 150,000 MW) by the year 2027, with about 81,000 MW expected to be installed at the end of the 12th Plan (2017). Clearly, with the installed hydropower capacity[16] of 42,783 MW as on 31st March 2016 (CEA, 2016b), the development is nowhere near this goal. However, the pace of capacity addition for hydropower has picked up somewhat in recent years, with close to 8,000 MW being added in the 10th Plan (2002–07), 5,500 MW in the 11th Plan (2007–12) and 3,811 MW in the four years of the 12th Plan (as of 31st March 2016) (CEA, 2016c)[17]. Even the pace of private sector hydropower development has increased over the past years. This is seen from Table 3.4.

16. This includes stations with capacity higher than 25 MW, and consists of 4,785.60 MW of Pumped Storage Schemes and 37,997.82 MW of conventional hydro.

17. Even though it is a clearly declining trend, these numbers should be seen in the context of hydropower capacity additions in the earlier plans which hovered around 3000–4000 MW.

Table 3.4: Status of hydropower projects currently under construction (capacity, in MW)

	Central	State	Private	Total
12th plan, under construction	3,500	896	2,690	7,086
Under construction beyond 12th plan	2,735	1,816	1,865	6,416
Total: (12th Plan + 13th Plan)	6,235	2,712	4,555	13,502

Source: (CEA, 2016c).

Private hydropower projects constitute close to 34% of the total hydropower capacity under construction as compared to 12% of the total hydropower capacity addition in the first two and half decades after the reforms started.

The host of financial incentives, the availability of large amounts of financing from public financial sources, the opportunity for bigger profits, the promise of extra profits from the CDM, and the taking away of most risks from the private sector's shoulders seem to be responsible for this increase in pace of development in the private hydropower sector. Another reason could be the development of infrastructure and access in states like Arunachal Pradesh, Sikkim, Himachal Pradesh and Uttarakhand where much of the new capacity addition is proposed.

However, the real picture is somewhat different than what these figures indicate. While more projects are "under execution", a large number of the private projects are facing serious issues of inability to mobilise finances and slow progress. In addition, several projects are facing problems of local opposition and environmental problems slowing down the progress of the projects.

In the private sector projects, out of a total capacity of 4555 MW under construction, close to 4004 MW is facing some or the other serious problem as reported by the CEA.[18] By far the biggest problem is fund constraints of developers affecting 2200 MW or 50% of the private capacity under construction. This once again highlights the failure of the reforms to achieve one of its most important intentions — that private sector will bring in investment. In fact, the picture is that large numbers of private projects are faltering precisely on this ground. The situation is so bad that one of the largest private projects under execution, the 1200 MW Teesta III project, has had to be taken over by the Sikkim government on 6th August 2015

18. Status of Under Execution Hydro Electric Projects for 12th Plan and Beyond (CEA, 2016c).

due to financial problems faced by the developer[19]. Another large project, the 400 MW Maheshwar project in MP, is also on the verge of being taken over by the public sector for the same reason. In fact, reports indicate that several other private developers are approaching public sector players like the NHPC to either form joint ventures with them or even get their (private developers') projects taken over, as the private developers are finding it difficult to raise funds (PTI, 2015), (Jai, 2013), (Bhaskar, 2013). It may be mentioned that all these projects facing financial difficulties had earlier secured financial closure.[20] This also indicates that the private sector is not necessarily more efficient at managing projects or their finances. The case of the Maheshwar project (See Box 3.2) illustrates this point.

Box 3.2 Maheshwar hydropower project — symbol of the many problems with reforms

The 400 MW Maheshwar hydropower project on the Narmada river at Mandleshwar, M.P. is a part of the ambitious Narmada Valley Development Project. In 1993, a concession agreement for this purely hydropower project was signed with textile company S. Kumars, making it India's first private hydropower project under the 1991 reforms. A PPA was also signed with the project by the Government of Madhya Pradesh (GoMP).

In September 2015, 22 years after the project had been privatised, lenders to the project met and virtually decided to take over the project from the hands of its private promoters, marking the turning full circle by the project which has been beleaguered with myriad problems including inability to raise finances, inefficiencies in project management and construction, and a total failure on the rehabilitation front. On 28th October 2015, the National Green Tribunal (NGT) reiterated its earlier directions to the project not to lower or close its dam gates and not to cause any submergence without resettlement and rehabilitation (R&R) being completed.

19. Even though the 1200 MW Teesta III project is now a Sikkim state government enterprise, the CEA Quarterly Reports, including the 84th one, continue to list it as a private project with a footnote saying it's now a state enterprise. The 4555 MW of private capacity under construction in Table 3.4 includes Teesta III. If that is removed, the private capacity under construction becomes 3355 MW and only 24% of the capacity under construction.

20. CEA Hydro Project Monitoring, Quarterly Review No. 82, (CEA, 2015), Chapter 10: Status of financial closure of under execution private sector H. E. projects for likely benefits during 12th Plan and beyond.

The Maheshwar project represents much of what was wrong with privatisation in the hydropower sector and vindicates many of the critiques of the reforms process.

The project initially received equity and export credit financing from several international agencies as well as concessional financing support from Indian public sources. Table 3.5, with figures from the lenders' meeting, reveals how the project has been financed till now.

Table 3.5: Details of Maheshwar project financing

Source	Amount (₹ Crore)
Equity – from Investors and Promoters	499
Power Finance Corporation	700
HUDCO	259
REC	250
State Bank of India	200
Edelweiss ARC	180
LIC of India	106
IDBI Bank, IFCI Bank, Dena Bank	112.5
Total	2306.5

This shows that the investors, including the promoters, have brought in ₹ 499 crores as equity. The lenders have brought in another ₹ 1807 crores, or close to 78% of the money spent so far. The major lenders are mostly public or government owned financial entities. This total expenditure of ₹ 2306 crores till date should be seen against the project cost as estimated by the CEA ((CEA, 2016c), Chapter 6) at ₹ 6793 crores.

Early in the project execution, serious issues of R&R and human rights violations become clear, as well as a reluctance of the GoMP and project developer to address them meaningfully. Repression was the main response of the government. Seeing this, several international funders withdrew their equity as well as other financing.

The oustees got organised under the banner of the Narmada Bachao Andolan (NBA) in the late 1990s. Apart from questioning the project on R&R, the NBA also started investigating the environmental impacts and the economics of the project. It found that the PPA was skewed heavily in favour of the private project developer and that the power from the project would end up being prohibitively costly. However, both project proponents and the GoMP brushed aside these issues which subsequent developments have vindicated.

The costs of the project kept going up. Even as the project claimed to have tied up all finances, it could not manage to fund crucial activities and the pace of the project remained slow. The project remains incomplete till date. The transactions between the government and the private developer were opaque and there were allegations of crony capitalism and of undue favours from the government in providing financial support. The skewed power purchase agreement meant that in December 2011, the tariff from the project had already reached ₹ 8.53 per kWh (Infraline Energy, 2011).

With the project virtually at a standstill, a committee was formed on 16th October 2014 under the chairmanship of Additional Chief Secretary (Finance), Government of M.P. to find ways to salvage the project. In its report presented on 2nd May 2015, the committee proposed three possible scenarios. In the first scenario, the project promoter was to bring in an additional ₹ 600 crores as equity and ₹ 1100 crores as debt and complete the project. The actual amount needed would probably be significantly higher, since the gap between the CEA estimated project cost and money already spent is ₹ 4487 crores. The promoter was to be given three months to do this. As he failed in meeting this target, the second option was automatically triggered, leading to the lenders taking over the project in September 2015. The lenders now have the difficult job of trying to find a public sector entity to bring in ₹ 4487 crores and take over the project. This difficulty is compounded by the fact that the state government has declared that it will not pay more than ₹ 5.32 per unit for the power from the project, which itself is quite a high price.

The project, whose future remains uncertain, had ended up symbolising many of the problems with the reforms in the hydropower sector.

At the same time, several other projects, private and public, are facing challenges for not being able to address social or environmental impacts, indicating continuing failure of reforms on this front as well.

For example, work on the biggest projects currently under execution, the 2,000 MW Subansiri project in Arunachal Pradesh/Assam, has been stopped since 16th December 2011 due to agitations by mass organisation groups in Assam, who have been raising the issue of the downstream impacts of this and other projects in Arunachal Pradesh. Several other projects are also facing local opposition. This aspect is discussed in detail later.

Thus, it may be incorrect to conclude that one of the key elements of the reforms — privatisation and bringing in private investment to boost the progress of hydropower — is at last picking up.

3.10 Assessing the reform measures

In the context of this broad sequence of events and developments, let us now try and assess whether the hydropower reforms have met their stated objectives as well as broader developmental goals for the power sector and the country.

3.10.1 Augmenting investment through private sources

The main objective for power sector reforms in general and hydropower in particular, an objective that is repeated at every juncture, is the need to get more investment in the hydropower sector from private investors, as government sources are not enough compared to the levels of resources needed.

Has this happened?

In 1991, the total hydropower installed capacity in the country was 18,610 MW. As on March 2016, this was 42,783 MW (CEA, 2016b) (Projects greater than 25 MW). Thus, about 24,000 MW of hydropower capacity has been added since 1991, out of which the private sector has added only 3004 MW, that is, barely 12.5%.

If we assume that all the projects under construction will be completed as per schedule, an unlikely prospect given the financial and other problems they are facing, even then, the contribution of private hydropower would be 7,559 MW, out of a total addition of 37,502 MW, that is, around 20%. This would be at the end of about 30 years of reforms. The figures for investments that the private developers are expected to deploy are similar. Table 3.6 gives the expected investment levels for hydropower projects in the 12th Plan.

Table 3.6: Fund requirement for 12th plan hydropower projects (in ₹ Crore)

	Centre	State	Private	Total	Private as % of total
12th plan hydropower	35,183	8,024	6,952	50,159	14%
Advance action for 13th plan hydropower	28,132	612	11,216	39,960	28%

Source: (Planning Commission, 2012, p. 333).

Thus, figures for both, capacity addition as well as investment likely to be brought in, show that the role of the private sector in hydropower is limited to around 15-20%, even 25 years into the reforms.

Moreover, it's also useful to see whether this investment brought in by the private sector is really "additional" investment as was envisaged by the reforms process. One of the conditions when the sector was opened up for private participation was that at least 60% of the total project outlay was to come from sources other than Indian public financial institutions. The rationale for this was that the very purpose of privatisation was to bring in additional resources. However, private projects were not able to raise such resources, and on 13th October 1998, this condition was withdrawn, allowing projects to source as much financing as they wanted and could from Indian public financial sources. (GoI, 1998a)[21] Thus, the very objective behind the reforms was diluted in just a few years after their initiation.

While the contribution to actual additional capacity creation and bringing in additional resources seems to be very limited, it would also be important to see whether reforms in the hydropower sector met other goals. Some of the other important objectives in the reforms process were bringing in competition and operation of market principles in the sector, (to facilitate) technical and economic efficiency, provision of affordable and reliable power supply, electricity access to all, peaking power provision, development of remote areas, managing environmental impacts, and ensuring proper resettlement and rehabilitation of affected people.

It would appear that most of these objectives were not met.

21. Government of India Resolution No. A-67/96-IPC. I (Vol. II), dated 13th October 1998, published in the Gazette of India, Extraordinary, No. 227, dated 15th October 1998, Ministry of Power.

3.10.2 Competition and market operation

The main logic behind the reforms process was that bringing in competition, the private sector and operation of free market forces in the sector would result in technical, financial and economic efficiencies. As far as hydropower was concerned, while privatisation was the first aspect to be introduced, it is ironic that the private players kept on lobbying for, and succeeded in preventing or cutting back the introduction and implementation of the other aspects, namely, competition and market operation.

Attempts to introduce competition in the sector have been weak and unsuccessful. The initial selection of projects and developers and allocation of sites to private players was done entirely through one-on-one negotiations between states and the developers. Moreover, the processes through which the MoUs were signed, and the MoUs and the PPAs themselves, were marked by a total lack of transparency. The determination of the tariffs was also to be carried out through a formula based on the cost-plus principle, and the most important parameter in this formula, the cost, was not only not determined by the market, but was susceptible to padding and manipulation, as there were hardly any checks, at least in the initial years. Thus, there was no competition or market orientation in any of the parts of the process.

After the cost-plus regime resulted in huge increases in capital costs, a new provision was introduced in January 1995 that no more projects were to be contracted through the MoU route after the cut-off date of 18th February 1995. Later, tariff determination for private hydropower projects was changed from a regulated, cost-plus basis to competitive bidding, though it appears that no hydropower project actually opted for such bidding. However, the hydropower policy of 2008 finally reversed this and allowed private sector hydropower projects to get back to a regulated, cost-plus basis for tariff determination, thus practically admitting to a failure to introduce competitive bidding.

The 2008 hydropower policy did mandate international competitive bidding for the equipment supply and construction of the project for it to be exempt from tariff-based competitive bidding (or for it to get tariff determined through a cost-plus approach). The tariff regulations by the CERC also included a prudence check by the commission of the capital costs of projects, and also provided for the commission to issue guidelines for vetting of capital costs of hydropower projects by independent agencies. However, the efficacy of these measures in keeping a check on the capital costs is not clear, and such arrangements are clearly against the

spirit of competition. At best, they constitute substituting competitively discovered costs with administrative scrutiny of capital costs. The very intention of introducing competition is to eliminate such administrative scrutiny.

In case of hydroelectric projects, one of the most important inputs, namely land, was acquired not through any market operations at market prices, but through compulsory acquisition using the colonial legislation, Land Acquisition Act 1894, at very low prices, in which the owners of land had no say. Again, this is the very anti-thesis of competition and market principles which the reforms wanted to promote.

There was no risk of not finding buyers for the electricity, as the power off-take and payments were guaranteed with state/sovereign counter guarantees, or escrow arrangements. Where these were absent, the private sector was hesitant to enter.

It can be argued that at least this last concession, guaranteeing the purchase and payments, was necessary because the sole buyers at that time were the SEBs and their paying capacity was not credible. This raised the question about the extent of the 'market' for power (as against the 'need' for power) in the country, particularly in context of the excessively high tariffs that were seen in the earliest IPPs like Enron and Maheshwar, and whether it was then at all advisable to bring in private developers without ensuring genuine competition and price discovery, by a functioning market that would ensure market prices capturing full benefits of competition.

In addition, as discussed earlier, hydropower entrepreneurs were largely protected from the risks that come with such projects while being promised attractive returns. It may be mentioned here that the key aspect that entitles private entities to (high) profits — the very word 'entrepreneur' signifies it — is that they take risks. This warrants higher profits, but also carries the risk of making losses. However, the way privatisation was structured, the private players were protected from virtually every risk (which was taken on by the government or the public), but the quest for profits remained. There was little risk of estimating the correct tariff, of finding buyers, of payments, and no hydrological risk as well. At the same time, there were few systemic incentives for ensuring lower costs and efficient operation, or for ensuring better social and environmental outcomes.

Thus, it is clear that even as we approach the completion of 25 years of reforms, the hydropower sector is far from achieving any real competition or operating on

market-based principles. On the contrary, the enhanced incentives (ultimately paid for by the taxpayers) and insulation from all forms of risks, which are increasingly shouldered by the state or the public, has bolstered private participation in the sector — though even then it is much less than what was targeted, and its outcomes still uncertain.

3.10.3 Social and environmental impacts

It's an oft-repeated statement that hydropower projects, particularly the large ones, have many serious social and environmental impacts. Indeed, these have been identified among the difficulties of implementing hydropower projects. In spite of this, the reforms process did little to address and improve the process of dealing with the social and environmental impacts of hydropower projects.

One of the problems is that rather than appreciating the impacts themselves, official and industry positions have often identified the criticism of the environmental impacts of hydropower projects from environmental activists as the main problem. This is shooting the messenger, rather than looking at the message. Naturally, the measures taken by the government have been tailored by this approach.

We fill first look at the environmental governance processes, while keeping in mind that in a country like India, social and environmental impacts cannot be seen separately.

In the early and mid-1990s, the environmental governance regime was also undergoing a change independent of the power sector reforms. In this period, there were some important measures taken to strengthen the regime. This included the 1994 EIA (Environmental Impact Assessment) Notification of the Ministry of Environment and Forests, which unambiguously established the Environmental Clearance as a statutory requirement for projects including large hydropower projects.[22] It also brought in the public hearing as a pre-requisite to the environmental clearance.

The response from the power sector reforms, particularly for the hydropower projects, was that of trying to protect the projects from the perceived onerous requirements of the changing environmental governance regime. While there was an attempt to insulate both public sector and private sector projects, there were several additional concessions made for the private projects.

22. Prior to this, the status and necessity of the environmental clearance was ambiguous, with it being described as an administrative clearance in some cases.

As mentioned earlier, the Sambamurti Committee in 1996 had identified the criticism by environmental activists as a major reason for the slow progress of hydropower projects. It suggested hydropower schemes with the least impacts should be taken up first, and that others should be subjected to a more detailed study. However, in recommending that these environmental studies be undertaken by the CEA/CWC, it underestimated the seriousness of these impacts, as it did not think that such assessments needed more specialised bodies to carry them out. Further, it also ignored a conflict of interest as the CWC/CEA are essentially bodies that are pushing dams and hydropower projects, and this role of theirs would hamper a full appreciation of the environmental impacts of such projects. Further, the committee also recommended that for private projects, some of the environmental measures should be undertaken by the government.

Incorporating the recommendations of the Sambamurti Committee, the 1998 Hydropower Policy stated that "there is… a need that project authorities are insulated from the problems arising out of land acquisition and R&R. It will be the responsibility of the State Govt. (sic) to acquire the land … Similarly, all the issues of resettlement and rehabilitation associated with the projects have to be addressed by the State Govt." (GoI, 1998b, p. 18).

Even as the environmental governance regime was being strengthened, the measures to put in place a better environmental governance regime did not go far enough and to their logical ends. For example, while a public hearing was mandated, it came too late in the decision-making process, and most of the representations made at the hearing were largely ignored. The result was that environmental impacts of hydropower projects were hardly addressed in any meaningful manner.

The India Country Study of the World Commission on Dams (Rangachari, Sengupta, Iyer, & Singh, 2000, pp. 211-212) noted in 2000 that dams (including hydropower projects) continued to adversely impact the environment.[23] The reasons outlined for this in the report included the use of sketchy guidelines prepared in the 1980s, even minimal assessments required by such guidelines not being done, EIAs being done when the project was at an advanced stage rather than during early project preparation, EIAs prepared by consultants hired for, paid by and supervised by project promoters, disregard of conditions of clearance once the clearance is obtained, and little by way of monitoring compliance after clearance.

23. The study referred to the 1800 or so dams whose construction started after 1978 when the government first introduced the requirements for environmental impact assessments and clearances.

The reforms process did little to address any of these aspects, resulting in continuing serious social and environmental impacts.

It is little wonder then, that the 1990s saw a spate of intense struggles and protests against large dams, including hydropower projects, which persist even today.

Unfortunately, most factors outlined in the India Country Study continue to be the same even today, and dams and hydropower projects continue to have serious impacts on the environment. Implementation and monitoring remain extremely weak, with lip service being paid to environmental rules and regulations.

One interesting example of how environmental assessment is not being implemented relates to the Electricity Act of 2003. This Act, which consolidated the power sector reforms and also laid out significant new provisions, also has a provision that has implications for comprehensive assessments of hydropower projects, including the environmental aspects. The Electricity Act mandates that hydropower projects (above a certain size) need to have a concurrence from the CEA. Section 8(2)(a) of the Act lays down what factors the CEA should consider while giving this concurrence. The section is quoted below.

"(2) The Authority shall, before concurring in any scheme submitted to it under sub-section (1) have particular regard to, whether or not in its opinion, (a) the proposed river-works will prejudice the prospects for the best ultimate development of the river or its tributaries for power generation, consistent with the requirements of drinking water, irrigation, navigation, flood-control, or other public purposes, and for this purpose the Authority shall satisfy itself, after consultation with the State Government, the Central Government, or such other agencies as it may deem appropriate, that an adequate study has been made of the optimum location of dams and other river-works;"

Thus, the CEA has to ensure that a hydropower project has to be an integral part of this best ultimate development of the river for power generation, and therefore, has to be examined within the framework of the development of the entire river basin.

Further, this best ultimate development has to weave in the requirements of drinking water, irrigation, navigation, flood control and "other public purposes", which we would argue have to include preservation of ecology, biodiversity and protection of culture and livelihoods of the communities in the basin. Unfortunately, this section and its requirements have never been followed in any meaningful manner.[24]

24. See (Dharmadhikary, 2009) for a more detailed analysis.

Moreover, instead of strengthening the environmental regime, the last decade has seen its weakening. For example, the revised EIA Notification of 2006 allows the concerned authority to do away with the public hearing in case it feels that the local situation will not allow free expression of views. Environmental activists and others see this as a way to bypass the opposition to such projects that is often expressed in public hearings. Most recently, the TSR Subramanian Committee set up by the MoEFCC in 2014 to suggest a revamp of environmental laws has presented recommendations that threaten to greatly weaken environmental regulation. While the recommendations have been criticised by civil society, even the Parliamentary Standing Committee on Science and Technology, Environment and Forests has in its report (263rd report tabled in the Rajya Sabha on 21st July 2015) strongly criticised the TSR Subramanian committee report and has asked for it to be rejected.

Evidence for casual and lax implementation of the environmental regime can also be found in the way hydropower projects are being cleared.

An analysis carried out by the South Asia Network on Dams, Rivers and People (SANDRP) in 2013 of environmental clearances granted to hydropower and river valley projects by the MoEFCC (SANDRP, 2013, p. 4) found that:

"The Union Ministry of Environment and Forests' (MoEF) Expert Appraisal Committee (EAC) on River Valley and Hydroelectric Projects (RVP) has considered a total of 262 hydropower and irrigation projects in close to six years since April 2007 when the new committee was set up to its latest, 63rd meeting in December 2012. It has not rejected any project in this period. Even in case of the two projects that it declined to recommend clearance for the Terms of Reference (TOR) of their Environment Impact Assessment (EIA), it has basically asked the developers to come back with reformulated proposals. It seems the committee is actually an Expert Approval Committee, since it seems to have expertise in approving rather than appraising the projects objectively."

This implies either an exemplary and exceptionally high standard of project preparation and appraisal, or a dismal standard of regulation and clearance procedures. The SANDRP report also documents in detail several shortcomings in the process, including neglect of cumulative impact assessments in a situation where virtually every river valley in the Himalayas is seeing the proposed construction of a cascade of hydropower projects.

One of the most serious lacunae in the environmental governance regime is that there is no meaningful consideration of the impacts of climate change. This is particularly serious as most of the new proposed hydropower projects are likely to come up in the Himalayan region, which is widely recognised as one of the regions most vulnerable to climate change globally. Climate change is likely to aggravate the already serious issues of the region like landslides, erosion, seismicity, floods and Glacial Lake Outburst Floods (GLOFs). The environmental clearance and monitoring regimes have ignored both, the risks from climate change impacts like extreme rainfall events to the cascades of dams being built in the Himalayas, and the danger that these projects will aggravate the impacts of climate change in the Himalayan region.

In June 2013, Uttarakhand was stuck by unprecedented floods that caused huge loss of life and property. A question was raised by many observers whether hydroelectric power projects existing and under construction in the river basins of Alaknanda, Bhagirathi and their tributaries have contributed to environmental degradation and, if so, to what extent and also whether they have contributed to the tragedy that occurred at Uttarakhand in the month of June, 2013. However, the government refused to look at this question, till the Supreme Court intervened in the matter and forced the MoEFCC to set up a committee with the above question as one of its Terms of Reference. The committee's report[25] found (except a dissenting note by the CEA and the CWC) that the hydropower projects had indeed aggravated the impacts of the floods. It also noted the damage to hydropower projects due to the floods. Yet, there is no move to meaningfully examine the implications of climate change for hydropower, particularly in the Himalayas.

Thus, instead of making the scope of the environmental assessments more meaningful and the implementation better – which should have been an integral part of the "reforms" – we are seeing a bigger push to dilute the environmental protection regime. This is likely to cause even more conflict situations in hydro projects around environmental impacts. It is difficult to understand how the reforms have failed to address what the government itself calls one of the most important factors for not being able to realise the "potential" of hydro. The consistent approach seems to be that environment is an impediment, and the only way to address this is to keep diluting the norms and regulations. This stems from the failure to realise

25. The report of the committee, though a public document is not available online. The authors had access to the report. (Dharmadhikary, 2014) is a detailed article on the report.

that hydropower development has to meet multiple goals and be consistent with other goals, including conservation and enrichment of the environment, if it is to be truly socially sustainable. The reforms have ignored this aspect of "sustainability" and reduced the goals to the narrow focus on creating more installed (hydropower) capacity regardless of other impacts.

More serious is the case of land acquisition and resettlement and rehabilitation. Land for hydropower projects is being acquired compulsorily under the Land Acquisition Act 1894 (till very recently when this Act was superseded). The very fact that such a means of acquiring land continues to be used along with reforms that argue for competition, privatisation and marker operation indicates that these principles are used as per convenience rather than as a basis of real reforms.

Under the 1894 Act, there was no legal right to resettlement and rehabilitation for anyone from whom land was being acquired. The only entitlement was that of cash compensation. Numerous studies have documented the disastrous impact of cash payments particularly to tribal and other communities who are not familiar with cash economies. Yet, there were no attempts to address this aspect in any meaningful manner. The hydropower policies in 1998 and 2008 made some attempts to address this aspect, but they were woefully inadequate. Some details of these have already been discussed earlier in this chapter. It is only in 2013, with the passage of the Right to Fair Compensation and Transparency in Land Acquisition, Rehabilitation and Resettlement Act, 2013 that some amount of justice and fairness has been introduced in the land acquisition process, in spite of critical shortcomings of the Act. However, there were also attempts to dilute the provisions of this Act, and so there remains some uncertainty about how long these provisions will remain applicable. Also, it's not clear whether and to what extent the provisions of this Act apply to some of the most serious impacts of hydropower projects — for example, on communities downstream of dams and diversions, or communities affected by the large-scale tunnelling that is taking place in the Himalayas for hydropower projects. Finally, it should also be recognised that even the passage of this Act does not address the inconsistency of arguing for a market based regime for power but allowing compulsory acquisition of land needed for power projects.

The lack of seriously addressing social and environmental impacts has been a big lacuna in the reforms process, and though various government committees acknowledge its importance (GoI, 1997) (GoI, 2008), no concrete actions have been taken in this regard. This can lead to an inference that addressing social and

environmental concerns in a meaningful way was seen as increasing the cost of hydropower projects, delaying them or making them less attractive to investors. In the process, the ordinary people, particularly those living in the river valleys, have borne great adverse impacts and river valleys have witnessed severe degradation of the environment.

The neglect of these aspects is also one more pointer that the reforms were narrowly focused only on financial issues, with the sole objective of obtaining private and global investments. Anything that seemed likely to block such investments was eliminated, sidelined or disregarded — ironically, even measures like making the sector competitive and market oriented, measures that were supposed to be inseparable parts of the package of privatisation and globalisation that was to introduce efficiency, performance and plenty in the power sector.

3.10.4 Providing Peaking Power

An important argument in favour of hydropower is its ability to meet peak demands for electricity. Hydropower stations can start and stop quickly and ramp up or scale down their generation very fast. This gives them the ability to meet daily peak loads, and follow the demand profile. In fact, this ability of hydropower stations is often cited as a justification to balance their high social and environmental costs.

This is the reason that the reforms from time to time have advocated a special premium in tariff to be paid to hydropower generators for supplying power to meet peak loads. This was supposed to be an additional incentive for hydropower developers, especially private developers. But this incentive of premium tariffs for hydropower supplying in peak times does not seem to have been realised at any point of time in the reforms.

Further, the equation between a hydropower station and meeting peak loads is not straightforward or inevitable. While hydropower generators generically have the ability to meet peak loads, not every hydropower plant can meet peak demands. Further, not all projects will be able to meet peak demand at all times, and also the extent to which they can meet the demand will change. There are several reasons for this. Many hydropower plants are multipurpose projects, and priority in such projects may be accorded to water releases for other uses, for example, irrigation. In such a case, the timing and extent of the releases would be governed by these priorities and it could imply that the plant would not be able to generate at peak demand time. Sometimes, particularly if a project has to release water for feeding

other downstream projects, it may operate as a base load plant — that is, generate throughout the day.

Further, problems of power procurement and planning can mean inefficient operations and hydropower not being dispatched during peak demand.

Last but not the least, the extent to which a hydropower plant can meet peak demand will also depend on its storage and water availability. In case of drought years, the ability to meet peak (and even base) loads will be compromised.

Of special interest here are the so called run-of-the-river (RoR) hydropower plants. In theory, these plants operate on the flow of the river. Thus, they have minimum social and environmental impacts. A large number of existing, proposed and under-construction plants in the Himalayan region are designated and built as RoR projects. The argument made is that they are thus relatively benign. However, these are not really RoR projects in the true sense of the word. Most are small-reservoir-and-tunnel projects. In these projects, a dam impounds water in a (relatively) small reservoir, to store water sufficient for daily generation. The water is diverted into a tunnel, and then discharged back into the river, but many kilometres down, where the river has now reached a lower level as a river flows down slope. This allows for the head (height) which is necessary to generate electricity. In the process, large sections of the river can become dry as the water is diverted into tunnels, and the projects end up having severe adverse impacts.

The extent to which these plants can generate electricity to supply at peak times is limited, as it has limited storage. The situation is further complicated as there are a number of such projects being built on a single river or in a single river basin, as a series of dams or cascades. In such cascades, ensuring electricity production in the quantum necessary and at the time needed involves added complexities, affecting the extent to which the peak demand can be met.

Given these factors, it cannot be assumed that every hydropower project will be able to, and end up meeting peak demands, and that a project will meet peak demands to the extent of its installed capacity.

While suggesting that hydropower projects should be incentivised by paying them a higher tariff for meeting peak loads, the reforms should have developed a framework that would establish the extent to which each project would actually be able to, and would end up meeting peak loads. In the absence of such a framework, it is neither possible to determine the extent to which this benefit of hydropower

has been realised, nor ensure that incentives are given to the right projects and commensurate with benefits.

Indeed, even the actual performance of existing and operational hydropower projects in this regard has not been analysed or documented. This, along with the possible contribution of the proposed projects, needs to be realistically assessed. Such a study would also enable providing appropriate premium for peaking power. Such a study is also particularly important because peaking operations of hydropower projects have severe implications for downstream areas, with sharp rises and falls in water levels.

3.11 Reforms in the coming years

Even as the evidence shows yawning gaps between the promise and performance of the reforms in the hydropower sector, and considering the fact that the reforms till date have not addressed several critical areas like competition, social impacts and environmental sustainability, steps being planned for the future indicates a policy of "more of the same".

On the one hand, both hydropower developers, especially the private developers, and hydropower rich states are calling for the package of more incentives and less risks.

A recent publication brought out by ASSOCHAM and Price Waterhouse Coopers, and released at a conference in the presence of many officials and the then Chief Minister of Arunachal Pradesh, the late Shri Kalikho Pul, presents several recommendations to the government for revitalising the growth of hydropower in the country. Some of these include a provision of infrastructure like dedicated transmission corridor for hydropower by the government, preparing projects with completion of all activities like land acquisition and statutory clearances and then handing them over to developers, fiscal incentives like tax holidays, exemption on VAT and customs duties, interest rebates on long term loans, viability gap funding, hydropower purchase obligations, premium payment for ancillary service like maintaining grid reliability, and so on. (Assocham, 2016)

The report also asks for social and environmental impact assessments "to be given due importance instead of treating them as mere legal formalities", and also "involvement of project affected persons (PAPs) and joint consultation processes between the developer, government and PAPs …" (Assocham, 2016, p. 16). Yet, the absence at the conference, or in the preparation of the report, of organisations of hydropower affected people and groups that are spearheading issues of social and

environmental impacts of hydropower projects indicates the lack of seriousness of these sections of the recommendations.

As Chief Minister of a state with huge hydropower potential, Pul also made similar demands (Dutta, 2016). He asked for the government to increase the loan pay-back period for hydropower project from 10 years to 25–30 years, and the provision of a single window clearance system.

It appears that the government is also planning to accept such demands. The central government is likely to announce a comprehensive policy for hydropower soon. (Earlier, it was slated for announcement in September 2016). This policy will have provisions like viability gap funding, compulsory hydropower purchase obligations for utilities and extending the ambit of renewable hydropower to projects greater than 25 MW. This seems to indicate that the government is planning to continue with the same approach to reforms as last few decades.

The neglect of social and environmental aspects is also likely to continue. Recently, the Union Power Ministry has invited proposals from several agencies to prepare basin-wise reviews of hydropower potential. Apart from aspects like hydrology, topography and other parameters, the studies would also look at social and environmental impacts, resettlement and rehabilitation, other water uses like irrigation, water supply and environmental flows etc. (Jog, 2016). While this is a welcome step, the names of agencies invited are a clear give-away that only technical parameters are likely to be considered important, and others will be paid lip service. The agencies invited include the Tehri Hydro Development Corporation (THDC) whose record of resettlement at the Tehri project is abysmal, and Water and Power Consultancy Services (WAPCOS) which has carried out several river basin studies whose quality leaves much to be desired.

All in all, it appears that there is little critical thinking about the reforms in the hydropower sector, and that they are set to continue along the same path of neglect of issues like competition, social and environmental impacts, and narrow focus on financial issues; providing more incentives and reducing risks of developers; and privatisation.

3.12 Conclusion and lessons

In conclusion, we can see that the reforms in the generation sector were initiated with the main objective of bringing in additional, private investment in the sector. On this count, the reforms have clearly failed in the hydropower sector, with the

private sector bringing in limited installed capacity and even smaller additional investment. Even this dismal performance has been achieved at the cost of a host of concessions and incentives that have been provided, whose costs have been ultimately borne by consumers, and with many of the risks being taken by the state or post facto passed through to the public.

The earlier sections also highlight that such projects have huge social and environmental impacts and hence the decision to build such capacity should be based on carefully evaluated considerations. Given this background and the current state of affairs, the following key lessons emerge:

1. Hydropower generation is not very amenable to private sector participation: As this review shows, both the Indian experience of the last 25 years, as well as the international experience shows that the hydropower sector is not fully amenable to privatisation. Moreover, privatisation by itself has not resulted in new and higher investment inflows, more efficient construction and operation of plants, or lower costs to the extent expected. This warrants a thorough review of the desirability of encouraging and incentivising privatisation in the hydropower sector.

2. Performance of public sector hydropower has also been found wanting: The performance of the public sector in hydropower is also inadequate on many fronts. The slow pace of addition of hydropower capacity, the consistent failure to meet targets of capacity addition, and time and cost overruns are indications of the inefficiencies of the hydropower power sector, including the public sector. At the same time, the public sector has also failed miserably to address social and environmental impacts of hydropower development.

3. Reforms are narrowly focussed and not designed as per claimed objectives: While the stated aim of the reforms were to introduce privatisation, competition and market operations to tap economic and other efficiencies, in reality, the reforms introduced only privatisation, and other aspects like competition and market operations were introduced only selectively and where convenient. Allowing land to be compulsorily acquired is one such example. Further, there was no learning from earlier failures or shortcomings and the reforms have followed essentially a "more of the same" approach. Reforms continued to focus only on the financial aspects and ignored other equally important aspects like environmental and social impacts. Even in financial aspects, they were narrowly focussed on incentivising private players rather than ensuring a competitive environment that would induce efficiency, as was the stated aim.

4. Pushing hydropower without addressing the social and environmental impacts is disastrous: Adverse social and environmental impacts of hydropower continue to be borne by river basin communities. There is a need to enshrine a comprehensive, fair and effective regime to address social and environmental impacts of hydropower projects. The recommendations of the World Commission on Dams can provide a useful framework. Projects with very high social and environmental impacts, projects that do not have broad local acceptance, and projects leading to a sub-optimal use of transmission, land and water should be put on hold till all other options are exhausted.

5. Actual contribution of hydropower in peaking is not established: One of the key arguments for the need to build hydropower projects in the face of the many costs and problems is that these projects provide peaking power. However, the actual performance of operational hydropower projects in this regard has not been analysed or documented. This, along with the possible contribution of the proposed projects needs to be realistically assessed. Such a study would also enable providing an appropriate premium for peaking power. Such a study is also particularly important because peaking operations of hydropower projects have severe implications for downstream areas with sharp rises and falls in water levels.

6. Project siting: Much of the proposed hydropower capacity is coming up in the Himalayan states, with a large number of projects in a cascade in each river basin. Such a concentration is not desirable from the social, environmental, safety and other aspects like protection and preservation of rivers. Thus, location and extent of hydel generation capacity in each basin, and environmental clearances for them should be constrained by cumulative carrying capacity, cumulative impact assessments, and environmental flow requirements.

4

Renewable Energy (RE): The imperative for the future

"Alice: Would you tell me, please, which way I ought to go from here?

The Cheshire Cat: That depends a good deal on where you want to get to.

Alice: I don't much care where.

The Cheshire Cat: Then it doesn't much matter which way you go."

- Lewis Carroll, Alice in Wonderland

4.1 Introduction and overview

India needs a comprehensive approach towards its energy future given the multiple imperatives of universal and affordable energy access, energy security, limited fossil fuels reserves and their socio-environmental impacts, local as well as global. The United Nation's Sustainable Development Goals (SDGs) clearly lay down the global vision for energy — *universal access to affordable, reliable and sustainable energy* (United Nations, 2015). Renewable Energy (RE)[1] thus, is a critical foundational element of that vision.

The reduction in the costs of renewable energy, coupled with its vast resource potential, has finally transformed it in the last few years into a serious mainstream supply option. It is no longer merely seen as an answer to the environmental problems emerging from energy production, especially climate change. Apart from its environmental benefits, RE's contribution towards increasing energy security

1. Renewable Energy (RE) resources represent energy flows, which are naturally replenished at a rate that equals or exceeds its rate of use and includes low-carbon technologies such as solar, wind, hydropower, tidal, wave and ocean thermal energy, as well as renewable fuels such as biomass. Unlike most countries, India only counts Small Hydro Power (SHP) < 25 MW as part of Renewable Energy, while conventional large hydropower (> 25 MW) is not part of the official definition of RE in India. There is a proposal from the GoI to count large hydropower as part of RE (PTI, 2016). This is contentious given the high social and environmental impacts of large hydropower. For more details on large hydropower, please see Chapter 3, Reforms in hydropower: Missing the woods for the trees.

and reducing the country's Current Account Deficit[2] add to its value as a supply resource. Absence of fuels (especially with respect to wind and solar) and minimal marginal costs make them amenable to long-term Power Purchase Agreements (PPA) based on fixed levelised prices, thus reducing electricity price volatility. All these factors have translated into a strong policy and regulatory push for RE, leading to an installed capacity of 46 GW (~15% of total capacity) as of 31st October 2016, with a contribution of 5.6% to electricity generation[3] in 2015–16 (MNRE, 2016; CEA, 2016; MNRE, 2016a). This strong capacity growth (Compounded Annual Growth Rate (CAGR) of ~ 20% from 2002-2016, as is seen in Figure 4.1) has been primarily driven by the private sector until now.

India's Intended Nationally Determined Contributions (INDC) submission to the United Nations Framework Convention on Climate Change (UNFCCC), among other things, aims to reduce the emissions intensity of its GDP by 33 to 35% by 2030 from the 2005 level[4], and to achieve about 40% cumulative electric power installed capacity from non-fossil fuel based energy resources by 2030 (GoI, 2015). With the announcement of a target of 175 GW[5] RE by 2022 (100 GW of solar and 60 GW of wind) (PTI, 2015), renewables will provide the mainstay of such contribution, overtaking conventional capacity addition in the coming years. Various characteristics of renewables, such as low gestation period, variable generation, long term fixed price contracts, low marginal costs, etc. differentiate it from conventional generation adding to the need to study past experiences in order to prepare for the future.

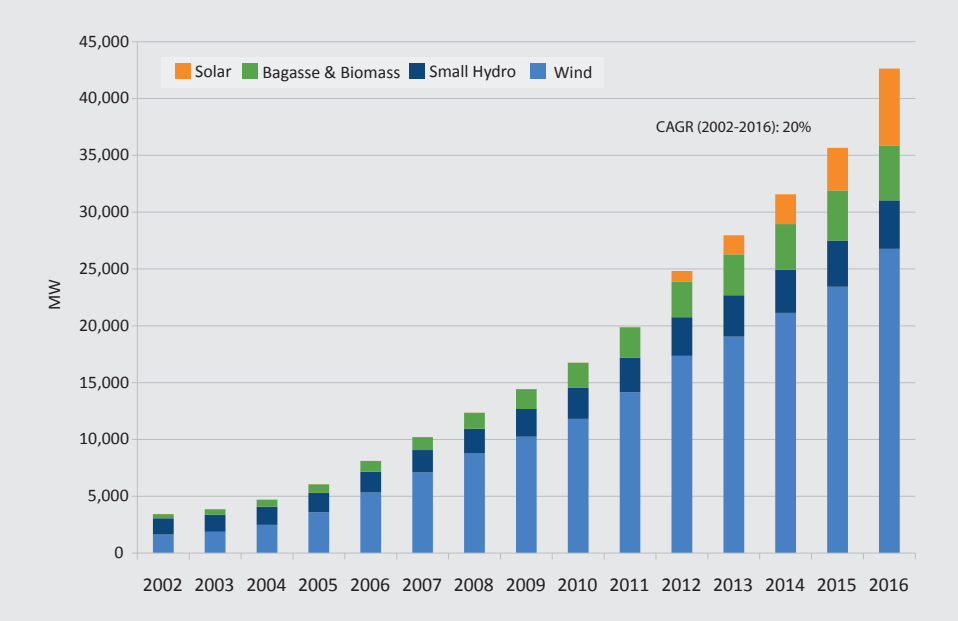
2. RE helps avoid imports of fossil fuels (especially coal). This is especially important since India is one of the world's largest coal importers. The share of energy in India's total current account outflows was over 30% in 2013–14, while net energy imports were just below 8% of Gross National Product in 2013–14 (CCO, 2015; MoF, 2015; MoPNG, 2015).

3. For comparison with other countries, RE capacity (including large hydropower) stands at ~29% (October, 2016) and electricity contribution at ~16.4% (2015–16).

4. In 2009, India voluntarily pledged to reduce its emissions intensity by 20–25% by 2020 from the 2005 level.

5. The flagship event of the MNRE (RE-Invest, February 2015) garnered a massive support from private developers to develop a potential of 217 GW (Solar: 166 GW, Wind: 45 GW) in five years. 2015.re-invest.in/greenenergycommitment.aspx RE is expected to be 17% of electricity generation by 2022 (MNRE, 2016c).

Figure 4.1: Growth of RE generation capacity (MW) from 2002–2016



Source: Ministry of New and Renewable Energy.

This chapter looks at experiences and learnings specifically from the wind and solar sectors since they will be the largest contributors to the renewable electricity mix. It attempts to chart the important developments in these two sub-sectors from a policy-regulatory, and competition-markets lens and arrive at learnings for improving ongoing and future policy-regulatory processes.

4.2 A brief history of policy and regulatory reforms in the RE sector

The sector has seen its fair share of reforms over the years, of which the important ones are captured below.

4.2.1 Incentives

In 1992, the electricity generation sector (including renewables) was opened up to private companies with a slew of incentives to attract investments. It permitted setting up of wind and solar power projects of any size while allowing 100% Foreign Direct Investment (FDI) in such projects (GoI, 1992). The first major policy impetus for the RE sector came in 1993 with the then Ministry of Non-Conventional Energy sources (MNES) (now Ministry of New and Renewable Energy (MNRE)) laying out tariff recommendations for states, advising them to price renewables

at a minimum of ₹ 2.25/kWh (1994–95 as base year) with an annual escalation of 5% for 10 years (MNES, 1993). It announced incentives like 100% Accelerated Depreciation (AD) and annual energy banking. Accelerated depreciation allows for depreciation of fixed assets at a faster rate early in their useful lives, thereby reducing taxable income in initial years and deferring tax liabilities of profit making companies. Energy banking refers to an incentive for captive plants and Open Access (OA) transactions where excess generation can be notionally banked with the host distribution company (DISCOM) and be offset at a later time during the banking period which is usually one year. This is especially important for wind power given its seasonal generation profile. It also allowed third party (non-utility) sale of power by RE generators within the state with a uniform wheeling rate of 2% of energy fed into the grid. These guidelines were to remain in effect for five years. Based on this, various states came out with their policies and incentive schemes. These incentives resulted in strong national growth in the wind sector (from 41 MW in 1992 to 1,340 MW in 2002). In 2002, an Income Tax holiday was instituted offering a ten-year tax holiday for all infrastructure/power projects, which has been extended till 2017. The AD incentive, especially with respect to wind power, has undergone various changes over the years, which are captured in Table 4.1.

Table 4.1: Evolution of the Accelerated Depreciation incentive

Year	Changes in the AD Incentive
1993–2002	Introduced at 100% for both Wind and Solar
2002–2012	Reduced to 80% for both Wind and Solar
2012–2014	Reduced for Wind at 15% (with additional 20% on power equipment)
2014–2017	Reinstated to 80% for Wind (IANS, 2014)
April 2017 onwards	Proposed to be capped at 40% (Jai, 2016)

The AD benefit has two important shortcomings. Firstly, it only incentivises setting up of wind/solar capacity and has no link to actual generation performance; and secondly, it can only be availed by profit making companies to offset their tax liabilities. Hence, a Generation Based Incentive (GBI) scheme was launched in December 2009 for wind power with the objective of:

- broadening the investor base and creating a level playing field between various classes of investors,
- incentivising higher efficiencies, and
- facilitating entry of large Independent Power Producers (IPPs) and foreign direct investors in the wind power sector (MNRE, 2009).

From December 2009 to April 2012, it proposed to support 4,000 MW with an incentive of ₹ 0.5/kWh and a cap of ₹ 62 lakhs/MW in addition to the state regulated preferential tariff. Naturally, one could only avail one of the two incentives at any given time, AD or GBI. This incentive enabled the growth of the wind IPP sector in India. While it was discontinued in 2012, it was reintroduced in September 2013 to support 15,000 MW with the same incentive of ₹ 0.5/kWh but a higher cap of ₹ 100 lakhs/MW (MNRE, 2013).

To pass on the benefit of the AD incentive to DISCOM consumers, regulators started specifying two types of wind tariffs. For investors who were availing the AD benefit, they specified a lower wind tariff (to the extent of the AD benefit), while for IPPs who could not avail the AD benefit they specified a higher wind tariff. This higher wind tariff should have put IPP investors and AD investors on a level playing field. In practice however, IPP investors not only got the higher wind tariff, but could also avail the GBI benefit, resulting in double counting.

4.2.2 Legal, policy and regulatory instruments

The major legal reform which would catapult renewables towards their eventual mainstreaming was the Electricity Act of 2003 (specifically, Section 86 (1) (e))[6] which mandated the State Electricity Regulatory Commissions (SERCs) to promote RE through, amongst other things, specific targets (MoLJ, 2003). These targets set by SERCs, also known as Renewable Purchase Obligation (RPOs), mandate DISCOMs and other obligated entities like open access and captive consumers to procure a minimum fraction of their overall electricity consumption through RE[7].

Subsequently, two policies, namely the National Electricity Policy (NEP), 2005 (MoP, 2005) and the National Tariff Policy (NTP), 2006 (MoP, 2006) (as per provisions of the Section 3 of E Act) operationalised some of the E Act provisions with respect to renewable energy. The NEP noted that RE is environmentally friendly and needs promotion for its sustained growth, but efforts need to be made to reduce costs by promoting competition within such projects. It advised the SERCs

6. It states that the state ERC shall "promote cogeneration and generation of electricity from renewable sources of energy …, and also specify, for purchase of electricity from such sources, a percentage of the total consumption of electricity in the area of a distribution licensee."

7. Based on various appeals questioning the validity of RPO applicability to Open Access (OA) and captive consumers, the judiciary repeatedly directed that such RPOs are applicable to them and not just to the DISCOMs. The Gujarat High Court (12th March 2015 in the case of Hindalco (Birla Copper) and others), the Rajasthan High Court (31st August 2015 in the appeal by Hindustan Zinc Ltd., Ambuja Cements Ltd., Grasim Industries Ltd. and 14 other companies) and finally the Supreme Court (13th May 2015 order in Hindustan Zinc Vs. RERC) have all upheld the applicability of RPOs on OA and Captive Power Plant (CPP) consumers.

to progressively increase RPOs and to set a tariff with appropriate differential with respect to conventional sources for such procurement of RE till such time that it could be procured through bidding and compete with conventional sources. The NTP advised SERCs to take into account availability of renewable resources in the region and its impact on retail tariffs while setting RPOs. It too recommended RE procurement by DISCOMs to be done at preferential tariffs till they became competitive with conventional sources.

Based on these legal and policy directives, nearly all SERCs came out with RPOs and RE tariff regulations based on which yearly state and technology specific RE tariffs and RPOs were put in place. These state and technology specific preferential tariffs are also known as feed-in-tariffs (FiTs). They are essentially generic regulated cost-plus tariffs which typically include a 16% post-tax return on equity. Price (feed-in-tariffs) and Quantity (RPOs) are the two critical parameters for RE procurement. Ideally, price and quantity cannot be both fixed simultaneously, since it leads to the issue of fair project selection in case there are generators willing to sell more than the minimum quantity (RPOs) at the regulated feed-in-tariff.

As the sector kept growing, another major reform in the sector was the introduction of the Renewable Energy Certificate (REC) mechanism by the Central Electricity Regulatory Commission (CERC) in 2010 (CERC, 2010). The REC mechanism is a national regulatory instrument which allows for separating the environmental attribute (represented by the RE Certificate) of the renewable electricity and facilitating its trade through Power Exchanges. The important objectives of the REC were overcoming geographical renewable resource mismatch between states[8], facilitating RPO compliance, promoting new investments and capacity addition in renewables under a different mechanism in states with high RE potential.

4.2.3 National Action Plan on Climate Change and National Solar Mission

The next push for renewables, especially for solar, came from the National Action Plan on Climate Change (NAPCC), 2008, which suggested a national RE target[9] of 5% of electricity generation in 2009–10 rising at 1% each year to reach 15% by 2020 (GoI, 2008). While this was not binding on the states, it nonetheless significantly raised the importance of renewables and put down an indicative national target for 2020. It also went on to add that procurement be based on competitive bidding (CB).

8. Most of the wind potential in India is located in southern and western states. While solar potential is spread across all states, the better resource sites are in western India.

9. This target was for renewables excluding a) hydropower with storage capacity in excess of daily peaking capacity, or b) based on agriculture based renewable sources that are used for human food.

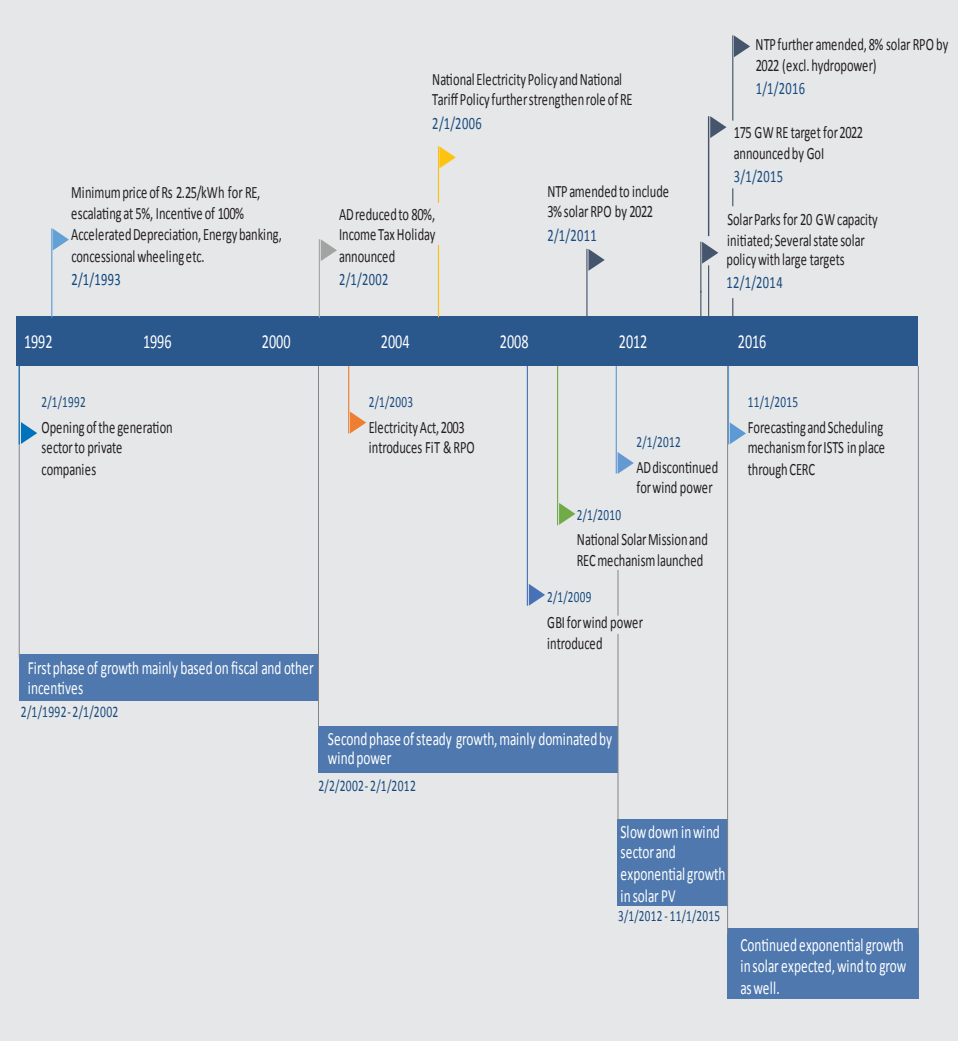
As part of the NAPCC, the Jawaharlal Nehru National Solar Mission (JNNSM) was launched in January 2010 "with an objective to promote ecologically sustainable growth while addressing India's energy security challenge and constituting a major contribution by India to the global effort to meet the challenges of climate change". It aimed at making India a global solar leader and accelerating the move towards the holy grail of 'grid parity'. Consumer grid parity (socket parity) occurs when an alternative energy source (generally some renewable source) can generate power at a cost that is less than or equal to the consumer electricity tariff from the central grid. Generation grid parity occurs when alternative energy sources can generate utility scale power at a cost that is less than or equal to the cost of generation from new power plants based on conventional technologies such as coal etc. The mission originally had targeted a capacity of 20 GW by 2022 for utility scale and rooftop projects (MNRE, 2009a).

An important break from existing policy was to move away from a regulated feed-in tariff to a competitive bidding based procurement under the solar mission. The original mission target warranted an amendment in the NTP in 2011, which prescribed the SERCs to separately fix non-solar RPOs (which would include wind, biomass, small hydropower, etc.) and solar RPOs beginning with 0.25% by 2013 and going up to 3% by 2022 (MoP, 2011). In 2015, the national solar target was revised to 100 GW by 2022 and hence the NTP was further amended in January 2016, and it now recommends to the SERCs to set solar RPOs to reach 8% of total consumption of energy, (excluding hydropower) by March 2022 (MoP, 2016).

4.2.4 Clean energy funds

The need to support renewable energy growth led some states to come up with special clean energy funds. In 2006, Maharashtra became the first state to start a renewable energy fund by levying a cess of ₹ 0.04/kWh on commercial and industrial electricity consumers which was later doubled. The fund (Urjaankur Nidhi) is used to support RE infrastructure development in the state as well as have equity investments in RE projects (Nidhi Jamwal, 2008). Considering the rising pollution levels, the GoI established the National Clean Energy Fund (NCEF) as per the 2010–11 budget to give "a positive thrust for development of clean energy", and was supported through a levy of a clean energy cess of ₹ 50/tonne of coal (domestic and imported) (MoF, 2010). This was increased to ₹ 100/tonne in 2014 and ₹ 200/tonne in 2015. (Bhaskar, 2015) The 2016 budget further doubled it to ₹ 400/tonne, which is expected to garner roughly ₹ 32,000 crores/year from 2016–17 (Sinha, 2016).

Figure 4.2: Timeline of major reforms in the RE sector from 1992–2016



4.3 Wind power

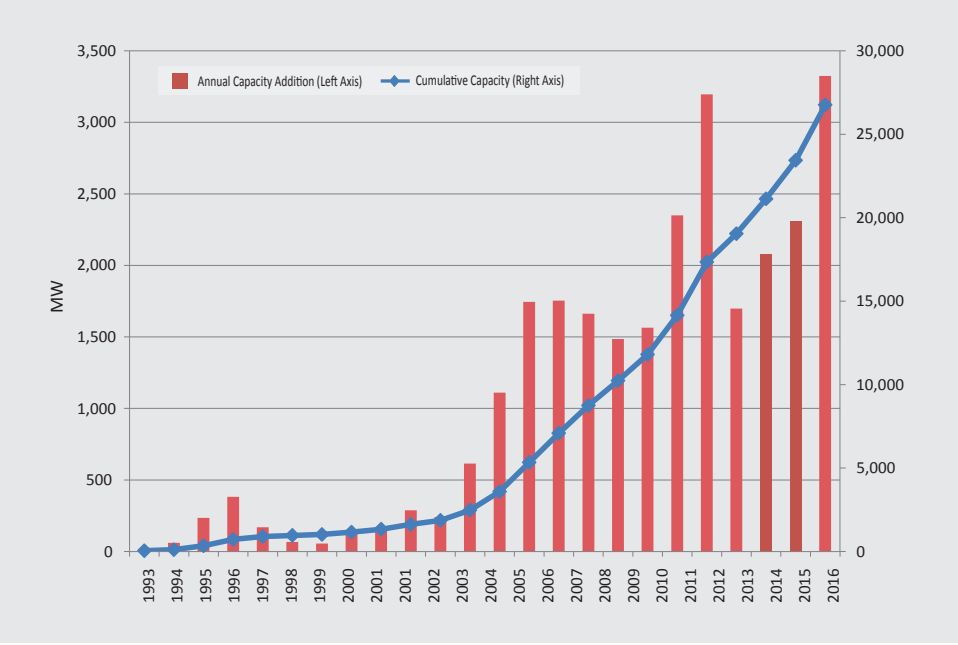
Wind power was the first commercially successful renewable energy technology to get established at a large scale in India. Deployment began in the early 90's and one can categorise the sector's growth over the years into four distinct phases of development, driven by the type and availability of incentives. These are summarised in Table 4.2.

Table 4.2: Wind power capacity addition in different time periods

Period	Reforms	Capacity (MW) installed over the said period	Average Annual Capacity installed (MW)
1992-2002	Excise, customs, tax incentives; 100% AD, Third party sale, concessional wheeling and banking. Driven by small investors mainly in Tamil Nadu and Maharashtra	1,587	159
2002-2007	E-Act introducing RPOs & FiTs	5,466	1,093
2007-2012	Additional incentive of GBI, REC mechanism, Open Access (OA)	10,259	2,052
2012-2015	Withdrawal and tempering of GBI and AD, emerging IPP sector	6,091	2,030
2015-2022	Targeted capacity	36,500	5,214

Source: Prayas (Energy Group) analysis based on various sources.

Figure 4.3 Growth of wind power capacity (MW) in India from 1993–2016



Source: Ministry of New and Renewable Energy.

Wind power generation has increased from 6 BU in 2005–06 to 33 BU in 2015–16, with installed capacity being around 28.2 GW as of October 2016 (MNRE, 2014; MNRE, 2016; MNRE, 2016a). The annual capacity addition and cumulative capacity from wind power at the national level can be seen from Figure 4.3. Just seven states dominate the wind map of India. Tamil Nadu and Maharashtra contribute roughly 50% of this capacity, while five more states, namely Gujarat, Karnataka, Rajasthan, Madhya Pradesh and Andhra Pradesh, make up the remaining 50% of the overall wind capacity in the country. These are also the states with most of the wind energy potential in India. Latest official estimates put the Indian wind resource potential at 100 m height at 302 GW[10] (NIWE, 2015).

4.3.1 Targets

Non-solar Renewable Purchase Obligations notified by SERCs have been an important regulatory instrument behind the growth of wind power. Non-solar RPOs vary widely from state to state, from 1.58 – 14.75% with most states lying in the range of 5–10% (REConnect Energy, 2016).

4.3.2 Pricing and procurement

All utility procurement of wind power by states is carried out at the SERC notified feed-in-tariffs. This is in line with the tariff policy recommendation in 2006 to procure RE at *preferential tariffs* as renewables will take time to compete with conventional power. Figure 4.4 depicts these state-wise FiTs for wind power. Some states have a single tariff for the entire state, while others have wind zone based tariffs, first introduced by the CERC in 2009. Tariffs in these states vary according to different wind resource classes, which are reflected in varying generation (Capacity Utilisation Factor) assumptions[11]. Wind zone based tariffs range from ₹ 3.21–6.6/kWh while tariffs in states with a single price range from ₹ 4.16–6.58/kWh (Figure 4.4). CERC also introduced the concept of indexation for determining year on year capital costs of RE technologies needed for tariff determination[12]. Another partly regulated pricing mechanism for wind power is through the REC mechanism, which is detailed in Section 4.5.4, *Renewable Energy Certificate Mechanism*.

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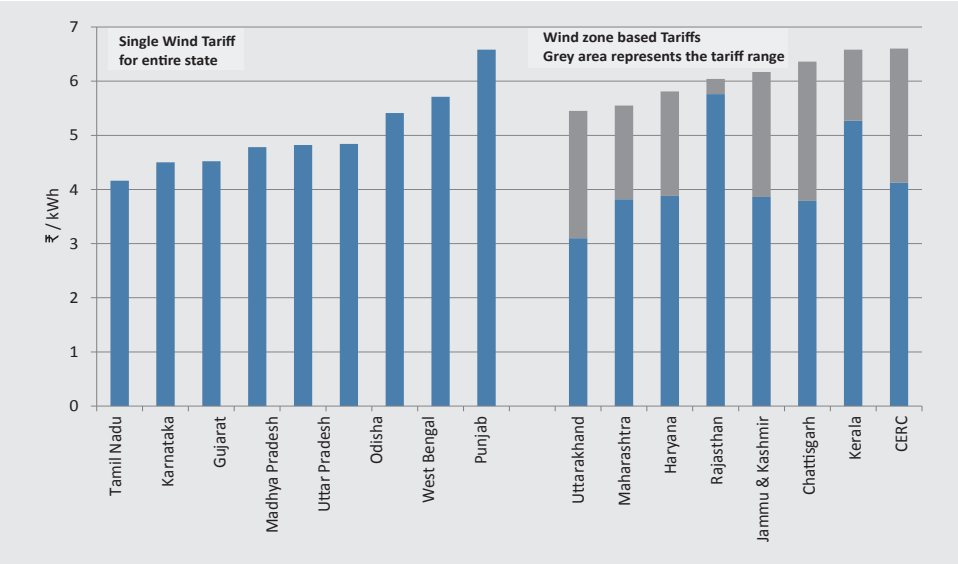
10. Earlier estimates of India's wind potential were 102 GW (at 80m) and 45 GW (at 50m).

11. For example, in Maharashtra, the MERC has specified a wind tariff for 2016–17 assuming a capital cost of ₹ 6.08 crore/MW to be ₹ 5.56/kWh (in wind zone 1 with CUF of 22%) and ₹ 3.82/kWh (in wind zone 4 with CUF of 32%). In Rajasthan, the tariff varies according to the geographical location instead of wind zones.

12. A wholesale price index (inflation factor) of steel and electrical machinery is used in calculating year on year capital costs from a base year.

Figure 4.4: Wind feed-in-tariffs in Indian states, May 2016



Source: Prayas analysis based on various state regulatory wind tariff orders.

4.3.3 Wind industry structure

The small scale of operations in the early years, absence of specialised entities executing various steps of a wind power project's value chain (resource assessment, land procurement, wind turbine manufacturing, engineering procurement construction (EPC), O&M etc.) and the kind of prevalent incentives resulted in a unique vertically integrated market structure with turbine manufacturers doing turnkey projects for investors. While this was understandable in the early years, its continued existence is to a large extent is in stark contrast with the wind industry structure in the rest of the world[13]. This peculiar Indian structure has resulted in a lack of competition to a certain degree[14] within the wind industry till now. This is mainly due to the lack of wind resource data in the public domain, which creates an entry barrier for investors and companies which do not have access to land with good wind resources, thereby limiting competition. In the last few years, especially with the introduction of GBI, the industry structure is gradually becoming more competitive with the emergence of IPPs such as Renew Power, Welspun, Bharat Light and Power, CLP, Mytrah Energy, Green Infra, and Orient Green Power. Some

13. Turbine manufacturing companies are not involved in project development. Specialised companies carry out wind resource assessment, EPC, O&M, etc.

14. However, it is not the case that there is absolutely no competition in the wind sector in India. PSUs invest in wind power in a tendering based competitive manner.

of them have also invested in their own wind resource assessment programmes. IPPs tend to have much larger project sizes compared to individual investors and a greater focus on performance given the availability of incentives like GBI.

The lack of an overarching national policy laying down a clear long-term vision for the sector has resulted in the sector at times being caught up in a somewhat myopic and vicious circle of short-term and immediate considerations. This is especially clear from the fact that wind power installations dropped significantly from 3.2 GW in 2011–12 to 1.7 GW in 2012–13 when the AD and GBI incentives were discontinued. Even after nearly 20 years of experience, the sector has unfortunately been unable to break out into the next cycle of growth where it should be aiming to deploy 5–6 GW/year without relying on incentives to meet the 60 GW target.

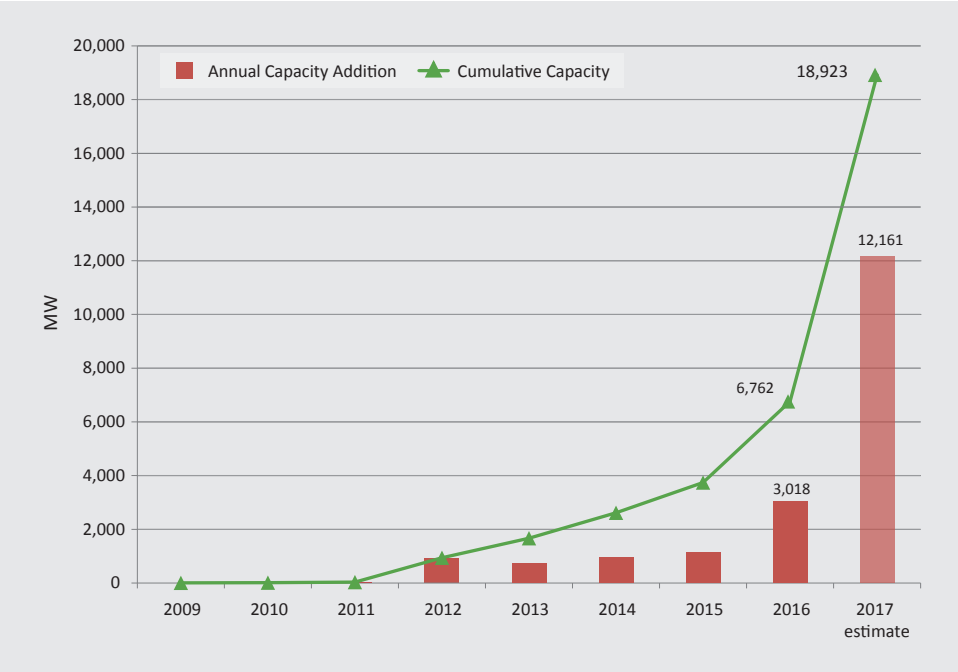
With regard to manufacturing, there are about 20 manufacturers with over 50 turbine models available in the Indian market in 2016, ranging from 225 kW to 3000 kW, and with varying hub heights and rotor sizes designed for different wind regimes (NIWE, 2015a). There has been a strong trend towards larger capacity machines with higher hub heights and larger rotors (both well over 100 m in some of the latest turbines) to essentially exploit low wind resource sites and produce more electricity at lower costs (Ramesh, 2015). While the country's overall wind manufacturing capacity is roughly 12 GW/year, it remains significantly underutilised (CSTEP & WISE, 2016).

4.4 Solar power

The story of large grid connected MW scale solar power plants began in India in 2009 with the initiatives of the Government of India under the National Solar Mission, which initially set a target of 20 GW by 2022, and the Gujarat Government under its 2009 state solar policy (Government of Gujarat, 2009). Subsequently various state governments have come out with policies to support solar power. Figure 4.5 shows actual year-wise solar capacity addition till March 2016 and estimates for 2016–17. India has 8,727 MW of installed solar capacity as of October 2016 of which the bulk is photovoltaics (PV) based, and only 205 MW is based on thermal Concentrating Solar Power (CSP) (MNRE, 2016). Tamil Nadu and Rajasthan are the leading states with 1,555 and 1,301 MW installed respectively. Gujarat ranks third with 1,138 MW. While the MNRE estimate (as of January, 2016) was that 12 GW of capacity would be installed in 2016–17, some industry estimates peg it much lower at 5–6 GW due to potential project delays and possibilities of over-aggressive bidding[15].

15. Subsequently, as of November, 2016, MNRE has revised its capacity deployment estimate for 2016-17 to 11 GW.

Figure 4.5: Growth of solar power (MW) in India from 2009–2016 (actuals), estimates for FY 16-17



Source: Ministry of New and Renewable Energy, (MNRE, 2016b).

Looking ahead, there is a healthy pipeline of 23 GW of solar projects with 15 GW wherein bids have been submitted and 8 GW where bids are still pending (BridgetoIndia, 2016a). Around 12.5 GW of solar capacity can be categorised as work in progress (BridgetoIndia, 2016)[16]. A significant share of future solar capacity addition can be attributed to investments/development by Public Sector Units (PSUs) and central government companies such as National Thermal Power Corporation of India (NTPC), Solar Energy Corporation of India (SECI), Indian Oil Corporation (IOC), Indian Railways, port authorities, defence establishments, etc.

While the year-wise solar power generation for the entire country is not available in a consolidated form in the public domain, performance from early projects indicates a realisable Capacity Utilisation Factor (CUF) of ~21%[17] (MNRE, 2014a).

16. Most of the pipeline activity is in Telangana (2,263 MW), Karnataka (2,254 MW) and Andhra Pradesh (2,687 MW). Other emerging states are Madhya Pradesh, Punjab, Uttar Pradesh, Maharashtra and Haryana.

17. Batch-1 and Batch-2 projects under the JNNSM Phase-1 reflect an average achievement of 20.75% and 21.04% CUF for crystalline silicon and thin film projects respectively.

4.4.1 National and state level solar targets

The dramatic fall in solar PV prices coupled with good quality solar resource (practically limited only by land availability) has reflected in ever increasing solar targets for the country, as detailed in Table 4.3. The five-fold increase in the solar target from 20 to 100 GW by 2022 implies a need for significant growth of 60% (CAGR) from 2015 to 2022 in terms of capacity addition. However, existing mandatory solar RPOs set by SERCs range from 0.25–6% and in most states are actually between 0.25–2.5%. (REConnect Energy, 2016) These will now have to be significantly revised upwards after the January 2016 amendment of the national tariff policy which now recommends to the SERCs to set solar RPOs to reach 8% of total consumption of energy, excluding hydropower, by March 2022 (MoP, 2016). The MNRE has already initiated steps asking states and SERCs to bring out an action plan for this purpose (MNRE, 2016c).

Besides, Rooftop Solar PV (RTPV) is also expected to play a key role in future solar capacity addition, with 40 GW out of the proposed 100 GW expected to be added through RTPV installations. Over 27 states and union territories have already formulated policies and regulations and put in place a framework for net metering.

Table 4.3: Evolving solar targets (in MW) for 2022

Policy Targets	Original National Solar Mission 2009	National solar requirement as per NTP amendment in 2011, requiring 3% solar by 2022	Addition of state policy targets as of February 2016	Revised national solar target announced in 2015 Union Budget	Broad national solar requirement as per NTP amendment in 2016, requiring 8% solar by 2022 excluding large hydropower (assuming demand as per 18th EPS)
Year	20,000	34,000	58,931	1,00,000	85,000

Source: Prayas (Energy Group) analysis based on various sources.

4.4.2 Pricing and procurement

Just like the wind sector, solar procurement in its initial years was based on Feed-in-Tariffs (FiTs). The first large scale state procurement was done in Gujarat at a FiT of ₹ 10.37/kWh (₹ 9.27/kWh with accelerated depreciation) for ~850 MW (well beyond the policy target of 500 MW) on a first come first served basis, and projects were completed in 2012–13. The first central procurement under the JNNSM was also planned at FiTs set by the CERC (₹ 17.91/kWh for 2010–11). However, considering the over subscription for the allocated capacities, the JNNSM moved

towards a reverse competitive bidding based procurement with projects allocated to those offering highest discounts on the CERC FiT. Under the Batch-1 and Batch-2 JNNSM projects (Phase 1), a 32% and 43% cost reduction was possible through the reverse bidding process over the CERC benchmark tariffs of 2010–11 and 2011–12 respectively (Deshmukh Ranjit, 2011). The total lifetime savings for the roughly 1000 MW capacity were ~ ₹ 7300 crores[18].

The solar PV sector has been in an extremely dynamic phase of evolution since 2010, both with regard to technology and prices. With limited reliable Indian solar cost and performance data available in the public domain, coupled with the inherent information asymmetry, it has always been a challenge for ERCs to set appropriate preferential tariffs, which are not too low to not attract any investors or too high to result in excessive retail tariff impacts on the consumers[19]. This contrast can be seen from Figures 4.6 and Figure 4.7 which depicts the year wise regulated FiTs set by the CERC and the prices discovered under the competitive bidding route under the JNNSM and various state policies respectively. Understandably, most states have followed up on the success of competitive bidding (despite initial scepticism) first experienced under the JNNSM[20] with their own bidding based procurement. This has allowed Indian consumers to reap the benefit of global reduction in solar PV equipment prices and in turn resulted in significant savings for the electricity consumers. The lowest bid thus far, at ₹ 4.34/kWh for 70 MW capacity to be set up in a Rajasthan solar park and procured by NTPC, has heightened the expectation of grid parity to be attained much sooner than later. The response to most bidding rounds has been extremely positive, indicating a highly liquid market. The relative surety of the solar resource[21], associated land availability and more or less even resource spread unlike the high site-specificity of wind, lower ticket sizes in the

18. NPV of savings @10% discount rate.

19. This is brought out by the recent experience in Gujarat, wherein the Gujarat Urja Vikas Nigam Limited (GUVNL) petitioned the Gujarat Electricity Regulatory Commission (GERC) to revise the solar PV tariffs from ₹ 12.54/kWh to ₹ 9/kWh for projects already commissioned and with whom PPAs were signed, citing that project costs were much lower in reality than those that were considered by the GERC while determining tariffs. The GERC dismissed this petition in August 2013, and its stand was subsequently upheld by the Appellate Tribunal for Electricity (APTEL) in August 2014.

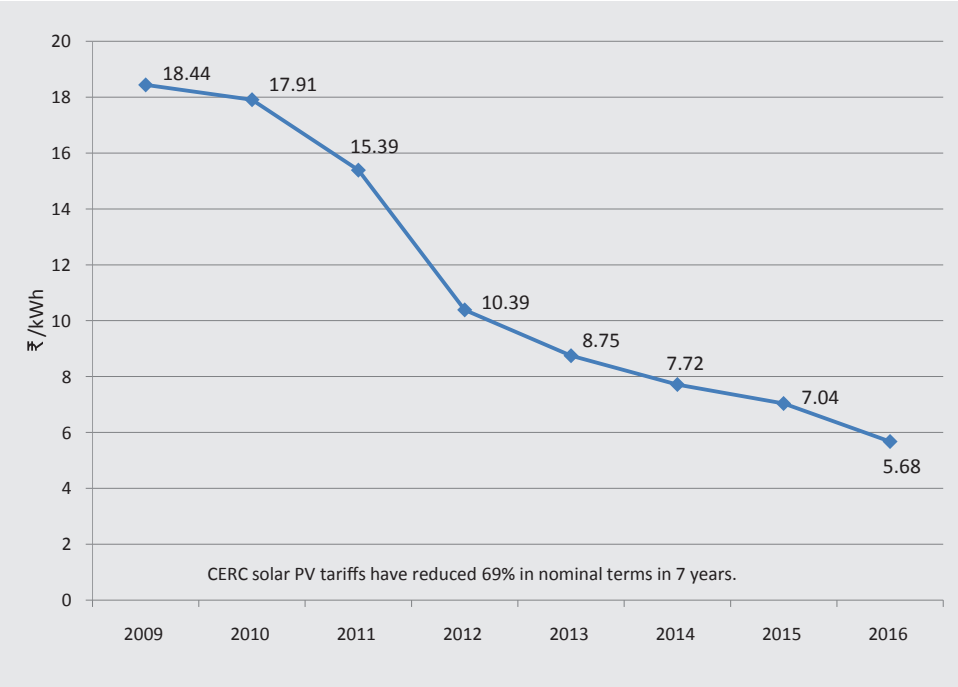
20. The incentives of central procurement and payment risk guarantee fund reduced risks for private bidders under the JNNSM. Bundling with cheap NTPC coal power and subsidised solar tariffs under the Viability Gap Funding mechanism made solar power a relatively more attractive option for DISCOMs.

21. For CSP, the bidding process has not been all that effective. The lack of experience with the technology, its procurement, higher costs, limited manufacturing capacity and the underlying resource quality has led to a significant delay in Phase-1 projects under the JNNSM going online. Only 205 MW of the 470 MW bid have been commissioned till 2016. Some winning developers have even appealed to the CERC to reopen the PPAs citing price increase due to the lack of reliable resource data.

initial bidding rounds, low gestation periods, confidence in the transparent bidding process, and the price reductions (past and expected) have all contributed to the success of competitive bidding. Global manufacturing and the presence of a large number of players in addition to the above factors has meant that the solar sector has been somewhat structurally competitive right from the start, and this has resulted in greater emphasis on cost reduction and performance. While every once in a while there have been demands for feed-in-tariffs based solar procurement, the JNNSM and most states are prudently sticking to competitive bidding. (Krar, 2016)

A 100 GW solar target in comparison to the 60 GW target for the more established wind power sector points to the greater public acceptability for solar PV and the expectation of future cost reductions. A 2015 report estimates utility scale solar PV generation costs to be ₹ 4.2/kWh and ₹ 3.59/kWh[22] (in 2015 rupee terms) in 2020 and 2025 respectively (KPMG, 2015).

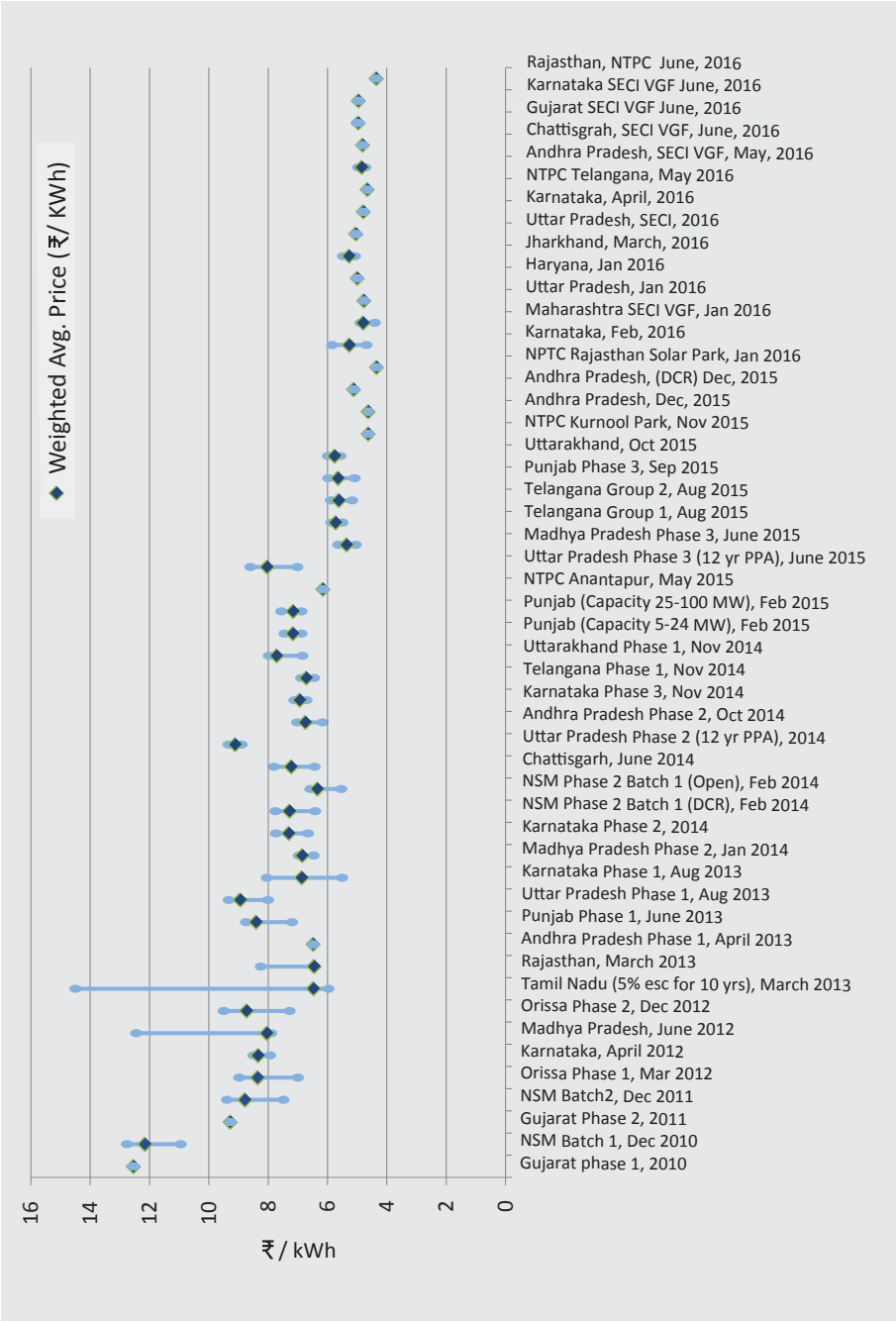
Figure 4.6: CERC solar PV tariffs (₹/kWh) from 2009–2016



Source: Central Electricity Regulatory Commission.

22. These are pure generation costs and do not include grid integration costs which have been broadly estimated by the same report at ₹ 0.23/kWh in 2020 and sharply rising to ₹ 1.3/kWh in 2025.

Figure 4.7: Year-wise evolution of competitively discovered solar PV tariffs in India from 2010-2016



Source: Prayas analysis based on information from MNRE, various news items, (BridgetoIndia, 2015), (BridgetoIndia, 2015b). Note: All SECI Viability Gap Funding (VGF) based bids for 2016 have a ceiling price of ₹ 4.43/kWh. Tariffs shown here include the VGF support.

4.4.3 Industry structure

As of April 2016, the country had a solar PV manufacturing capacity of 1,212 MW and 5,620 MW of cells and modules respectively, but continues to lack any capacity in regard to poly-silicon and wafer production (MNRE, 2016d). The limited domestic manufacturing capacity could not immediately provide for large scale PV projects to come under the JNNSM, prompting policy makers to allow imported equipment. This policy decision combined with the inherent nature of solar energy, i.e. (a) its modular nature allowing projects from few kWs to few MWs to even at a GW scale now, (b) fair understanding of the solar resource and lack of variation over fairly large areas leading to low entry barriers for land, and (c) relatively easier system integration and low gestation, even for large projects, opened up the solar PV sector to strong competition from a vast number of players in all segments of the value chain right from the beginning. As a result, the solar sector did not develop as a vertically integrated structure unlike the wind sector.

4.4.4 Solar parks

To facilitate the faster and planned growth of large scale utility solar PV power plants, the GoI has introduced a programme for the development of solar parks and ultra-mega solar power projects. These parks will have appropriately developed land with all clearances, transmission systems, water access, road connectivity, communication networks, etc. As of March 2016, 33 solar parks are slated to come up in 21 states with a capacity of 19.9 GW (Mukul, 2016). MNRE provides central financial assistance for preparing the DPRs as well as 20 lakhs/MW for developing such solar parks, but the responsibility for land identification and making it available lies with the states (MNRE, 2014b). The GoI is also promoting so called 'solar zones' which will be similar to solar parks, but the onus of land procurement would lie with private developers (Prasad, 2015). While such planned solar parks with some element of GoI subsidy should significantly lower the costs and risks for projects, one analyst points out that the high charges being levied by some Solar Park Implementation Agencies for leasing land in the solar park may prove counterproductive to the overall aim of lowering solar prices (BridgetoIndia, 2015a).

4.4.5 Rooftop Solar PV

Rooftop Solar PV (RTPV) projects are relatively smaller scale onsite generation projects connected to the low voltage distribution grid and mainly used to partly offset one's own electricity consumption. While the 2022 target for rooftop solar has been set at 40 GW, the installed capacity is only 740 MW by March 2016

(BridgetoIndia, 2016). Hence achieving this target in the given time frame (~ 50 times existing capacity) is extremely ambitious considering the smaller size of individual projects and higher transaction costs. Up until 2012–13, when solar costs were still relatively high and consumer tariffs were lower than what they are today, it did not make financial sense for most consumers to install such systems. Hence the MNRE had a capital subsidy (30% of benchmark capital costs) programme in place to incentivise consumers. Yet, it made more sense for commercial and industrial consumers to adopt solar in comparison to residential consumers given their higher tariffs and relatively higher availability of shadow free rooftop space. As solar prices continued to plummet, many states through their policies and SERC regulations began facilitating RTPV adoption through the mechanism of 'net metering'. Net metering is a billing mechanism which allows energy banking and credit for excess solar electricity fed into the distribution grid by the project. At the end of the billing period, the consumer has to pay for the 'net' electricity consumed (difference between electricity consumed from the grid and electricity fed into the grid from the solar project). If the amount of electricity fed into the grid is more than that consumed from the grid, the excess is carried forward to the next billing period. This has proved to be a crucial incentive for consumers to adopt rooftop systems and now 27 states and union territories have some form of net metering system in place (BridgetoIndia, 2015b).

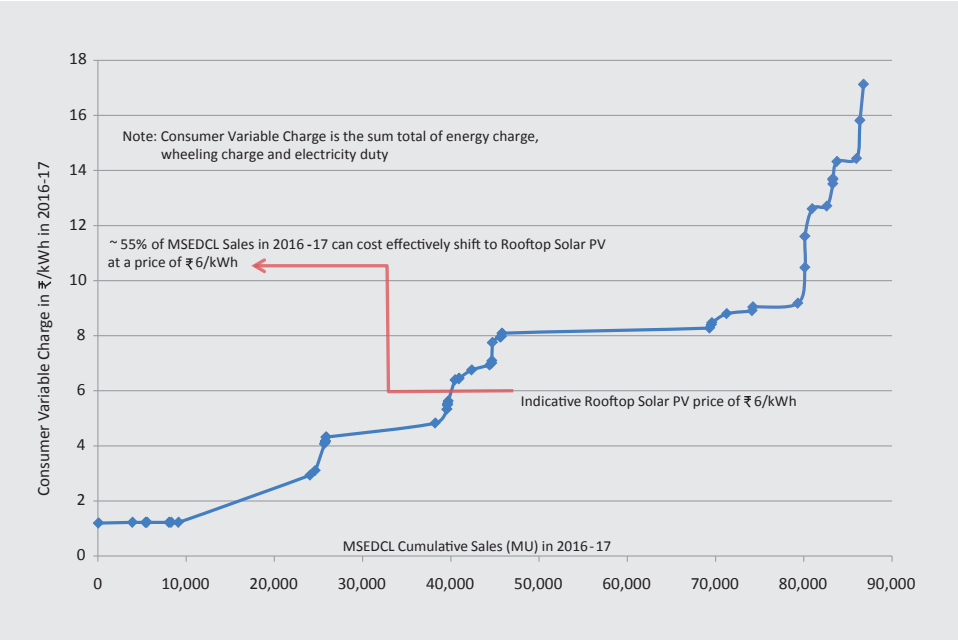
As consumer tariffs, especially for industrial and commercial segments, continued to rise over the years while solar costs kept coming down, the MNRE reduced the capital subsidy from 30% to 15% and limited its applicability to only residential, institutional, government and social sector entities in August 2015 (MNRE, 2015). However, within three months, the MNRE reinstated the earlier norm of 30% capital subsidy but now has excluded government entities from this ambit (MNRE, 2015a) (MNRE, 2016e). For government entities including PSUs, the MNRE has brought in an "achievement-linked incentive and awards scheme" instead (MNRE, 2016f). The MNRE has also managed to get a substantial increase in the overall allocation for rooftop capital subsidies at ₹ 5,000 crores for 2015–2020 (MNRE, 2016g). Apart from the capital subsidy, the MNRE has facilitated RTPV adoption through other financial incentives as well. These include mandating banks to provide loans for rooftop solar as part of home loans, concessional interest rates from the Indian Renewable Energy Development Agency (IREDA) for system aggregators, and loans under priority sector lending status (MNRE, 2014c; RBI, 2015).

The Solar Energy Corporation of India (SECI) has been piloting rooftop systems in various cities throughout India wherein project developers are selected through a transparent bidding process. Projects can be set up under one of two business models, a) CAPEX model wherein developers bidding the lowest capital cost and hence subsidy requirement win the project. The project is built by the developer and then handed over to the investor/owner. B) Renewable Energy Service Company (RESCO) model wherein developers bidding the lowest electricity tariffs (in ₹/kWh after accounting for a fixed subsidy amount) win the project. Here not only do the developers have to invest and build the project, they also have to maintain it over the life of the power purchase agreement with the consumer. Winning bids from few SECI tenders indicate a price range of ₹ 64–85/Wp for the CAPEX model, while the RESCO model has seen levelised tariffs between ₹ 4.72/kWh to 6.68/kWh (after accounting for the 30% subsidy) (SECI, 2014; SECI, 2015). The second model is ideal for the consumer who does not have to invest his capital, neither has to worry about O&M and project quality. He only has to pay for the electricity on a metered basis. Given the high commercial and industrial tariffs, adopting RTPV systems in fact saves money for such consumers from day one. Such business to business, third party innovative ownership models are already beginning to transform the rooftop solar segment and can quickly drive up installations.

However, DISCOMs have not been particularly supportive in operationalising 'net-metering', especially for commercial and industrial consumers (MNRE, 2016h). They have expressed apprehensions about rooftop solar systems on two fronts. Firstly, they are concerned about the cumulative impact of a large number of rooftop systems on the distribution grid, in terms of reliability, power quality and safety. However, evidence from countries with high penetration of rooftop solar systems demonstrates that these concerns are addressable with appropriate strengthening of the distribution system, which is acutely needed in India independent of rooftop solar (PEG, 2014b). Secondly, they are rightly worried about the impact this will have on their already precarious financial situation as they lose part of their sales from high paying consumers shifting to solar, especially since this transaction does not attract any cross-subsidy surcharge payment to the DISCOM. This is exemplified from Figure 4.8 which shows that nearly 55% of Maharashtra State Electricity Distribution Company (MSEDCL) sales can cost-effectively move to RTPV provided such roof space exists. It is critical that a fair and equitable sharing of costs and benefits between consumers adopting rooftop solar, the DISCOM, and its non-solar consumers needs to be worked out going ahead. Some possible

ways of this benefit sharing with the utility would be in the form of some grid fees and charges in lieu of the energy banking facility and avoided battery costs. Going forward, as the difference between solar costs and utility tariff potentially further widens, the ERCs could look at modifying the net metering rules to offer reduced prices for the banked energy. Finally, DISCOMs may also petition the ERC for increasing fixed charges for consumers, since in many states these are not reflective of fixed costs of the utility.

Figure 4.8: Solar rooftop viability in Maharashtra



Source: Maharashtra Electricity Regulatory Commission (MERC) tariff order for MSEDCL.

4.5 Issues and challenges

There is a broad consensus amongst policy and regulatory officials that renewables will have to play an ever increasing role in the power generation side of the sector. Despite this optimism, there remain several existing and potential upcoming challenges which need to be pro-actively dealt with, failing which the announced renewable energy targets may only end up as a pipe dream.

4.5.1 Renewable Purchase Obligation (RPO) target setting and weak compliance

There are three core issues with regard to renewable energy targets (RPOs).

Firstly, national renewable energy targets (15% RE by 2020 under NAPCC, 100 GW of solar power and 60 GW of wind power by 2022, a 10.25% non-solar RPO and 6.75% solar RPO by 2018-19 as prescribed by MoP) are only guiding or aspirational in nature and not strictly binding on states. Additionally, state targets (under their state government policies or as fixed by their respective SERC regulations) do not fully add up to the national target. This mismatch is to be expected to some extent given the lack of any principles for equitable sharing of the national target amongst all states, and considering their differing resource endowments, consumer mix, ability to pay and financial health of the DISCOMs, etc. States continue to remain unenthusiastic about increasing RPOs, given the existing higher direct costs of RE as well as what they perceive as its 'infirm' nature. They have in fact been demanding incentives from the GoI for RPO compliance as well as compensation for backing down cheaper thermal power plants to accommodate renewable power (MoP, 2016a). It also reflects a need for continuous engagement and deeper coordination between states and the centre while also highlighting their differing priorities, capabilities and constraints.

Secondly, while RPOs have been instituted by SERCs as required by Section 86(1)(e) of the E Act, not all have followed various policy guidelines in doing so. Some states do not have long term and increasing RPOs (e.g. Jharkhand, Chattisgarh, Tamil Nadu, Maharashtra), while almost all do not explicitly consider retail tariff impact while deciding RPOs.

Finally, the RPO compliance verification mechanism in most states is rather weak. Paucity of updated and comprehensive compliance data in the public domain is adding to the lack of accountability of the obligated entities. Not only have obligated entities not met their RPO targets in most years, in practice these targets are treated as ceiling targets, when in fact they are minimum targets.

Unfortunately, most SERCs have not taken a very strict approach towards compliance and have not invoked penal provisions as per their own regulations (CAG, 2015). A variety of regulatory practices have been followed in dealing with non-compliance. Some states (Gujarat, Rajasthan and Tamil Nadu) have reduced RPOs for subsequent years to match the actual achievements of previous years by obligated entities, while some (Gujarat, Maharashtra) have allowed carrying forward of non-complied RPOs on the condition of future cumulative compliance.

Box 4.1: Moving beyond Renewable Purchase Obligations (RPO) in the medium term

The need for separate RE targets (RPOs) arises as long as there is a lack of a level playing field for renewables (i.e. the cost of socio-environmental externalities of conventional power is not internalised), or till such time as there continues to be a direct price differential between RE and conventional power. One way to internalise certain externalities is to mandate stringent and time bound environmental norms for conventional power which can be further tightened over time. Such an effort has been started by the Ministry of Environment, Forest and Climate Change (MoEFCC) with regard to coal power (PIB, 2015). Another is to have an environmental tax, such as the coal cess, which now stands at ₹ 400/ton since 2016–17.

In parallel, RE prices (especially for solar PV) have come down drastically, and there is an expectation of further reductions in the future. Hence, in the medium term, as RE and conventional power prices begin to converge, policy and regulatory officials as well as DISCOMs should begin to include renewables as an integral part of the least cost planning exercise than continue with separate targets. Such an exercise could give some form of preference for RE for its environmental benefits (possibly through a higher weightage in the merit order stack) in line with the national vision of increasing the share of RE. However, on the other hand, it should also consider any added differential in system integration costs (e.g. higher balancing costs) arising due to RE. Estimating and attributing such RE specific integration costs is not an easy exercise. This is especially true of the relatively weak India grid which is seeing several grid strengthening initiatives underway for effective, reliable and secure operation of the grid, which are needed irrespective of whether the grid has a high penetration of variable renewables like wind and solar or not. However, these will also help ease the integration of renewables into the grid. While calculating differential in integrating costs arising due to RE, one needs to keep in mind that the assumptions for grid reliability and functioning should be normalised in both cases.

Most states have condoned non-compliance without questioning the lack of use of the REC mechanism set up specifically (in part) for such times. Non-initiation and delay of RPO compliance enforcement by SERCs is also quite common, while for non-DISCOM obligated entities, namely Captive Power Plant (CPP)/OA users, this is completely missing (ATE, 2015). Finally, there has been even a case of incorrect RPO accounting, when MSEDCL's RPO compliance estimation for FY 2010–11 and FY 2011–12 had included the RE power wheeled through its network under Open Access, a case of double counting.

DISCOMs have put forth some arguments for this lack of compliance, including low RE generation which is not in line with expected CUFs, non-availability of solar RECs in the early years, and delays in project commissioning (mainly solar PV). DISCOMs continue to request deferring the RPO targets by a few years (Verma, 2015). However, not using the REC mechanism and year on year non-compliance renders such arguments facile. The lack of RPO compliance from all obligated entities, especially the DISCOMs, is casting doubt on the robustness of the growth of renewables. However, in a 2015 APTEL judgement on the issue of RPO non-compliance, it observed that various SERCs are not complying with their own regulations (ATE, 2015). Henceforth, any carry forward of non-compliance or review permitted by the SERCs will have to be strictly as per their regulations while keeping in view the availability of RECs. It also urged SERCs to exercise penal provisions (for non-compliance) in their regulations. This is expected to improve compliance in coming years, a pre-requisite for sustained growth in the renewable energy sector.

4.5.2 Need for competitive bidding based price discovery in wind power

The relative lack of competition in the largely vertically integrated Indian wind industry (see Section 4.3.3) has partly contributed to a reluctance to move towards a competitive price discovery regime. Regulated wind Feed-in-Tariffs (FiT), while quite low a few years ago, have been steadily increasing in nominal terms (as seen in Figure 4.9) in contrast to global price trends (Weiner, 2015). This is in spite of the wind power capital costs in India being one of the lowest in the world. Apart from the industry structure, the feed-in-tariff regime in India is also different from say Germany, which is often cited as an example of the success of FiT. Firstly, strong competition within manufacturers in Germany is cited as one of the reasons for the success of the FiT mechanism, since turbine costs are the biggest part of the final electricity costs. Secondly, FiTs in India are not linked to any year on year

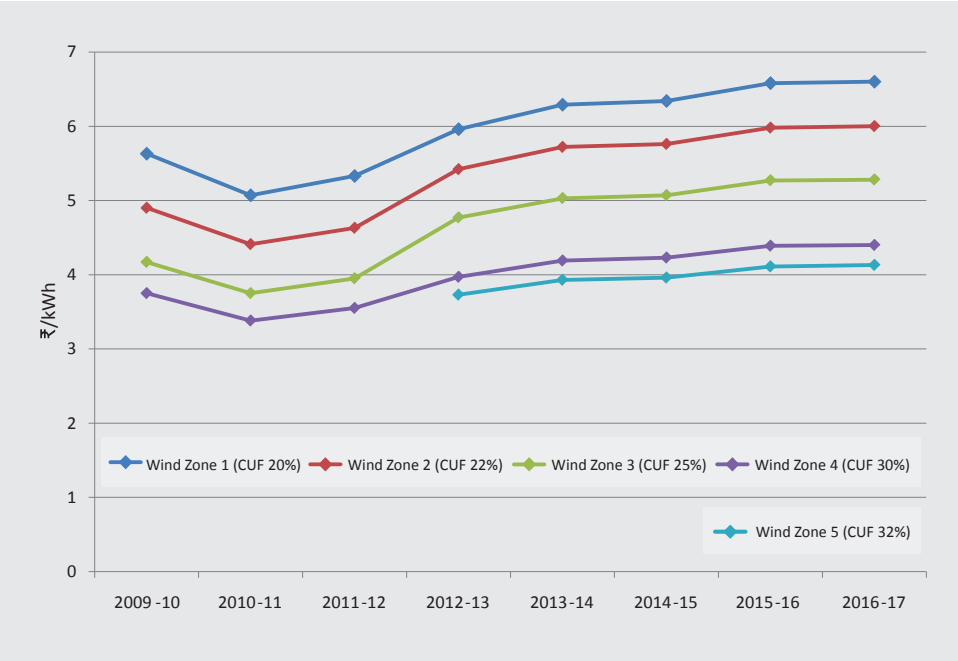
degression rates as is done in Germany. Another point of departure is the fixed period (usually 20 years) for FiT based PPAs in India, irrespective of actual realised CUF. This is in sharp contrast to the standard German feed-in-tariff practice where actual CUF and performance is taken into account to determine the time period for payments of FiTs[23].

Capital costs and CUF are the two most sensitive parameters while determining FiTs for wind power. Year on year capital costs are generally estimated by an indexation formula which accounts for the inflation in steel and electrical machinery prices, but is unable to capture technology (design, efficiency) and scaling (larger rotor and hub heights leading to higher CUFs) improvements, which have been significant in the past few years (Bolinger, 2011). A case in point is Maharashtra. The MERC's RE tariff regulations specified a CUF of 20% for areas with wind power density (WPD)[24] of 200–250 W/m2 at a 50 metre hub height, while also mandating a minimum WPD of 200 W/m2 (MERC, 2012). In 2011, a wind developer petitioned the MERC to allow it to go ahead with a project with a WPD of 193.9 W/m2, as certified by the National Institute of Wind Energy (NIWE). The company was expecting a CUF of 27.7% at this site (39% higher than the MERC estimate), largely attributable to a higher turbine hub height of 65m. The higher CUF (27.7%) results in a lower tariff of ₹ 4.58/kWh as against the then existing MERC notified tariff of ₹ 6.34/kWh for a CUF of 20% — which would have led to an unnecessary additional consumer burden of 38%. In its final order in this matter, the MERC agreed to "initiate suitable action to amend the MERC (Terms and Conditions for determination of RE Tariff) Regulations 2010 appropriately" (MERC, 2012). Subsequently, in March, 2013, while setting the renewable energy tariffs for 2013-14, under its powers for "removal of difficulty", it relaxed the norm of having a minimum WPD of 200 W/m2 (MERC, 2013). However it retained the hub height at which this WPD was to be measured at 50m and the corresponding CUF at 20%. Finally, in November, 2015 it notified its new renewable energy tariff regulations, wherein the CUF for any wind power site with a WPD up to 250 W/m2 at a height of 80m was fixed at 22% (MERC, 2015).

23. A FiT for wind power is calculated for a standard wind site (expected generation at the site is called the Reference Yield). This FiT is guaranteed initially only for five years. Depending on the actual generation in these five years (in proportion to the reference yield) the future time period for which this FiT is applicable is varied proportionately.

24. A measure of the wind resource quality.

Figure 4.9: CERC wind tariffs from 2009–10 to 2016–17



Source: Central Electricity Regulatory Commission.

Additionally, ERCs make single point assumptions for various financial parameters such as interest rates[25], return on equity expectations and the discount rates which are used in tariff calculations. In reality, there is a wide range of values for these parameters across investors, especially with increasing evidence of equity and debt investments from outside India. This shows the level of uncertainty and difficulty that regulators face in determining effective and appropriate FiTs.

Considering the rising wind power tariffs, difficulties in setting regulated tariffs and the DISCOMs reluctance to buy more expensive (upfront) power from variable resources like wind, the sector needs to move towards competitive price discovery and cost reductions. Competitive bidding, if designed and implemented well, can be an effective way to procure least cost wind power. It will also spur development on high wind resource sites rather than on those with relatively poor resources.

25. Wind and solar do not use any fuels and hence most of the cost of the electricity comes as an upfront capital expenditure and the associated cost of capital. Hence, interest rates and tenures play an important role in the final price. There is a reduction of ₹ 0.6/kWh and ₹ 0.4/kWh in the tariffs of solar PV and wind respectively (an 8% reduction) if the loan terms improve from a 14% interest rate with a 10 year repayment to a 8% interest rate with a 16 year repayment. Author's analysis and estimates.

This is important for India, given the financial health of our public utilities, which puts an added onus on policy makers and regulators to facilitate competitive price discovery. While some states as well as the GoI have tried to introduce competitive bidding based price discovery in the wind sector in the past (See Box 4.2), their efforts have not borne fruit till date.

Box 4.2: A journey towards Competitive Bidding (CB) for wind power in India

Gujarat: Gujarat Electricity Regulatory Commission (GERC) in its wind tariff order dated 11th August 2006 mentioned the possibility of adopting bidding as a means of tariff discovery but postponed the decision to the future.

Tamil Nadu: The Tamil Nadu Electricity Regulatory Commission (TNERC) noted that wind tariffs were competitive with conventional power, but the lack of RE specific bidding guidelines from the GoI under Section 63 of the E Act and the Supreme Court stay on the APTEL order on competitive bidding forced it to continue with the feed-in-tariff approach (TNERC, 2014).

Rajasthan: Both, the Rajasthan Electricity Regulatory Commission (RERC) Renewable Tariff Regulations, 2009 and the state wind and solar policies of 2011 contemplate tariff discovery through reverse bidding. The RERC tried to circumvent the absence of bidding guidelines from the GoI by carrying out the bidding through the Rajasthan State Nodal Agency, which would have in turn sold the power to the DISCOMs. However the new policy has reverted to feed-in-tariff based procurement. The RERC RE Tariff Regulations of 2014 allow for tariff discovery through competitive bidding only if done in accordance with the GoI guidelines under Section 63 of the E Act (RERC, 2014).

GoI: The MNRE has in the past twice put out draft bidding guidelines (under Section 63 of the E Act) for renewable energy procurement by DISCOMs in 2010 and 2012 and held stakeholder consultations but is yet to come out with final notified guidelines (MNRE, 2012). In June, 2016, MNRE initiated a process for competitive bidding based price discovery for 1 GW of wind projects, which would be connected to the inter-state transmission grid. However, the last date for submissions of bids was extended by three weeks to 8th January, 2017, given the high number of clarifications sought by developers at the pre-bid meeting in November, 2016 (Chandrasekaran, 2016).

Two potential reasons, namely the nature of the wind resource and the lack of public availability of reliable investment grade wind resource data make competitive bidding that much harder for wind power. Wind resource is highly location specific unlike solar resource and hence detailed knowledge of wind resource data and access to that land is a pre-requisite to bidding. Such data has historically been only collated by wind turbine manufacturers[26] and hence is not available to investors who would take part in any form of competitive bidding process. While the National Institute of Wind Energy has had a long standing wind resource assessment program, most of their wind resource data is at heights of 20/50m, which is not reliable enough for today's wind turbines with hub heights over 100m. The ministry through the NIWE should urgently commit itself to building a world class wind resource data repository, which will have wind resource data at multiple hub heights (80/100/120m), available in conjunction with other necessary information such as roads, transmission networks and land use in a GIS format. Such an initiative has a parallel in the Oil and Gas sector where the DGH is putting together a National Data Repository to consolidate and store all geoscientific data prior to operationalising the Open Acreage Licensing Policy.

A bidding framework, which takes the above issues into consideration, needs to be developed in consensus with the wind industry. However, any form of bidding will not succeed without a long term implementation plan which offers visibility and assurance of continued wind procurement, especially given the present lack of strict RPO enforcement. The bidding framework should allow for a level playing field for all players (buyers and sellers) and a transparent process of price discovery. Such a framework is certainly possible, especially given the existence of competitive bidding based wind procurement in many large markets such as the U.S., Brazil and Australia.

Both, the electricity and tariff policies have recommended competitive bidding based price discovery for renewables since 2006. The 2016 NTP amendment places further emphasis on competitive pricing, specifically to keep tariffs low. It also urges the GoI to come out with an appropriate bidding framework for this purpose (MoP, 2016). However most states are already doing reverse bidding for solar PV in spite of a lack of notified bidding guidelines from the GoI (under Section 63 of the E Act), which have been noted as the legal hurdle for bidding in the wind sector. Such legal ambiguity regarding when and where bidding based tariff discovery is to be followed is detrimental to the long term effective development of the wind

26. Some Wind IPPs have begun to set up their own wind resource monitoring programmes in the last few years.

sector. A transparent price discovery mechanism of reverse bidding, especially for mature renewable energy technologies such as wind, is urgently needed and will instil public confidence and reduce DISCOM resistance towards its purchase. Though much delayed, the MNRE has taken first steps in this direction in June 2016 by announcing a scheme along with their draft bidding guidelines for 1000 MW of wind power projects for which price will be discovered through competitive bidding. However, there is still the need for broader bidding guidelines which should be applicable for any state willing to do its own competitive bidding based price discovery for wind, as is mandated by the NTP.

4.5.3 Open Access (OA) based on renewables

While the E Act through Section 42(2) allows for non-discriminatory distribution Open Access, it has been unable to take off mainly due to the resistance from DISCOMs. The primary reason is the likely adverse impacts on the State DISCOM's already poor financial health due to loss of premium paying consumers (industrial and commercial). This in turn diminishes their ability to continue to provide the needed cross-subsidy for consumers with low tariffs. There are two additional reasons why DISCOMs are even more averse to Open Access based on renewables:

- **OA charges for RE:** To promote renewables, several ERCs have waived off or significantly reduced their open access charges (Cross-Subsidy Surcharge (CSS), wheeling and transmission charges, etc.). Table 4.4 captures these incentives for some major states. The E Act amendment Bill tabled in the Lok Sabha in November 2014 proposes to take this even further by completely doing away with CSS for all RE based Open Access. Additionally, in line with the NTP recommendation, inter-state transmission charges and losses have been fully waived by CERC for solar projects commissioned until June, 2017 and for wind projects commissioned until March, 2019. However this is only applicable to projects selected through competitive bidding. Hence, from the utility's point of view, such transactions leave them financially worse off than OA based on conventional power.
- **Responsibility of grid integration, balancing and energy banking:** Considering the seasonal or diurnal nature of the RE resource, most states provide energy banking for RE based OA and captive projects, without which such transactions are not financially practical. This incentive coupled with the lack of systems in place (as yet) for forecasting, scheduling and commercial settlement for deviations lay all the burden of system operation and balancing on the host utility adding to its resistance (TANGEDCO, 2012).

Table 4.4: Concessional OA charges and banking framework for RE in few states

States	Tamil Nadu	Maharashtra	Rajasthan	Gujarat	Karnataka	Andhra Pradesh	Madhya Pradesh
State Transmission & Distribution (Wheeling)	30% (solar), 40% (wind)	No concession	No concession	No concession[@], 50% for non-REC CPP	Transmission: 0% (solar OA/CPP)[*] Wheeling: 5% in kind (wind)	0% (CPP and OA)	Transmission: No concession Wheeling: 2% in kind
Cross Subsidy Surcharge (CSS)	50%	25%	0%	0% (solar) 50% (wind) no concession (REC)	0% (solar)	0% (solar)[&]	0%
Banking Charge (% of input energy)	12% (wind)	2%	2% (CPP)	No charge	2% (wind), 0% (solar)	2% of energy drawal	2%
Banking Period	1 year	1 year (no credit in April, May, Oct & Nov)	1 month (only for CPP)	1 month (only for CPP)	1 year (non-REC), 1 month (REC)	1 year (no drawal in Apr–June, Feb–March)[+]	1 year (drawal between July-Oct, 23:00 -24:00 & 00:00 - 17:00; Nov - Feb)
DISCOM buy back quantum beyond banking	All excess	All excess (upto 10% of yearly generation)	10% of excess energy	All excess	-	All excess from April to Jan[^]	All excess
DISCOM buy back rate	75% of wind/solar tariff; 75% of APPC[#] (i.e. ₹ 3.38/kWh REC)	APPC (i.e ₹ 3.75/ kWh)	60% of large industrial tariff	85% of wind tariff; APPC (i.e ₹ 3.76/kWh REC); 85% of APPC (solar REC)	APPC (i.e ₹ 3.11/ kWh) for captive REC 85% of RE tariff for non-REC projects	50% of pooled cost of power purchase (i.e ₹ 3.28/ kWh)	₹ 2.5/kWh (wind)[$]

Source: Various state regulatory orders & regulations, MNRE, (PWC, 2015).

@ Additional wheeling charge of 5p/kWh if wind power is wheeled to more than one location
* Incentive for 10 years for plants commissioned (2013-2018), normal charges for captive REC projects
& For 5 year period after commissioning of projects
+ Also in peak hours
^ Energy banked in February and March will be carried forward to the April of the next Financial Year
# APPC - Average Power Purchase Cost
$ For inadvertent flow into system

While there is a great deal of political and policy-regulatory support for increasing the use of renewables, it needs to be balanced with the reality of the DISCOMs financial health as well as the continued need for providing cross-subsidy to certain consumer classes. Hence, there is need for a comprehensive study on the impacts of such concessions/waivers and banking arrangements for renewables on the DISCOMs financial health. The challenge is to find innovative ways to promote renewables through open access without further financially burdening the utility. Some of the practical challenges in RE based open access are highlighted with the case of wind OA in MSEDCL[27] as shown in Box 4.3.

Box 4.3: Developments in wind power based Open Access in MSEDCL

Some wind power generators petitioned MERC (Case 19 of 2011) to direct MSEDCL to grant them non-discriminatory OA citing delay in processing OA applications, giving credit for energy supplied and commercial settlement of banked energy. MSEDCL complied with the first two requests and the commission reiterated the need to continue energy banking (MERC, 2013a). In parallel, MSEDCL issued commercial circular No. 147 in September 2011, outlining application procedure and charges for RE based OA. Upon petition by the Indian Wind Power Association (IWPA) claiming that certain clauses were not in accordance with the E Act, MSEDCL withdrew the circular. Subsequently, in January 2012, MSEDCL issued a new revised circular No. 155. The IWPA again petitioned MERC to direct MSEDCL to withdraw this circular to the extent of the objections raised in the petition. In this regard, MERC directed MSEDCL to modify its circular 155 on most issues including reiterating Universal Service Obligation (USO) obligation of utility for consumers with partial OA, continuation of energy banking, reduction in contract demand only in accordance of existing regulations, and consumers having the option of terminating/reducing contracted demand and continuation with the practice of issuing credit notes without delay (MERC, 2013b). It also directed MSEDCL to present a detailed study on the financial implications of energy banking based on actual data. In response, MSEDCL challenged the MERC ruling in the APTEL on the issues of energy banking and contract demand (Appeal 59 of 2013, 116 of 2013), but the APTEL upheld MERC's decision to allow energy banking and clearly noted

27. Wind OA has been growing in the state from 373 MUs in 2010–11 to 1055 MUs in 2013–14.

that, "only the open access consumer has the option to reduce or terminate its contract demand" (ATE, 2014).

In spite of the APTEL ruling, MERC revised its distribution OA regulations in 2014, allowing MSEDCL to reduce contract demand after consideration of CUF, and discontinued energy banking. These regulations were subsequently challenged in the Bombay High Court by the Wind Power Associations. However, in March 2016, the above regulations were amended allowing 'energy banking' as well as granting the consumer a choice of contract demand reduction in accordance with the Electricity Supply Code and Standards of Performance (MERC, 2016).

In essence, given the direct financial implications of RE based open access, MSEDCL has not facilitated OA transactions in letter and spirit in spite of several orders and directions from MERC/APTEL. This has led to lengthy and protracted regulatory and legal processes.

4.5.4 Renewable Energy Certificate (REC) mechanism

While obligated entities in each state have mandatory RPOs, renewable energy resource availability varies widely from state to state. Poor resource availability coupled with transmission constraints make it inherently difficult for obligated entities in some states to meet their RPO targets. On the other hand, few states have achieved their RPO targets and are now unwilling to procure more renewable electricity. Hence a new regulatory instrument, namely the Renewable Energy Certificate Mechanism (REC), was established in 2010 by the CERC. By allowing the environmental attribute (represented by the RE Certificate) to be separated from the electricity and traded separately, it attempted to address the mismatch between RE resource availability and RPO compliance. It also aimed at promoting additional investments and setting up alternative cost recovery business models.

Two categories of RECs, solar and non-solar (which include wind, biomass, bagasse, and small hydro power) were instituted with each REC having a denomination of 1 MWh. These RE certificates are traded over the power exchanges between the sellers (generators) and the buyers (obligated entities) and act as a valid instrument of RPO compliance. The RECs are compensated at a market determined price within a price band (a floor and forbearance price[28]) determined by the CERC

28. This price band was set at ₹ 1,500-3,900/non-solar REC from the beginning of the mechanism to March 2012. From April 2012 to March 2017, it has been revised at ₹ 1,500–3,500/non-solar REC.

which ensures sufficient compensation to the generator. The RE electricity (without the environmental attribute, i.e. REC) is treated the same way as conventional electricity, and the generator is assumed to be compensated at the pooled cost of power purchase of the buying utility (essentially its weighted average power purchase cost from all sources except those based on renewables).

A look back at the REC trades from the last five and a half years shows that there are a significantly high number of unsold RECs remaining, and trade has taken place at floor prices for the last four and a half years. This market mechanism has failed to live up to its intended objectives. While one obvious reason for the failure of the mechanism was weak RPO compliance from most states, resulting in weak REC demand, three other design shortcomings enumerated below have also equally contributed to its downfall.

- **Allowing OA/CPP projects under REC:** The methodology for determining the REC price band (floor and forbearance) assumes the sale price of power (without REC) to be at the Average Power Purchase Cost (APPC). The national average APPC for 2014–15 was ~ ₹ 3.4/kWh (CERC, 2015). While this is appropriate for REC projects selling power to DISCOMs, OA and CPP transactions have also been allowed under the REC mechanism. In stark contrast, the avoided cost of power for OA/CPP projects could be as high as ₹ 7-10/kWh (i.e. ~2-3 times higher than the assumed APPC). Hence there is an abundant possibility of windfall profits for such transactions. As was expected, 65% of the total capacity of 4,897 MW registered under this mechanism by July 2014 is contracted under these two routes (CERC, 2014). Allowing OA and CPP projects under the REC mechanism also goes against the spirit of the NTP, which notes that "through such a mechanism, the RE based generation companies can sell electricity to the local distribution licensee at rates of conventional power and recover the balance cost by selling certificates…" The Honourable High Court of Karnataka (via order dated 2nd April 2014) upheld the KERC regulations which had disallowed OA projects under the REC mechanism in Karnataka. It observed that "the RE generator who chooses to sell his power in open access to consumers in preference to power purchase agreement makes a fair amount of profit". Taking due cognizance of this issue, the CERC, as part of the 4th amendment to its principal regulations, has finally disallowed OA projects that claim "any benefit in the form of concessional/ promotional transmission or wheeling charges or banking facility benefit"

(CERC, 2016)[29]. It also disallows captive plants based on renewables and renewable energy plants having self-consumption but which do not fulfil the conditions of captive plants as prescribed in the Electricity Rules, 2005. It makes an exception for plants commissioned from 29th September 2010 to 31st March 2016. This is a step in the right direction, although much delayed[30].

- **Allowing old projects under the REC mechanism:** 1,489 MW of projects under the REC mechanism were commissioned prior to the mechanism coming into force. Such old projects add roughly 75.3 lakh RECs each year (roughly 30%) to the total REC supply (CERC, 2014). While this helped increase the market liquidity to begin with, it also additionally compensates the project owners who had set up their plants prior to the REC mechanism with separate considerations. Such projects may have also received other incentives in the then prevailing policy-regulatory framework. One of the reasons for justifying preferential tariffs for RE (paid for by the consumers in the sale to utility model) was that the benefit of significantly lower prices (once debt is repaid) would be passed on to consumers[31]. Allowing such old projects to participate in the REC mechanism unreasonably creates windfall gain opportunities for the generator without any new investments in the sector, which was one of the aims of the mechanism. RE generation assets created based on certainty of regulated revenue through preferential tariffs should be used in the interest of consumers and not for additional profit maximisation. During the third amendment process, the ERC noted that "it is true that the market has been flooded with RECs issued to these projects which in turn has dampened climate for new investment in the market." (CERC, 2014)
- **Mismatch in solar REC trading prices:** Given the price differential between solar and non-solar electricity in 2010, separate categories of RECs were institutionalised from the beginning. While the trading band for the first year up to March 2012 was between ₹ 12,000–17,000 per solar REC, it was revised to ₹ 9,800–13,400 from April 2012 and fixed for a period of five years up to March 2017. However, the price of solar PV has come down drastically in the

29. The draft version of the fourth amendment had also included the benefit of concessional cross-subsidy surcharge as a reason for disallowing OA projects under REC, but this has been dropped from the final notified amendment (CERC, 2015e).

30. The CERC had previously proposed (during the third amendment to its principal regulations) to credit only half a certificate for one MWh of electricity generated from RE with respect to OA and Captive Generating Plant (CGP) transactions to correct this anomaly. However the commission did not go ahead with these amendments and had kept them in abeyance.

31. This was especially true for states like Maharashtra with shorter PPA periods of 13 years for wind.

intervening period, where the discovered price of solar PV power through reverse bidding including its green attribute was lower than even the floor price of the REC. This coupled with the laxity in RPO enforcement completely undermined the solar REC market. Taking cognisance of these developments, the CERC has revised the solar REC trading price band to ₹ 3,500–5,800 starting January 2015 to correct this anomaly. It has also provided for vintage multipliers for older solar projects under the scheme. This is a welcome step. However, solar PV prices have continued their downfall, and latest price bids for large scale solar PV projects are already below ₹ 5/kWh (electricity + green attribute). The CERC's own solar PV tariffs are also set at ₹ 5.09-5.68/kWh (with and without AD benefit in 2016–17). This will require the CERC to further significantly revise solar floor prices downward.

These three reasons have strongly contributed to an REC supply glut and in the process undermined the very mechanism itself. While some corrective actions have been taken by the CERC, ideally they should have been operationalised much earlier. Additionally, since all generators under the REC mechanism can only sell RECs through the power exchanges, they are unable to securitise their RECs to raise funds for new projects leading to limited debt support for REC projects. Finally, with solar PV prices crashing, the earlier price difference between solar and say wind/biomass has vanished. The problem will only get more pronounced with time. Hence the very basis for differentiating between solar and non-solar RECs is debatable and will need to be addressed soon. All these factors have stifled new investments under the REC route, which is one of the primary aims of the mechanism. The commission should ideally come out with a comprehensive white paper on the need for REC, and the possible fundamental design changes needed (for example, gradually doing away with the floor price, not having different solar and non-solar segments, etc.) to keep the framework relevant and effective. A new REC framework should be in place by April 2017, till which time the existing REC price bands have been specified by the CERC. It goes without saying that strict RPO compliance is a pre-requisite for even a reformed REC mechanism to work.

4.5.5 RE transmission planning and non-uniform inter-connection practices

The activity of transmission planning is carried out in accordance with the provisions of the E Act, NEP, NTP, ERC regulations, and considering the prevalent market structure of the electricity industry. It has been hitherto aligned with conventional generation requirements. The Central Electricity Authority (CEA) has been vested with the function to formulate a National Electricity Plan, of which the National

Transmission Plan forms a crucial component. State level transmission plans are formulated by State Transmission Utilities (STUs) in accordance with provisions of the State Grid Code. The CEA has developed a Transmission Planning Manual (2013) and provided for special conditions for transmission planning criteria, relevant for evacuation of wind/solar power projects. However, the state planning code and practices by STUs in many states are still not aligned with the CEA transmission planning manual. Thus, the expansion of transmission infrastructure at the state level rarely takes into account the need for renewable energy evacuation requirements. Unless the process for planning transmission capacity incorporates a long-term vision of planned RE capacity addition and involves RE stakeholders at the planning stage, it is expected that bottlenecks in RE evacuation capacity will remain. There has been some progress on awards for intra-state transmission projects under the Green Energy Corridor in mid-2016 (CEA, 2016a).

One of the major barriers encountered by RE generators and developers is the non-uniform approach and diverse set of practices followed by DISCOMs across states for interconnection of RE projects. Numerous differences exist with regard to interconnections, such as the definition of an interconnection point, applicable charges for interconnection, permissions and clearances, and the contractual framework for an interconnection agreement. In addition, practices vary depending upon the type of renewable energy project (e.g., wind or solar), and this often results in significant delays in implementation. There is an urgent need to devise a standard methodology and protocols for interconnection processes that will be followed uniformly across states.

4.5.6 Forecasting, scheduling and commercial settlement of deviations

Maintaining constant frequency is important for the reliable and secure operation of the grid. Deviation in frequency can occur due to instantaneous differences between generation and demand, which grid operators apprehend would increase with rising penetration of variable renewables like wind and solar. Hence the critical question facing the sector is that of reliable grid integration of renewables. There are two institutions that oversee the technical standards related to grid connected renewables in India. These are, (a) CEA, which notifies regulations about grid interconnections,[32] metering, safety, transmission planning, and (b) ERCs which regulate the national and state grid codes and other supporting regulations which

32. In November 2013, the CEA amended its Technical Standards for Connectivity to the grid, wherein it specified new quality standards for power being injected into the grid as well as some ancillary services to be performed by wind and solar generators.

oversee the grid operation and management. Up to 2010, when the penetration of wind and solar power was small, grid integration was not seen as a serious issue. Hence RE was exempt from forecasting and scheduling requirements as well as supporting grid management in terms of ancillary services. However with increasing thrust to develop renewables, several attempts at technical reforms to ease grid integration have been made since 2010. These are briefly described below.

- In April 2010, the CERC notified the Indian Electricity Grid Code (IEGC) which mandated forecasting and scheduling of wind and solar power to start from 1st January 2011 (CERC, 2010a). The complementary commercial mechanism held wind generators responsible for scheduling their generation up to an accuracy of 70%. If the actual generation was beyond +/- 30% of the schedule, the wind generator would have to bear the Unscheduled Interchange (UI) charges[33], while the host state would bear the UI charges within +/- 30%. However, such UI charges borne by the host state would be proportionately shared among all the states through the Renewable Regulatory Fund (RRF). Solar generators were also mandated to give schedules but were exempt from paying any penalties for deviation from schedule. In January 2011, owing to various valid implementation difficulties, the CERC postponed the effective date to January 2012. The slow pace of implementation coupled with a lack of effective data sharing by State Load Dispatch Centre (SLDCs) with the National Load Dispatch Centre (NLDC) led the CERC to opine that "the SLDCs and the wind and solar energy generators are not taking suitable and adequate steps required for implementation of the RRF mechanism" (CERC, 2011).
- Thereafter, to resolve issues related to the implementation of the RRF, the MNRE constituted a task force headed by the Power System Operation Corporation (POSOCO) which submitted its report in July 2012. The report highlighted various implementation issues, key amongst which were the need for an alternate mechanism for imbalance settlement[34] as well as for minimising volatility in revenues for wind and solar generators. It recommended both, centralised forecasting at the LDC for grid security and decentralised forecast for imbalance settlement. Considering these recommendations, the CERC set the date for the mechanism to commence in July 2013 (CERC, 2013; CERC, 2014a). However these regulations were challenged by the wind power associations over the issue of CERC jurisdiction to implement such rules for

33. Penal charges for deviation from schedule generation/drawal.

34. The commercial settlement for the deviation of actual generation/drawal from scheduled generation/drawal.

intra-state networks. In January 2014, the CERC notified the 2nd amendment to the IEGC which effectively put in abeyance the RRF commercial settlement mechanism (CERC, 2014a).

- Finally, kickstarting this much delayed process once more, the CERC circulated a fresh draft discussion paper on 'Framework for forecasting, scheduling and imbalance handling for RE generating stations based on wind and solar at inter-state level' in March 2015. Regulations in the form of CERC (Deviation Settlement Mechanism and related matters) (Second Amendment) Regulations, 2015 (CERC, 2015a) and (Indian Electricity Grid Code) (Third Amendment) Regulations, 2015 (CERC, 2015b) were amended based on this paper in August 2015, and the new mechanism came into effect from November 2015. The new framework is quite different from the older RRF mechanism. Some of the salient features are as follows:

  a) Scheduling is applicable for all wind and solar generators (with capacity >50 MW) connected only to the inter-state grid.

  b) Forecast error is calculated as a proportion of plant availability and not linked to name-plate capacity like in the RRF mechanism. Penalties are applicable beyond a +/- 15% error and would be graded in nature from 15–25%, 25–35% and >35% error bands.

  c) Penal charges for deviation from schedule are no longer linked to the frequency (UI mechanism) but are linked to PPA rates.

  d) A centralised forecast by the LDC for grid security as well as decentralised forecast by generators for deviation settlement purposes is to be carried out.

  e) RPO compliance would be based on schedule energy with REC settlement carried out by the nodal agency, the NLDC on a monthly basis to account for deviations from schedule.

This time around, there appears to be greater consensus among all stakeholders to try and make this much needed forecasting-scheduling framework work in practice. Extending a similar framework to intra-state wind and solar generators is the next logical step. Odisha is the first state to follow the CERC example and has come out with its own draft Deviation Settlement Mechanism Regulations (OERC, 2015). The Forum of Regulators (FoR) has subsequently issued model regulations on this issue (Forum of Regulators, 2015). Seven states (Madhya Pradesh, Karnataka, Rajasthan, Tamil Nadu, Jharkhand, Andhra Pradesh and Chattisgarh) have come out with

draft regulations based on the model FoR regulations. The SERCs, especially in the remaining RE rich states (Maharashtra, Gujarat, Telangana, etc.) need to build on these model regulations and introduce forecasting and scheduling regulations for effective RE grid integration in their states.

In addition, several initiatives to address some existing weak links in the Indian grid (continued load shedding, variation in frequency, lack of adequate reserves, low flexible generation and lack of demand forecasting, etc.) are currently underway. Some of these initiatives include, a) operationalising regional reserves across the country, b) start of frequency regulation under the ambit of ancillary services (CERC, 2015c), c) pilots on Automatic Governor Control (AGC) for secondary frequency control, d) more states moving towards the intra-state Availability Based Tariff (ABT) mechanism, e) 24 X 7 intra-day power markets (CERC, 2015d), f) operationalising technical minimum (55%) operation of Inter State Generating Stations (ISGS)/Inter-state coal plants (CERC, 2016a), g) revision in area control error from 150 MW to 200–250 MW for 'renewable rich states' (CERC, 2016b) etc. Effective demand forecasting by DISCOMs, which has been identified as the primary reason for large deviations and regulation of ramp rates for power plants, is expected to be operationalised in the near future. These will go a long way in reducing many of the existing problems in the Indian grid. More importantly, all these measures are needed for effective, reliable and secure operation of the grid, irrespective of whether the grid has a high penetration of variable renewables like wind and solar or not. However these will also help ease the integration of renewables into the grid. For effective RE integration, apart from RE specific initiatives like forecasting and scheduling, it is equally important how the rest of the system evolves.

4.5.7 Social and local environmental implications

At present, RE projects are exempted from Environmental Impact Assessments (EIA) or Social Impact Assessments (SIA), making it difficult to gauge whether there are any particular local adverse impacts from these projects. In 2016, the MoEFCC has recategorised industries based on their pollution load as determined by a pollution index made up of among other things, emissions, effluents, hazardous wastes, consumption of resources, etc. Under this new scheme, industries with very low pollution indices (white industries) such as wind power and solar PV power have been exempted from the environmental clearance as well as consent to operate requirement from the State Pollution Control Board (Aggarwal, 2016). However one distinction that this new categorisation fails to make is the difference

in potential impacts during project construction and impacts during project operation.

While RE projects certainly outperform conventional power plants in most environmental indices, they can still have some local impacts (as seen in the literature) though they tend to be significantly lower than any conventional power plants. Two of the important issues that repeatedly come up are:

- **Adverse impact on the surrounding natural environment and livelihoods:** Some wind projects during their construction phase (such as while making approach roads and site clearing) have impacted ecologically sensitive regions (Byatnal, 2012). One example is of a wind project located in the plateaus on the Western Ghats — a global hotspot of biological diversity[35]. Another related issue is the potential impact of wind turbines on birds. In 2016, the Rajasthan government has decided to not allow wind power projects in areas where the state bird, the Great Indian Bustard, is found (IANS, 2016).

- **Irregularities in land transactions and compensation:** Wind and solar power are land intensive power generation technologies. Over the years, there have been a few news reports of irregularities in such private land transactions and compensation paid thereof. For example, a Government of Maharashtra inquiry committee report tabled in the legislative council details various types of irregularities and violations concerning land transactions for wind power projects in the state (Gangan, 2015).

It is clear that the existing policy-regulatory framework has not given adequate consideration to such social and local environmental issues. Inclusive RE development by addressing such issues is crucial to achieve sustainable and long-term desired growth in the sector, as local protests may otherwise stall the progress of RE in the country. Some desirable policy changes are listed below:

- A renewable energy specific land use policy that encourages long-term land leasing (on a footprint basis for wind power to the extent possible) with fair royalties as compensation to the land owners coupled with transparency in land

35. Additionally, the lack of information over reserved and ecologically sensitive areas has at times resulted in parts of the wind farm encroaching into those lands. As witnessed in a wind farm near Satara, Maharashtra, 215 out of the 1,240 windmills have been constructed inside the Koyna sanctuary area. Here the sanctuary was not notified despite being declared many years ago, which created confusion over the demarcation of the actual sanctuary area. The Maharashtra Government imposed a fine of ₹ 35 crore for installing such structures in the tiger reserve.

transactions. A proposal on these lines is being worked out for solar projects by the MNRE, wherein land owners and even panchayats would be made project stakeholders and will earn a regular income (Dutta, 2015; HBL Bureau, 2015).

- A process for informed local consent in letter and spirit through institutionalising EIAs and SIAs to be carried out with the active involvement of the community that could point out the imminent adverse impacts if any and means to prevent or minimise them.
- A formal institutional structure for revenue/benefit sharing with the community to replace existing ad-hoc processes. An example of such local benefits sharing is instituted by Maharashtra (See Box 4.4).

Box 4.4: Wind power projects benefit sharing in Maharashtra

Wind power projects need to pay some local taxes in Maharashtra. According to the notification by the state government in 2011 (GoM, 2011), the village panchayat tax is charged based on the area occupied by the project which is further divided into a) tax on basement area of the tower, and b) tax on open space between the towers. Details are provided in Table 4.5. The maximum amount of tax to be charged per windmill tower is ₹ 15,000 per MW. This is a welcome first step by the state government. Nevertheless, it implies that an independent agency should monitor that the revenue thus earned by the panchayat is utilised for community welfare.

Table 4.5: Gram Panchayat tax provision for windmills in Maharashtra

Part of towers	Type of Gram Panchayat	Area	Minimum rate (₹)	Maximum rate (₹)
Basement of tower	Any	per sq. ft.	3	8
Open spaces between towers	General or hilly adivasi area gram panchayats	per 100 sq. ft.	0.2	0.4
	All gram panchayats abutting municipal corporations or municipalities	per 100 sq. ft.	0.4	0.8

4.5.8 Weak data management

Poor data management and lack of availability of comprehensive up to date data in the public domain remain weak links in the renewable energy sector. This has serious implications for planning, target setting and mid-course corrections. Lack of a central repository of RE projects and associated performance and cost data makes it very difficult for regulators to set accurate tariffs and monitor compliance. While serious efforts are underway in making revised and detailed wind and solar resource maps for the country (NIWE, 2015b), overlaying this geographically mapped resource data with other useful information on land use, water availability, transmissions lines, roads etc. through a GIS interface would assist policy makers in more realistic and integrated energy planning while potentially minimising conflicts and delays (Sreenivas & Dixit, 2015). Additionally there is a need for stronger and more effective integration of MNRE and CEA processes for collection and dissemination of RE data. The CEA needs to consider renewables an integral part of the electricity sector and begin including RE data (including but not limited to capacity, generation, ownership, technology, size, prices, etc.) in all their publications. Finally, data on decentralised RE systems such as grid connected rooftop solar PV systems should also be included to the extent possible.

4.6 Legal and policy reforms on the anvil

While we have analysed several important policy and regulatory reforms of the past in the previous sections, several more reforms are in the pipeline, likely to come into force soon. Some of the important ones are discussed below.

4.6.1 Draft Renewable Energy Act and proposed amendment to Electricity Act, 2003

The MNRE has initiated a process for framing a Renewable Energy law to address some RE specific issues and give further impetus to renewable energy development. A draft has been put up for public consultation (MNRE, 2015b).

In parallel, a bill was introduced in the Lok Sabha in November 2014 to amend the Electricity Act, 2003 (MoP, 2014). It proposes several new ways to strengthen the growth of RE. Most importantly it completely waives off the Cross-Subsidy Surcharge (CSS) for renewable energy based open access transactions. This is a significant incentive for RE development, but it needs to be balanced with the existing precarious financial health of the DISCOMs which would lose out vital cross-subsidy resources to ensure affordable tariffs for agriculture consumers.

A new concept of 'Renewable Generation Obligation' (RGO) mandating new thermal generators to establish or procure a certain minimum RE capacity has also been mooted. However, this would be effective only if RPO compliance is strictly adhered to, for which a more stringent penalty has been suggested. However, this is a fixed penalty of ₹ 1 crore for each contravention and is not linked to the extent of non-compliance and hence may not sufficiently deter non-compliance. Instead, a penalty based on average cost of renewable generation applied on the total quantum of non-complied obligation could be a better mechanism to meet the intended objective.

Finally, it also recommends waiver of the license requirement for a person who intends to generate and supply electricity from RE sources. However it is unclear what this entity would be in a legal and regulatory sense if it is not a supply licensee, which in turn may create metering and billing issues and may result in ambiguities regarding such operational obligations and functions/duties. Since the aim is to promote RE based generation, this can be achieved by treating all consumers who source power from RE sources as deemed open access consumers (irrespective of contracted demand). Such a provision should be certainly considered, as along with promoting renewables it will also ensure that the entities undertaking supply functions are held responsible for their due functions and obligations. Such a provision will also be useful for small scale decentralised distributed generation based on rooftop solar PV plants which could be owned and operated by a third party (PEG, 2015).

4.6.2 Wind power policies

Several initiatives to support wind power development are underway. Important among these are a national wind mission, modelled on the lines of the national solar mission. In addition, a national wind policy which has several facilitating elements like creation of wind parks, central procurement of wind power, setting up a better wind resource monitoring programme, and building consensus and supporting grid integration is in draft stage (MNRE, 2015c). However, it is completely silent on the very important issue of pricing and in that sense, it would be a missed opportunity to move the sector in the direction of competitive price discovery. In 2015, the MNRE released the National Offshore Wind Energy Policy which aims to promote offshore wind development through a competitive bidding framework based on leasing of offshore blocks (MNRE, 2015d). The MNRE has also come out with a policy for repowering of wind power projects and a draft policy on wind-solar hybrids. It has also put out draft guidelines for development of onshore wind

power projects to further facilitate the development of the sector (MNRE, 2016i; MNRE, 2016j; MNRE, 2016k).

4.6.3 Goods and Services Tax (GST)

In August 2016, the GoI passed the Goods and Services Tax (GST) Bill which will replace the existing indirect tax structure. Most indirect taxes (with a few exceptions) would be subsumed under the GST. Based on existing information available in the public domain, it appears that tax on consumption or sale of electricity would be outside the ambit of the GST, but taxes on various capital goods, inputs and input services used for RE would be covered by the GST. This could have very adverse implications for RE (unless exemptions continue or RE is placed in the nil bracket for GST taxes), with one report estimating an increase in levelised tariffs for solar PV and wind power to be in the range of 11–16% (MNRE, 2016l).

4.7 Conclusion and lessons

While the renewable energy sector has seen impressive growth in the last few years, new challenges continue to emerge (as outlined in Section 4.5), which if not addressed comprehensively may slow down RE growth or may result in a sub-optimal development of the sector. Some of the important learnings for future policy-regulatory processes emerging from the experience of the last few years are captured here.

4.7.1 Need for holistic integration of renewable energy within overall electricity sector planning and operation

Renewable energy capacity, currently at 46 GW (October, 2016) is targeted to reach 175 GW by 2022. According to CEA's draft national electricity plan (generation), RE may contribute 33% and 43% of total generation capacity[36] in 2022 and 2027 respectively. Similarly, the share of RE in total electricity demand[37] is set to rise to 20.3% and 24.2% by 2022 and 2027 respectively (CEA, 2016b). Given that it will form the most significant share of the incremental capacity addition up to 2022, the days of treating it as 'add-on' or 'marginal' are over. As is already becoming evident, the RE sector will have to confront issues faced by the entire electricity sector. It is unclear whether this ambitious target has been developed taking a critical and in depth cognisance of various issues. For example, low gestation periods

36. Total generating capacity is expected to be 523 GW and 640 GW in 2022 and 2027 respectively.

37. Total electricity demand is expected to be 1,611 BU and 2,132 BU in 2022 and 2027 respectively.

(1–1.5 years) and variable nature of RE generation add to the complexity of grid planning and operation. Large RE targets coupled with higher upfront costs could potentially result in high retail tariff impacts for consumers. Similarly, DISCOMs are already in deep financial trouble and regulators have neither been strictly enforcing RPOs nor increasing them as expected.

Ideally a national RE target should have evolved through multiple considerations such as (a) expected RE cost trajectories and resulting tariff impacts across states, (b) available fossil fuel resources, imports, their prices and impact on Current Account Deficit and energy security, (c) the industrial policy of the country, (d) roles of different departments and agencies, (e) impact of incentives such as energy banking, concessional/waived open access charges and loss of sales from rooftop solar on the DISCOMs financial health in the short term and on the fundamental viability of its current business model in the long run, and (f) local social and environmental impacts of energy use. While significant emphasis has been laid on supply side interventions to increase RE deployment in the past, it might be prudent to shift focus to demand side measures to create serious demand pull from mandatory and voluntary procurers of RE capacity going forward. In short, planning for the RE sector needs to be more comprehensive and consultative, and should take states and DISCOMs on board and address their concerns given the differing priorities and capabilities of the centre and states on some issues.

4.7.2 Need for a broad long-term vision, yet nimble policy-regulatory RE framework

Renewable energy is a dynamic and a fast changing sector wherein early feedback on any issue is important to be appropriately incorporated into policy-regulatory reform. However, one sees several examples of delay in internalising various early warnings.

a. While any sector needs incentives in the early phase of its development, they should ideally be introduced with some form of sunset clause. This gives all stakeholders certainty and the signal to eventually move towards full cost recovery principles and finally leads to stronger growth on its own economic fundamentals rather than being limited by (at times) uncertain state support. The flip-flop around incentives such as Accelerated Depreciation and Generation Based Incentive in the wind sector and continuing support for capacity-based incentives (at least till 2017) show that there is uncertainty in

this regard, trapping the wind sector in a low-growth cycle based on short-term considerations.

b. With solar prices discovered through competitive bidding being lower than wind feed-in-tariffs in various states, it may not be prudent for policy makers to continue the distinction between solar and non-solar Renewable Purchase Obligation targets. Obligated entities should be able to procure the cheapest form of renewables, subject to technical grid constraints.

c. In spite of regular monitoring, the Renewable Energy Certificate mechanism has been slow to respond to various changes in the RE sector. The proposal to check the windfall gains by Open Access/Captive projects has only been notified in 2016 after some delay (CERC, 2016). There is still a much needed correction in solar REC price bands. With the prices of solar and wind power converging, the REC mechanism will soon need to be fundamentally reformed to end the solar/non-solar differentiation.

d. DISCOMs and Load Dispatch Centres have been wary of variable generation sources like wind and solar and have faced some difficulties in grid operation/management on this account. However while forecasting, scheduling and deviation settlement frameworks have been in discussion since 2010, a mechanism for projects connected to the inter-state grid has only become operational in November 2015. A suitable framework is urgently needed to be adopted by states for projects connected to the intra-state grids. Capacity building and institutional strengthening of state entities — Load Dispatch Centres/Transmission Utilities/Nodal Agencies — are necessary and equally important for the effective implementation of such a mechanism.

e. Development of some RE projects across the country have resulted in some form of local environmental degradation and social strife over land use/compensation, in spite of which EIA, Environmental Management Plan (EMP) and SIA are not yet mandated as part of policy.

These examples indicate that policy makers and regulators will have to be more proactive and open to quicker changes in policy-regulation to prevent uneven development which is detrimental to the sector's long term future. An effective ongoing review and correction mechanism can help the policy-regulatory framework be more agile to proactively respond to the dynamic nature of the sector.

4.7.3 Weak implementation of Renewable Purchase Obligation and Open Access regulations

Weak RPO compliance by most DISCOMs and other obligated entities (OA and captive) in spite of the existence of the REC mechanism is a classic example of lax implementation of regulations including the levy of penalties. The target of 175 GW cannot be achieved if RPOs are not complied with. Thus, effective monitoring and verification mechanisms and public availability of information is critical to ensure that policy goals are met. Similarly, most states have not implemented open access regulations in the spirit of the E Act thereby slowing down the growth of renewables.

4.7.4 Cost reduction through effective competition and government facilitation

Facilitating actions from governments are critical to make genuine competition work. The proactive initiatives (such as reverse competitive bidding, solar parks, bundling with thermal power, central PSU as intermediary for procurement, payment risk guarantee fund, etc.) from the GoI under the solar mission laid the foundation for a very competitive solar sector. Solar PV is certainly a success story of reducing prices facilitated through the policy of bidding based price discovery, which was able to reap the benefits of global manufacturing at scale. However, the much older wind sector has been unable to move in this direction as yet, though multiple policies such as the NEP, NTP and NAPCC have envisaged and encouraged it. In spite of initiating the process to formulate bidding guidelines for RE under E Act, (Section 63) twice in 2010 and 2012, these are yet to be finalised and notified by the Ministry of New and Renewable Energy/Ministry of Power.

Supporting actions reduce risks and entry barriers for new entrants, improve confidence and in turn costs due to lower gestation time and possibly lower interest rates. The government can take some more facilitating actions in this spirit such as a) undertaking detailed resource assessment in the country and making high quality resource maps public to reduce the information asymmetry currently prevalent, b) effective collection and dissemination of data to make policy formulation and investment decisions more robust, and c) inclusive frameworks for land use policies for RE (such as informed consent and revenue/benefit sharing with the community) to make RE more acceptable around the country.

5

Electricity distribution: On square one, even with reforms after reforms

"The old man kept cleaning mud on his left foot with his right

And right foot with left, left with right, right with left ...

Till children came along with water

And showed him how it's done"

- Malayalam poem by Kunjunni Mash

5.1 Introduction and overview

This chapter examines reforms in electricity distribution and briefly explores transmission. Transmission system voltages are 66 kV or above, and it consists of substations and power lines strung on tall towers.[1] It carries bulk power and forms the national grid which electrically interconnects the whole country. Distribution system voltages are below 66 kV, and it consists of substations and lines stringed on poles or underground cables. It is the first interface with the consumer, has significant linkages with development, and is a major instrument of public policy. Proof of the pudding, as the saying goes, is in the eating. Measures in any other sector in electricity — be it fuel supply, generation or transmission — will be considered effective only if they result in better electricity service to consumers. Distribution is the crucial, but presently the weakest link in the electricity sector.

A well-functioning distribution sector is essential for the provision of good electricity service. Our understanding of better distribution is one where the Distribution Companies are financially healthy, accountable to the public, and are able to provide affordable, reliable electricity access to all on a sustainable basis. However, with persistent financial issues, operational challenges and programme implementation delays, Distribution Companies (DISCOMs) are far from achieving this objective.

1. This is what is common. In some locations like cities, industries etc., there can also be underground transmission cables.

In the last two decades of reforms, many changes have been introduced in the distribution sector, with a stated objective of improving the state of affairs. There was a focus on reducing inefficiencies in the sector by increasing competition and encouraging market operations. Due to this, there has been increasing private participation, a greater choice for big consumers, significant role for market forces, and the reducing role of the state. However, these efforts have not even yielded the expected result of creating a financially viable sector, let alone providing quality affordable electricity access to all.

How does one study the impacts of measures taken during reforms? One must examine if reform efforts have increased quality affordable access and improved sector health to sustain that access. This requires the sector to be efficient in technical and financial terms. Ensuring that reform changes are carried out with fairness requires that the sector governance is democratic. This in turn requires transparency in availability of information, ensuring public accountability of utilities, creation of spaces for public participation and developing capacity of civil society for informed participation. Thus it is important to look at the changes in three important factors during the reform period:

- Technical and financial efficiency of DISCOMs
- Quality of electricity access
- Democratisation of governance

This chapter examines reform efforts in the distribution sector and its impacts. This includes SEB restructuring, distribution privatisation, power purchase, initiatives to increase consumer choice, short term markets, DISCOM finances, rural electrification, the transmission sector, and regulatory institutions. The transmission sector is not covered at the same level of detail as that of distribution, but is included to introduce this crucial sector.

5.1.1 Restructuring of State Electricity Boards (SEBs)

As mentioned in Chapter 1, restructuring of State Electricity Boards (SEBs) was taken up in the mid-1990s as a response to the growing crisis in the sector. This crisis included poor financial health, power shortages and poor quality of supply. Many suggestions were made by government appointed committees to improve the situation, but the reform measures were largely pioneered by the World Bank and other international institutions, who borrowed heavily from reform attempts of the electricity sector in other countries. When the distribution reform efforts

started, the plan was to have Electricity Regulatory Commissions (ERCs) in all states, corporatise the SEB operation by breaking it into multiple companies and subsequently privatise them, starting with distribution. ERCs and corporatised Distribution Companies (state or private owned) were expected to adopt a professional approach and operate at arm's length from the government. This was expected to improve operational efficiency and lead to commercial viability of the sector.

There are 29 states and 7 union territories in India. Bigger states and the national capital Delhi had state owned Electricity Boards, whereas smaller states and union territories had Electricity Departments. The restructuring involved unbundling and corporatisation of State Electricity Boards (SEBs) and establishment of the Electricity Regulatory Commissions (ERC). This started in Odisha in 1996 with the formation of the Odisha ERC and separate companies for generation, transmission and distribution. Today all states and union territories have ERCs, and there are two Joint ERCs, shared by small states[2]. Except Arunachal Pradesh, Manipur, Mizoram, Nagaland, Sikkim, Goa, Himachal Pradesh, Kerala[3] and Jammu & Kashmir, all states have unbundled their SEBs to form separate companies (Planning Commission, 2014a). In a few states like Tamil Nadu, Bihar, Jharkhand, and Punjab, unbundling of SEBs was carried out just a few years ago.

Restructured states typically have one or more distribution companies, one state owned transmission company and one state owned generation company.[4] Some states also have private generation and distribution companies. There is variation in the number and nature of companies set up in different states. Eight states have a holding company which controls all the unbundled companies. Twelve states have only one distribution company for the whole state[5], while the rest have three or four companies, with the result that there are 40 state owned distribution companies

2. There is one joint ERC for Manipur and Mizoram, and another for Goa and Union Territories.

3. In Kerala, a company Kerala State Electricity Board Limited was registered in 2013 to handle generation, transmission and distribution.

4. Some exceptions are 1) Odisha, which has a state owned Hydro Power Corporation and Odisha Power Generation Corporation, a thermal station in which the state government has a 51% share, and a private company AES has the rest. 2) Tamil Nadu, Punjab, Himachal Pradesh and West Bengal: one company handling generation and distribution, and another for transmission. In West Bengal, the distribution company has hydropower stations as well, and there is another company for thermal generation.

5. Holding companies are present in Tamil Nadu, Maharashtra, Chhattisgarh, Assam, Meghalaya, Uttar Pradesh, Gujarat and Delhi. States with one Distribution Company are Maharashtra, Tamil Nadu, Chhattisgarh, West Bengal, Punjab, Uttarakhand, Jharkhand, Assam, Tripura and Meghalaya (Pargal & Mayer, 2014).

in the country. Additionally, there are nine private distribution companies, 10–15 urban distribution franchisees managed by private companies, and around 2 lakh rural distribution franchisees.[6] There are also a few municipality owned distribution companies (like Brihanmumbai Electric Supply & Transport Undertaking or BEST in Mumbai, New Delhi Municipal Council (NDMC) and Thrissur Corporation Electricity Department in Kerala), rural electricity supply cooperatives (in Andhra Pradesh, Telangana and Karnataka) and some areas managed by the Military Engineering Services (MES).

Unbundling of SEBs and formation of companies has not introduced professional practices. In most states, distribution companies do not meet the requirements for independent commercial operation. Boards are dominated by state government appointed directors. In many states, all the distribution companies are headed by the State Energy Secretary or the Chairperson of the Transmission Company. Even when there are multiple distribution companies, all decisions are centralised at the state level, thus defeating the very purpose of forming smaller agile organisations. Many distribution companies do not have independent directors or do not have the specified minimum percentage of independent directors, despite repeated recommendations by government appointed review committees to do so (IIPA, 2006; Planning Commission, 2011; Pargal & Mayer, 2014). Tenure of the Chief Executive of distribution companies is often shorter than the recommended three to five years. The Chief Executive is often an IAS officer, and by the time she starts understanding the sector operation in a few years, she is transferred. These companies are rarely evaluated for performance. Many of the functions of the company are outsourced and there has hardly been any major recruitment since the 1980s, with the result that there is shortage of staff and the average age is high (Planning Commission, 2011). Issues with the SERCs are covered in a subsequent section, which also show many challenges with their capacity and functioning.

Some state owned distribution companies have been able to improve performance, perhaps due to political support, better management, appropriate investment, or use of technology. DISCOMs in Andhra Pradesh, Karnataka, Gujarat and Maharashtra

6. Private companies in cities are: CESC (Kolkata), Noida Power Company, Ahmedabad Electricity Company, Surat Electricity Company, Reliance Infra – Distribution (one company in Mumbai and two in Delhi), Tata Power – Distribution (one company in Mumbai and one in Delhi). The exact number of functioning urban franchisees is not clear, and this approximate number is compiled by the authors. The number of rural franchisees is from a 2013 report on rural electrification (RGGVY) and majority are not operational. Most of these are village based, involved in revenue collection, and a few cover larger area, as in the Central Electricity Supply Utility (CESU) divisions of Odisha. Current rural electrification programme reports do not include the number of franchisees.

have improved billing, bill payment and consumer interface in cities. They have reported significant loss reduction, though these are questionable (Chitnis & Josey, 2015; Reddy, 2007; MSEDCL, 2016a; PFC, 2016a). Gujarat implemented separation of agriculture and rural feeders as early as 2006, and Maharashtra introduced a load shedding protocol to decide the mode of sharing electricity shortage through transparent public process. During the period 2006–08, Maharashtra also had pioneered 'Akshay Prakash', a utility supported, community led voluntary loss reduction programme, with significant loss reduction (Planning Commission, 2007). Many companies have in the recent past taken up massive energy efficiency programmes in lighting and agriculture and have started promoting distributed solar projects. Distribution loss has significantly reduced and quality of service improved in Delhi, where distribution was privatised in 2002.

Coming back to the main story of the two decades of distribution reforms, one could say that restructuring of SEBs is indeed procedurally complete. But it is not functionally complete and there have been mixed results in meeting the stated objectives. While government entities have been unbundled, there has been no insistence on unbundling and separation of accounts of privately owned integrated utilities which operate distribution companies in major cities. Surely, even private companies would benefit from the same efficiency gains which unbundling was supposed to usher in. One suspects that unbundling was just an intermediate step towards privatisation and therefore considered unnecessary for private utilities.

5.2 Private sector participation in distribution

Although private distribution companies existed in India before the reform efforts, privatisation as a strategy to bring in much needed efficiency and financial turnaround after unbundling was first attempted in Odisha and Delhi. Another model of privatisation was to privatise certain parts of a distribution business for a specific area through distribution franchisees. These privatisation efforts are analysed in this section.

5.2.1 Odisha: Public to private to public and to private again?

Odisha is one of the poorest states in India. It is rich in natural resources, but in the 1990s, nearly half its population was below the poverty line. There are a few special characteristics of Odisha state and, specifically, its power sector. The power sector in Odisha is relatively small with many big bulk consumers. Even though its rate of urbanisation is one of the lowest in the country, power consumption by agricultural

users is quite small — 3% of the total consumption — compared to the all-India average of 32% in the year 1995 (Planning Commission, 2002). Rural household electrification at 24% in 1991 was also one of the lowest (Census of India, 2001). There was a tariff hike amounting to 67% in the period before reforms — between 1992 and 1995. In 1995, the tariff revenue was sufficient to meet the Odisha State Electricity Board (OSEB) operational cost, indicating a financially viable sector (GoO, 2001) Finally, Odisha has relatively low levels of political mobilisation and a relatively minor national profile. All these reasons would have contributed to the coming together of the World Bank, Government of Odisha and Government of India to choose Odisha as the state to launch the SEB reforms in 1996 (Dubash, 2002).

The Odisha privatisation efforts were to start with the distribution sector and subsequently proceed to the transmission and generation sectors. In the first phase of unbundling, the OSEB was split into two generation companies (for hydro and thermal generation) and Grid Corporation of Orissa (GRIDCO) to manage transmission and distribution. The distribution business was divided into four zones – central, northern, southern and western. In 1996, a three-year management contract was awarded to BSES (the private distribution company, managing electricity distribution in suburban Mumbai) to manage the central zone of Odisha. However, this was terminated after six months, since the contract conditions were not met. In 1997, four Distribution Companies were formed (each for a zone) and a request for joint venture participation was invited in 1998. 51 companies initially participated in the international competitive bidding for privatising four companies (offering 51% stake to the private investor, 39% retained with GRIDCO and 10% with the Employees Welfare Trust), seven submitted bids and only three qualified, namely BSES, Singapore Power — Grasim consortium, and Tata Electric Company (TEC) — Viridian[7] consortium. In 1999, the BSES was selected for three companies and TEC consortium for one, namely the Central Electricity Supply Company (CESCO). After the TEC consortium refused to honour its offer, AES-Jyoti Structures consortium (henceforth called AES, and one of the pre-qualified bidders) was offered CESCO. After some negotiations, assets and management control were transferred to the private companies (IIPA, 2006) (TERI, 2015).

After a few years, it became clear that there were many problems with the privatisation process. There was no proper baseline estimation of T&D losses, loss reduction targets were unrealistic; there was no government subsidy support to

7. Viridian was the holding company of Northern Ireland Electricity of United Kingdom.

the sector; demand growth projections turned out to be over-ambitious; private companies did not bring capital or take administrative measures to reduce losses or collect arrears; and dues owed by the companies to state owned transmission company (GRIDCO) kept increasing. In 2001, the AES abandoned CESCO after not following the contract conditions or the OERC directions and the state government took over the distribution (IIPA, 2006).[8]

The other three private companies consistently failed to meet the targets for reducing losses and improving supply quality. The government appointed the Kanungo committee and the World Bank's implementation commission report candidly noted that the reform had not worked (GoO, 2001) (World Bank, 2004).[9] The situation did not improve and in 2005, the OERC proactively initiated procedure to suspend the licenses of the three private companies (managed by Reliance Infra, which had taken over BSES), and appointed special officers to monitor their performance. This order was challenged by Reliance in the ATE, which gave an order in 2006, resulting in the withdrawal of the special officers. The OERC challenged the ATE order in the Supreme Court, which gave a judgement in 2009 supporting the OERC. It upheld the action of the OERC to proceed with the suspension. The OERC passed an order in 2011 accusing the companies of poor performance, failure to run the organisation in a financially viable manner, and not following the OERC directives, but giving them time to improve.[10] The OERC also conducted performance reviews on the companies, and in 2013 issued show-cause notices to them. After clarifications and hearings, the licenses of the three companies were revoked in March 2015. The reasons given were highly unsatisfactory performance (insufficient reduction of losses, non-payment of arrears for power purchase,

8. The Kanungo Committee Report has an Annexure on the exit of the AES. It gives many details and makes a startling statement that the AES had taken up CESCO (a DISCOM) hoping that its share in the Odisha Power Generation Corporation (OPGC) (the thermal generation company) will be increased from 49 to 51%. When it did not materialise, the AES started losing interest.

9. From the Kanungo Committee Report about the role of consultants who planned the reform: "However, judging by the fate of the reform and the present state of the utilities, we feel that not only were some of the major assumptions underlying the reform scheme overambitious and unrealistic, but the utilities for whose benefit the consultants were engaged also could not assimilate much of their advice. As a result, the utilities, instead of developing inner strength with the assistance of consultants, tended to be excessively dependent on them. Specific instances of this leading to near atrophy of organisational strength came to our notice in the course of our interaction with senior officials. We suggest that this practice, which weakens organisations rather than strengthening them and de-motivates the employees instead of improving their skill and confidence, should end as soon as possible." (page 47).

10. Shri. Jairam Ramesh, then Union minister, had said in 2009: "Privatisation of power distribution in Orissa has been a complete failure and it is shocking that private companies have been allowed to get away with such dismal performance", as reported in The Statesman, 31st January 2009.

failure to follow OERC directives, etc.) and non-incorporation of clauses in the shareholder agreement, like transfer of shares to group companies without prior approval (OERC, 2015). The Order notes that the distribution loss has remained at 40% for the past several years (it was around 45% in the first year after privatisation) and the accumulated losses of the three distribution companies were ₹ 2424 crores in 2013. The order also notes that the distribution companies contributed only 11% to the total capital expenditure of ₹ 1440 crores between 2000–2013, while the majority contribution was from consumers, GRIDCO, World Bank etc. This order has been challenged in the ATE, which has refused to stay the OERC order, but has also not issued a final order in the matter as of September 2016 (ATE, 2016). As of now, the three erstwhile private distribution companies are managed by the state owned GRIDCO.

The fourth company CESCO was being managed by the government after the exit of the AES. The OERC had appointed a nominated officer of the state government to take management control of CESCO in 2001. After many hearings, which gave opportunities to the AES to represent their case, in 2005, the OERC revoked the distribution license and appointed a Chief Executive Officer to manage the distribution in the central zone, the area managed by CESCO. The OERC also tried to attract private players to take over distribution without success. Then in 2006, the OERC formulated the Central Electricity Supply Utility (CESU) of Odisha (Operation and Management) Scheme, 2006 for two years and kept extending its license. But the performance in terms of financial losses or electricity losses has not improved, and 14 of the 20 divisions of the CESU were handed over to franchisees with five year agreements, from 2012–13 onwards. In April 2016, the OERC has issued notice inviting expression of interest for purchase of the CESU (GoO, 2016).

Table 5.1 lists the major Odisha distribution reform milestones from 1996. It can be seen that Odisha reforms have come a full circle. In the initial years, there was great enthusiasm to privatise the sector. The private operation faced many challenges, including lack of transition subsidy support, ambitious loss reduction and load growth targets and the limited experience (and perhaps commitment) of private companies in managing rural distribution systems. The regulatory oversight was a big challenge with limited capacity to implement privatisation and managing high levels of litigation. The sector today remains as inefficient as it was when reforms began in 1999 and once again there are efforts to attract private players. There has been some progress in rural electrification due to central and state programmes, but that had nothing to do with the reform efforts.

Table 5.1: Major distribution reform milestones in Odisha

Milestone	Year
Reform Act, World Bank project start, formation of OERC	1996
Distribution privatisation - 1 company with AES, 3 with BSES/Reliance	1999
Exit of AES from CESCO	2001
Kanungo report	2001
Closure of World Bank project	2004
OERC initiates action to suspend licenses of 3 Reliance DISCOMs	2005
OERC forms CESU to manage CESCO	2006
OERC order on monitoring performance of Reliance DISCOMs	2009
OERC show cause notice to Reliance DISCOMs	2013
OERC revokes licenses of Reliance DISCOMs	2015
OERC invites applications to privatise CESU	2016

5.2.2 Delhi privatisation

Distribution in Delhi was managed by the Delhi Electric Supply Undertaking (DESU) till 1997. The Delhi Vidyut Board (DVB) was set up like an SEB to improve distribution, but with little results. The distribution sector in Delhi was in a very bad state by 1998, with electricity losses as high as 50%, huge financial losses (nearly ₹ 1,100 crores/year), power shortages, poor quality of supply and low credibility of the Delhi Vidyut Board (IDFC, 2010). Compared to the other SEBs, electricity distribution in Delhi is very different. Load density is high and many consumers are in a better financial position to pay. In 2001, Delhi did not have the challenges of low access or high agriculture consumption faced by most Indian states. However, there was all around dissatisfaction with the functioning of the Delhi Vidyut Board and very strong political backing to the reform process in Delhi.

In 1999, the DVB was split into seven companies – a holding company, two generation companies, a transmission company and three distribution companies. The DERC became functional in 2001 and privatisation efforts began in 2001–02. The privatisation process was handled by the Delhi government with no involvement of the DERC or foreign consultants, as was the case in Odisha. In Delhi, SBICaps was the consultant to the government. Distribution in three zones were bid out based on companies agreeing to Aggregate Technical and Commercial (AT & C) loss reduction trajectory (17% reduction in 5 years), regulation of retail and bulk

supply costs, 16% return on capital base, annual tariff hike, taking over the existing liabilities, and transition financial support for the first five years. After a qualification and bid process as well as negotiations, 51% of the shares in the three distribution companies were privatised, with Delhi government retaining 49%. Perhaps due to the high losses prevalent in the Delhi distribution system and due to the failure of distribution privatisation in Odisha, there was limited interest by private companies. Out of the six pre-qualified bidders, only two submitted final bids (BSES for three companies and Tata for two). The final agreements with these two companies were reached after further negotiations (Agarwal, Alexander, & Tenenbaum, 2003).

The privatisation effort in Delhi was quite different from that in Odisha. The Delhi government offered a five year transition support of ₹ 3,450 crores, in addition to support from central programmes, whereas in Odisha, there was no state support. Estimation and reduction targets of losses were better in Delhi, and the private companies could meet the targets. Only realisable liabilities were transferred to Delhi companies. Delhi also benefited from the availability of cheap power from central generating stations. (Agarwal, Alexander, & Tenenbaum, 2003).

One and a half decades after privatisation, distribution in Delhi presents a mixed picture, though better than that in Odisha. The AT&C loss has come down to nearly 14% (PFC, 2016b) and quality of service (in terms of distribution transformer failure, complaint handling, ease of bill payment, etc.) has improved considerably. From 2015, the AAP (Aam Aadmi Party) government has offered amnesty schemes on arrears and significant state subsidy for domestic tariff reduction. However, there have been doubts on the capability of regulatory oversight, especially on the correctness of AT&C loss estimation and a high accumulated financial loss revenue shortfall of ₹ 11,500 crores (DERC, 2015). The summer of 2016 witnessed many complaints about power outages. It is a matter of concern that the distribution companies have been resisting audit by the Comptroller and Auditor General of India (CAG) and RTI compliance. A clearer picture on Delhi will emerge only if the 2015 CAG audit report is made public[11], or if the Regulatory Commission takes proactive measures to analyse the performance of private companies[12].

11. In August 2015, the media had reported the findings of the CAG audit of Delhi DISCOMs, but in October, in response to petitions, the Delhi High Court has not allowed this report to be made public, saying that oversight should be by the DERC.

12. Appointment of Mr. K. Saini as the DERC Chairman by the AAP government in March 2016 has been challenged in the Delhi High Court. In September 2016, the Lieutenant Governor has set aside this appointment, adding to the confusion.

5.2.3 Distribution franchisees

Another model proposed to extend the benefits of increased efficiency from privatisation was to hand over some aspects of the distribution business in certain areas, especially urban high loss pockets, to private entities called franchisees. In this arrangement, the franchisee is expected to reduce AT&C losses through better billing and collection systems and through network investment in the franchised area. To ensure this, the DISCOM supplies power to the franchisee at a price decided by competitive bidding called 'input rate'. Tariffs for consumers in the franchised area are the same as for the rest of the DISCOM, and the difference between the DISCOM tariff and 'input rate' translates to revenues for the franchisee. In turn, the DISCOM earns fixed returns from a high loss area without increasing efforts in network investment, billing and collection. The determined input rate is linked to the change in average revenue per unit of sales (average tariff) in that region which is also called the Average Billing Rate (ABR). This arrangement insulates the DISCOM revenues from changes in tariff as the increase in average tariffs will increase the input rate and vice versa.

The experience with franchisees between 2007 and 2012 has been at best mixed and even disastrous in many cases. After the first such franchise in India was awarded to Torrent Power Limited (TPL) in 2007 for Bhiwandi, many contracts were awarded to other private players in other cities and they are all fraught with issues. The problems started from bidding itself with delays in takeover of franchisee areas as well as post-bidding dilution of contracts as in the case of Bhiwandi, Kanpur and Agra. In some cases (as shown in Table 5.2), the delay was for such long periods that the DISCOMs terminated the agreements citing changes in ground realities. The bidding documents also contained incorrect data, which would later impact revenue streams for DISCOMs. In the case of Torrent Power Limited's Agra franchisee, the baseline AT&C losses reported for the bidding process was 10% higher than the audited actuals (CAG, 2013).

With respect to post-bidding performance, Bhiwandi seems to be the only success story, as investments reduced transformer failure rate by 30% and brought down AT&C losses by 20% in the first 2 years (Chitnis, Dixit, Kadam, & Sant, 2009). In Agra, after the takeover, AT&C losses *increased* from 58.77% to 61.44% in 2010–11 (CAG, 2013). In all areas where a steep reduction is claimed, further analysis is not possible due to lack of proper baseline data and regular audits.[13]

13. Even in the case of Bhiwandi, the poster child for the franchisee experience, independent third party audits to verify crucial sales claims have not been carried out.

A crucial objective of franchising was to ensure revenue generation for the DISCOM. If the franchisee area has a rising number of unmetered or subsidised consumers, it will reduce the ABR and thus the input rate, affecting payments to the DISCOM. In order to assess the benefits to the DISCOM, it is imperative that an ABR audit, audit of subsidy claims, status of arrears, billing systems and database audit be conducted on a periodic basis (Chitnis, Dixit, Kadam, & Sant, 2009). However, there is no publicly available evidence of any audits (including baseline ABR) being conducted in any franchisee area. DISCOMs also face the risk of dealing with defaulting franchisees and termination of agreements which will increase their liabilities. Some areas where termination has taken place are highlighted in Table 5.2.

Table 5.2: Status and reason for termination of some franchisees

Area	Franchisee awarded to	Reason for termination and status
Aurangabad	GTL Limited	Non-payment of dues to the DISCOM
Jalgaon	Crompton Greaves	
Nagpur	Crompton Greaves	Delay in take-over
Kanpur	Torrent Power Limited	
Ujjain	Essel Utilities	Poor service quality and protests from consumers
Ranchi	CESC Limited	Delay in Execution; Termination being challenged in High Court
Jamshedpur	Tata Power	

Source: Various newspaper reports.

Franchisees are bound to ensure supply and service quality as per SERC regulations. However, in practice, they are treated as agencies outside the regulatory ambit and there is no regulatory scrutiny of service quality. There is also a need to focus on ensuring regulatory scrutiny of the franchisee bidding process, periodic performance audits, and rational allocation of revenue amongst licensee and franchisee. This can also be done during the tariff determination process of the DISCOM. Without regular audits and regulatory scrutiny, it is difficult to assess the performance of these franchisees. It is highly likely that franchisee arrangements have not increased benefits to DISCOMs or consumers. Even so, franchisees were being proposed by policy makers as an effective solution for loss reduction. The Shunglu Committee (in 2011) and the task force on private participation in power distribution (in 2012) suggested that the model should be implemented in 255 cities in India (Planning Commission, 2011; Planning Commission, 2012c). The Financial Restructuring

Plan in 2012 required all signatory states seeking bailouts to prepare a road-map for franchisees (MoP, 2012a).

Despite numerous issues with bidding, the Ministry of Power issued standard bidding guidelines for the selection of input based distribution franchisees only in 2012, after several franchisees were already awarded. This document has clauses with respect to a regulatory scrutiny of franchisee operations, conduct of periodic audits and the provision for additional power purchase by the DISCOM in case of a shortage for supply in the franchisee area (MoP, 2012b). Subsequent to the release of these guidelines, franchisees are increasing in number and spread across DISCOMs.[14]

It is quite clear that unless losses are extremely high and no other alternative exists, franchisees are not in the DISCOMs' interest, keeping in mind the potential revenue foregone, issues with employees[15], subsidies and difficulties with franchisee monitoring.

5.3 Power purchase

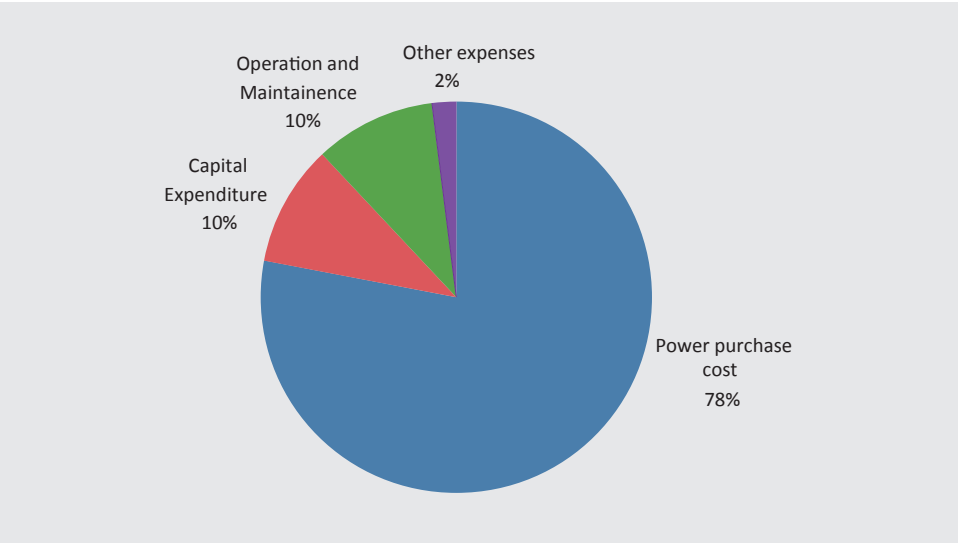
Each integrated SEB depended on its own generation and some power purchase from central and private generating companies to meet its demand. After unbundling, the introduction of Independent Power Producers (IPPs) and the eventual de-licencing of the power generation business, power purchase has become a major function of distribution companies.

As shown in Figure 5.1, power purchase cost accounts for about three-fourths of the total expenditure incurred, and therefore has significant impact on consumer tariff and finances.

14. As of 2016, the CESC and Tata Power (which are facing termination) were appointed as franchisees in Ranchi and Jamshedpur respectively. Franchisees have also been appointed in Bhagalpur (SPML Infra), Muzzafarpur (Essel Utilities) and Gaya (India Power) in Bihar and Kota (CESC) and Bharatpur (CESC) in Rajasthan. In Odisha, 14 out of the 20 divisions of CESU DISCOM have been awarded to franchisees (GoO, 2016).

15. For an overstaffed DISCOM, transferring employees from franchised areas to other circles would be difficult.

Figure 5.1: Average proportion of expenditure across major cost heads for DISCOMs (2012–13)



Source: (Planning Commission, 2014a).

Power procurement involves demand estimation to identify the quantum of power to be procured and then signing contracts with generating companies or trading licensees to meet this requirement. The final contract price is passed onto the consumers. Such contract prices could be cost-plus or discovered through bidding. Typically, these contracts are long-term (about 25 years) or medium-term (about 1 to 7 years). These contracts involve payments in two parts — a fixed annual payment to cover fixed costs, and variable charges to cover fuel and running costs. Short-term contracts involve single part payments and are procured at negotiated rates or via bidding. These contracts are subject to price volatility and should be typically used by DISCOMs only to cater to unforeseen variation in demand.

5.3.1 Demand estimation

Quantum of power procurement and sources are determined on the basis of long or medium-term demand estimation. Demand estimation, for about a 10–15 year period, is prepared by the CEA for all DISCOMs as part of the Electric Power Survey (EPS). The estimates are based on broad assumptions (like historical growth of consumption, projected economic growth) and are correlated to the objectives of government programmes (like achieving universal electrification). The methodology and model used for these forecasts are opaque and some of the

underlying assumptions are arguably problematic.[16] Moreover, the forecasting techniques used do not capture uncertainty, seasonality, extent of latent demand, and the dynamic nature of the electricity sector in India (Rallapalli & Ghosh, 2012). CEA demand projections have overestimated demand growth consistently (Purkayastha, 2001). In fact, a former regulator said that these estimates are based on "projections of current demand with the addition of new projects expected to come into operation" (Rao, 2002). Even today, this is a cause for concern, as the peak demand, energy requirement and load profile projections of the CEA are used as the basis for planning additional capacity at the national and DISCOM levels.[17] It is even used for arriving at capital expenditure plans for distribution and transmission infrastructure. In many cases, the EPS projections are used to justify power purchase by the DISCOMs, or capacity addition by the state generating companies.[18] Table 5.3 shows the extent of this consistent overestimation[19] of demand.

Table 5.3: Electricity demand projections vs. actuals across Electric Power Survey rounds

Electrical Power Survey Round	Time Period	Projected Average Demand Growth	Actual Average Demand Growth
14th	1988–95	12.45%	8.75%
15th	1998–02	6.85%	4.64%
16th	1999–05	7.04%	4.40%
17th	2005–12	7.81%	5.75%
18th	2012–17	9.46%	4.91*%
	2017–22	7.27%	--

* Demand for 2016–17 based on CEA estimates in the load generation and balance report.

Source: Various electric power survey reports, CEA publication on growth of Indian Electricity Sector from 1947–2015, Load Generation and Balance report for 2016–17. (CEA, 1991; CEA, 1995; CEA, 2000; CEA, 2007; CEA, 2011; CEA, 2015a; CEA, 2016a; Shahi, 2006).

16. For the five year period between 2012 and 2017, the CEA assumes a GDP growth of 8% to 10%. These assumptions were not revised even after the Planning Commission revised the annual growth rate to 7% for the 12th Five Year Plan in 2013.

17. An example of this is Bihar DISCOMs using CEA estimates for their medium term planning efforts (BSPHCL, 2012).

18. Along with other considerations, UPPCL in Uttar Pradesh used CEA EPS projections to deviate from bidding guidelines to procure 6000MW of power which was approved by the commission (UPERC, 2014). The Rajasthan Urja Vikas Nigam Limited (RUVNL) also used EPS estimates to justify power procurement despite deviation from bidding guidelines for 1000 MW. This was also approved by the Rajasthan Commission (RERC, 2015).

19. Overestimation in the 17th and 18th EPS could also be because the assumptions consider 100% household electrification. It is not clear, however, how demand for newly electrified households is considered.

Table 5.3 shows that demand growth assumed by the CEA was often 30% to 40% higher than the actual demand growth during that period. In spite of this, there has rarely been a review of estimates[20] or any change in methodology[21] to integrate econometric forecasting techniques in the current approach. The CEA also projects and publishes demand estimates on an annual basis in the Load Generation and Balance Report. These estimates have also been questioned for flaws in methodology.[22]

DISCOMs undertake a demand estimation exercise for the tariff determination process usually for a one year period or for up to a five year period. Such estimations are usually based on past trends and state level policies. The demand forecast made by utilities is heavily guided by CEA demand projections and are often cross-checked with the EPS estimates.[23] Like CEA estimates, DISCOM estimates are also seldom reviewed and suffer from methodological flaws. Demand forecast exercises by the DISCOM do not take into account macroeconomic indicators, actual progress of government development programmes, environmental/resource factors (e.g. depletion of ground water reserves), elasticity of sales to tariffs, historic trends of migration of consumers to open access and renewable options, change in appliances used, possible changes in load profile, etc. Energy efficiency and conservation measures are crucial to reduce power procurement without curtailing necessary consumption. However, they do not feature prominently in the strategies of the DISCOM nor is their impact on demand accounted for during forecasting exercises. Please see Box 5.1 for more details on energy efficiency.

In some cases, past trends also do not inform future growth projections. DISCOMs of Maharashtra, Madhya Pradesh, Tamil Nadu and Gujarat, which have faced

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20. The draft of the 19th Electric Power Survey has not been released yet but could have a significant downward revision in demand estimation. The draft National Electricity Plan of the CEA for 2017-2022 shows a significant downward revision in demand from the 18th EPS. It also accounts for reduction in demand due to energy efficiency and conservation methods as well as reduction in demand due to sales migration to captive sources and rooftop solar.(CEA,2016).

21. The CEA uses partial end use methodology, a combination of time series and end use methodology, to forecast demand for the five years and trend exploration to estimate demand for each plan period (CEA, 2011).

22. Discrepancies were pointed out in the estimates of the CEA and POSOCO in January 2015, with CEA estimates being higher. The discrepancy was because the CEA would use peak demand estimates from different days of the month for the various regions, instead of adding the regional peak demands met for each of the regions on the same day as POSOCO correctly does (Sasi, 2015).

23. Karnataka ERC regulations on load forecast specifically mention that "the short-term and long-term forecast as published by the CEA, shall form the basis for Generation, Transmission & Distribution Planning." (KERC, 2009, p. 5).

significant migration of consumers to open access and captive options, continue to project optimistic demand growth in cross-subsidising segments. It is to be noted that maximum migration of sales occurs in the case of HT industrial consumers. The figures given in Table 5.4 illustrate this trend.

Table 5.4: Comparison of projected sales growth with actual sales growth trends

HT Industrial sales growth rates	Period	Maharashtra (MSEDCL)	Madhya Pradesh DISCOMs
5 year actual growth rate	2009 - 14	2%	8%
3 year actual growth rate	2011- 14	-4%	1%
Actual year on year growth	2013 - 14	-11%	0.2%
Growth rate projected by DISCOM	2016	***7%***	***4%***

Source: Tariff petitions for respective years for MSEDCL and Madhya Pradesh DISCOMs.

Demand estimation forms the cornerstone of the business plan of any company. In the case of DISCOMs, it is unfortunate that the process is not carried out seriously and with scientific rigour. This laxity in demand estimation and the tendency towards overestimation is proving to be costly for DISCOMs, as the power procured via long term contracts with fixed payment schedules far exceeds the demand for such power.

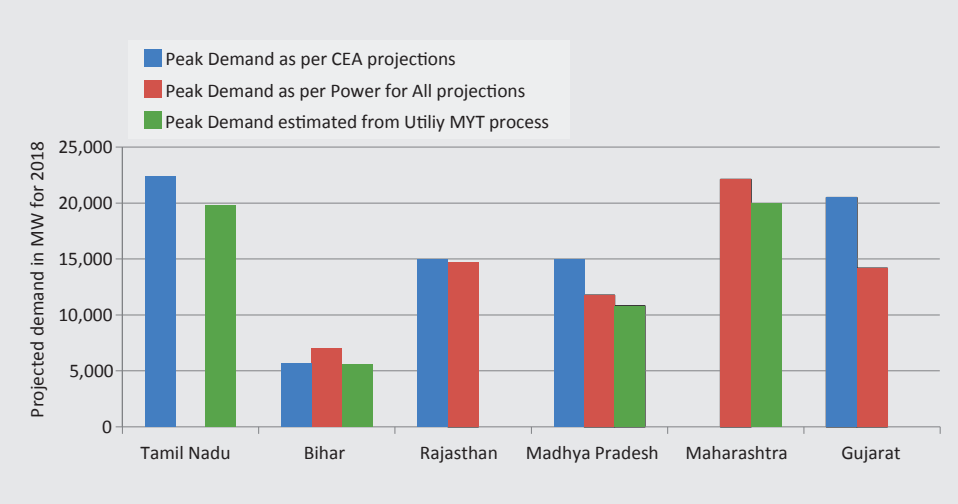
The 'Power for All' programme and UDAY[24] have demand estimates at least till 2018–19 (GoI, 2016). These estimations are a one-time exercise with the aim to address specific issues of electricity access and financial indebtedness of DISCOMs. The 18th EPS was released in 2011 and projections were made using 2009 as the base year. In spite of the time lag, the estimations for each state under PFA were also based on projections by the CEA in the 18th EPS.

Figure 5.2 shows the discrepancy between the demand estimates for the year 2017–18 under the 18th EPS, estimations used in the utility tariff determination and other regulatory processes, and demand projections used in the Power for All documents. Utility projections for all states except Tamil Nadu were conducted in 2015–16, and Power for All estimation is from 2014–15 for Rajasthan and 2015–16 for other states. Figure 5.2 is an indicative illustration of variation in projections due to the

24. Estimations are provided for revenue from sale of power but this is not possible without an estimation of sales and demand.

variations in the year in which estimations were conducted. As the CEA projections are dated, it is a matter of concern when the later projections made by the utility and under Power for All in some states are quite similar to CEA projections.

Figure 5.2: Demand estimations for 2017–18 for DISCOMs in six states from various sources[25]



Source: Power for All plans for various states, the 18th Electric Power Survey, DISCOM MYT petitions.

The divergence in estimates is most stark for utilities facing sales migration such as Maharashtra and Gujarat where demand from certain segments is falling so rapidly that the dated CEA estimates do not hold true. However, as shown earlier, these estimates also seem optimistic given past sales growth. Demand estimation methods therefore do not seem to reflect the present position or changing realities of DISCOMs. Considering these estimates as the basis for signing long-term power procurement contracts can result in significant costs for consumers. In the coming years, demand estimation for the DISCOM is going to be more challenging with increasing number of consumers using open access, captive generating plants and rooftop solar systems to cater to their demand.

25. Rajasthan and Gujarat have not provided projections for the year 2017–18 in the tariff determination process. Tamil Nadu DISCOM had provided estimations as part of a demand and supply forecast exercise before the ERC in 2012 (TANGEDCO, 2012). As on December 2016, Tamil Nadu had not joined the PFA initiative and thus there are no estimates. The CEA demand projections for Maharashtra include Mumbai whereas the utility projections and PFA projections are only for MSEDCL, the utility serving all other areas in the state except Mumbai. Therefore CEA projections for Maharashtra were not used in the comparison in Figure 5.2. Where demand was not available, the load factor used in the Power for All documents is utilised to estimate demand from sales projections.

Box 5.1: Energy Efficiency

Energy Efficiency (EE) involves activities in three parallel streams: energy conservation (reducing energy use), end-use efficiency (improving conversion efficiency to get the same output with less use of energy) and demand side management (shifting the time of use of energy to optimise energy supply costs). A good EE initiative also recognises that people require 'energy service' (lighting, cooking, cooling, heating, communication, entertainment, shaft/rotary motion, etc.) and not energy itself. It also recognises that efforts in EE should span planning, operation and monitoring. Hence it makes sense to explore if an energy service can be rendered through an alternate energy source, by better architecture, better planning, etc. or if the quantum of energy service can be reduced (e.g. reduce people's need to travel by better town planning). EE benefits the consumer, energy service provider as well as society. For developing countries like India which are witnessing rapid infrastructure growth, EE is an opportunity to avoid the inefficiency lock-ins. Hence it deserves the highest priority over energy supply planning or renewable energy. We provide a broad overview of EE, with higher focus on electricity.

Attention and efforts on energy efficiency started during the oil crisis of the 1970s with several initiatives towards conservation, integrated planning and energy efficiency. But these were mostly limited to research and awareness creation. The Energy Conservation Act (2001), National Mission on Enhanced Energy Efficiency (NMEEE, 2008) and recent initiatives triggered by climate concerns have given a big thrust to EE. The Bureau of Energy Efficiency (BEE) set up in 2002 and state level nodal agencies (which also look at renewable energy) are expected to promote EE in the country (Vasudevan, Cherail, Ramesh, & Jayaram, 2011). This promotion has been done through efficiency programmes for industry, buildings and appliances.

The potential for electricity savings in different sectors is quite high — approximately 30% in agriculture, 25% in commercial and residential, and 15% in industry (Singh, Sant, & Chunekar, 2012). Commercial and industrial consumers have been taking up EE programmes on their own since they improve productivity and make them competitive. There have also been central government driven programmes such Perform, Achieve & Trade (PAT) for selected industries and Energy Conservation Building Code. The case of small consumers and agriculture has been different. The initial

EE programmes in this area were mostly pilots implemented by electricity DISCOMs. These programmes had limited impact since EE was not considered as a high priority activity, there was no independent monitoring, and DISCOMs were not keen to reduce consumption by paying consumers.

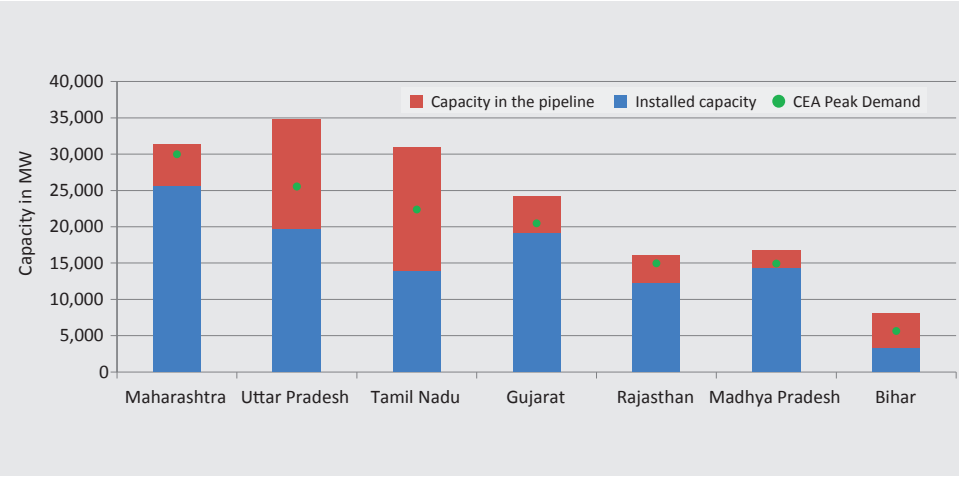
After setting up of the BEE and formulation of the NMEEE, there has been some progress in EE programmes in industry and buildings. Appliance star labelling programme of the BEE did introduce some efficient appliances in the market and produce public awareness. But the uptake of efficient appliances has been low due to reasons like high one-time cost. In the past few years, there have been EE programmes that are implemented at a large national scale and aim to transform the market. These include the Domestic Efficient Lighting Programme (DELP), supplying LED lights to houses, the efficient fan programme to replace fans, and the efficient agriculture pump programme. Power For All initiative of states include programmes to promote efficient appliances and improve energy efficiency in municipalities. The DELP has seen the largest scale of implementation with nearly 16.5 crore LED bulbs distributed as of end September 2016, with a reported peak saving of 4,318 MW (MoP, 2016c).

It is indeed a welcome sign that more attention is being paid to EE by the national and state governments, industry and civil society. More importantly, today there are large scale implementations of various programmes, with high investments, compared to small pilots a few decades ago. But if these programmes have to yield sustained savings in fuel use and reduction of environmental impacts, a few steps need to be urgently taken. All consumers including government offices, who are expected to be more conscious of lifetime cost, should take up more aggressive EE initiatives. Load surveys and energy audits have to be conducted to arrive at a better understanding of energy use patterns. EE programmes have to be planned through a more participatory process. Mechanisms and institutions for assessing base case energy use and validating actual savings through EE measures have to be strengthened. Demand estimates should be reduced based on progress in EE programmes, and reward for implementation should be based on actual savings, not estimated savings. Finally, in case of appliances like fans, refrigerators and agriculture pump sets, there is a need to transition beyond the current five-star efficient appliances to super-efficient ones, which can result in 10–20% more savings (Singh, Sant, Bharvirkar, Kumar, & Phadke, 2011).

5.3.2 Power procurement plan

To make matters worse, power procurement is often not commensurate with even these flawed demand estimations, as shown in Figure 5.3. The figure shows the capacity projected till 2018 for DISCOMs in various states. Even after excluding renewable energy capacity addition, most states have projected capacity far in excess of the projected demand (which itself may be an overestimate).

Figure 5.3: Planned capacity addition and future demand estimates across a few states[26]



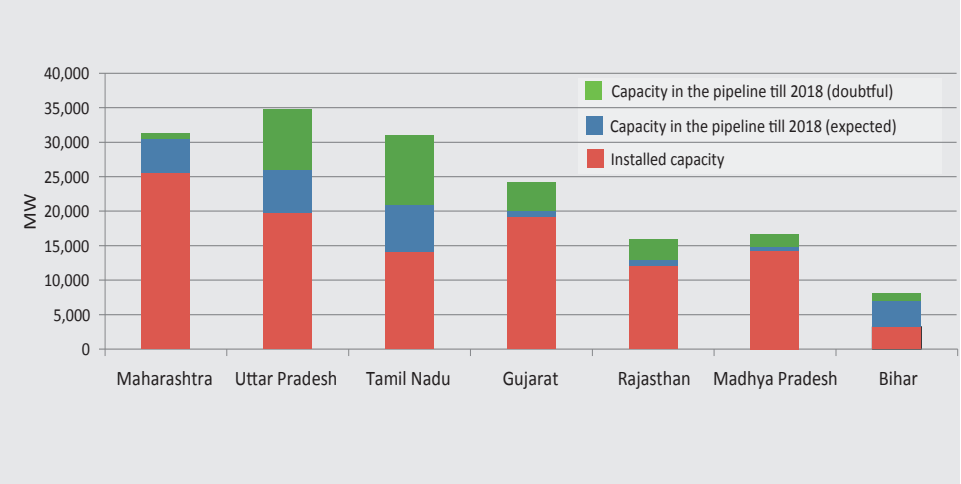
Source: Petitions of DISCOMs and 18th Electric Power Survey.

At the state level, power procurement is often fuelled by the crisis driven need to address immediate shortages. Due to this, capacity and power procurement in the pipeline often stacks up higher than future demand. If planned capacity materialises, DISCOMs are stuck with surplus power. But it is doubtful if all the capacity addition would materialise, since there may be delays in commissioning or termination of power purchase contracts. In such a situation, the DISCOM would face another shortage induced crisis. There is no systematic and regular process to track capacity in the pipeline. Capacity addition and power procurement estimates of state governments and DISCOMs are often unrealistic, ambitious, ad-hoc and are seldom monitored or revised over time. Delays in capacity addition can increase the costs to DISCOMs due to accumulating interest during construction.

26. The installed capacity is as on 2015–16 for states. Renewable capacity was not included to highlight planning issues with thermal capacity addition. Maharashtra includes Mumbai and MSEDCL.

Shortages due to such delays can also lead to increased costs due to short-term power purchase, else it results in load shedding. Figure 5.4 shows the expected capacity addition in the pipeline till 2018 based on CEA reports (CEA, 2016c).

Figure 5.4: Installed capacity: current and projected till 2018 across a few states[27]



Source: Tariff orders, CEA's broad monitoring status report and various DISCOM petitions.

It is important to note that in most states, more than half the capacity addition and power procurement planned for in the next two years is unlikely to materialise due to delays, issues of compliance with statutory requirements, etc. This could fuel even more power procurement in the anticipation of shortages and the possibility of load shedding in the interim. This estimation does not include the substantial, planned renewable energy capacity addition discussed in Chapter 4 on renewable energy. ERCs and DISCOMs have been treating renewable energy procurement only as a matter of statutory compliance to meet the renewable energy purchase obligations. Planning for large scale procurement of renewables should take into account demand projections, change in load profiles as well as conventional capacity in the pipeline. As power procurement planning is not agile and dynamic, there is a high likelihood of states having contracted power in excess of their current demand. This excess capacity or 'surplus' power comes with the possibility of backing down of generation capacity, which entails further costs as detailed below.

27. The installed capacity is as on 2015–16 for states. Renewable capacity was not included to highlight planning issues with thermal capacity addition. Maharashtra includes Mumbai and MSEDCL.

5.3.3 Backing down and excess capacity

As explained earlier, most power procurement contracts have a two part payment system. In such cases, if power from a generator is not requisitioned despite being available, the DISCOM has to bear the fixed charges as per the contract. DISCOMs are supposed to schedule power such that plants with lower variable costs are given priority over those with higher variable cost. This is called merit order scheduling. It ensures that capacity with the least fuel cost is used for generation first. In case supply exceeds demand at any time, some plants are not allowed to generate or are 'backed down' due to their high variable costs. The DISCOM will have to bear the fixed cost of this 'backed down' plant. In 2013–14, a sample study of CEA estimated that about 96 BU[28] were backed down across India (CEA, 2015b). This itself accounts for 10% of the power available for supply from generating stations that year and had significant cost impacts.[29]

Backing down has also resulted in operational issues due to stockpiling of coal. In 2013, the Gujarat State Electricity Corporation Limited (GSECL), the state generating company of Gujarat, had accumulated coal worth ₹ 419 crores at various stations. Stockpiling resulted in deterioration of coal quality and also exposed GSECL to the risk of losing coal linkages as coal off-take from mines is time-bound (GERC, 2014). State generating companies in Haryana and Uttar Pradesh are also facing similar stockpiling due to backing down and have requested Coal India Limited to stop supply to some of the plants (Jai, 2016).

Most of the newly added capacity across DISCOMs is much more expensive than the average cost of power purchase. In the face of slower than anticipated demand growth, these plants have a high risk of being backed down. In a regime where most costs are being passed on to consumers, the DISCOMs have no incentive to increase efforts to procure low cost power. Therefore the inefficient trend of high cost capacity addition and backing down is bound to continue.

Gujarat, Maharashtra and Madhya Pradesh are among the states which have been having surplus power for a while now due to slow sales growth and ambitious

28. This estimate is based on CEA's analysis of 143 thermal power stations with an aggregate capacity of 1,32,624 MW. This accounts for about 60% of India's installed thermal capacity. The magnitude of backing down reported is thus an underestimate.

29. Assuming a conservative ₹ 1 as fixed charge per unit generated, this implies that DISCOMs paid an approximate sum of ₹ 9,601 crores in 2013–14 for capacity which did not supply any generation. This is a conservative estimate as the average fixed cost per unit for central sector generating stations was about ₹ 1.08 per unit for coal based plants and ₹ 0.87 for gas based plants. The fixed cost figures for state owned generating stations are much higher.

capacity addition. However this has not quelled capacity addition plans as shown in Table 5.5. As per projections and government estimates, most DISCOMs seem to be heading in the direction of the DISCOMs in these states.

Table 5.5: Instances of backing down of generation in a few states

State	Instances of backing down in recent past	Capacity planned to be contracted by DISCOM by 2018
Gujarat	In 2011-12, an average of 1000 MW was being backed down. This was about 9% of the peak load that year (GERC, 2013; CEA, 2013b). In 2015, the same DISCOMs backed down an average of 4,322 MW which is about 32% of the peak load (CEA, 2015c).	4,196 MW out of which 2,400 MW is from the state generating company
Maharashtra	In 2016–17 MSEDCL plans to back down 5,359 MW (MSEDCL, 2016b). This accounts for 26% of peak load for the year (CEA, 2016a). 30% of this capacity belongs to MSPGCL, the state run generating company.	5,693 MW of which 3,939 MW is from the state generating company
Madhya Pradesh	More than 11,900 MUs projected to be backed down by DISCOMs in 2016–17. This works out to about 1,866 MW[30] which accounts for 17% of the peak load.	1,838 MW none of which is from the state generating company
Punjab	In 2016-17 PSPCL plans to completely back down 1,248 MW. This works out to about 11% of peak load that year (PSERC, 2016).	1,696 MW of which 99% is from central sector generating stations

Source: Various regulatory orders and DISCOM petitions.

With more and more supply options such as open access and grid connected rooftop solar, backing down of excess capacity will become a new reality for many DISCOMs. Hence, it is important to think through how this excess high-cost capacity is to be channelized. One way of reallocating power between surplus and shortage states could be for DISCOMs with consistent 'surplus' to sign medium-term contracts with DISCOMs planning to add capacity. This could also mitigate further capacity addition. Sales of non-requisitioned power by generators on a revenue sharing basis with the DISCOM, as envisaged in the 2016 Amendment of the National Tariff Policy, is another possibility to manage surplus. Another arrangement could

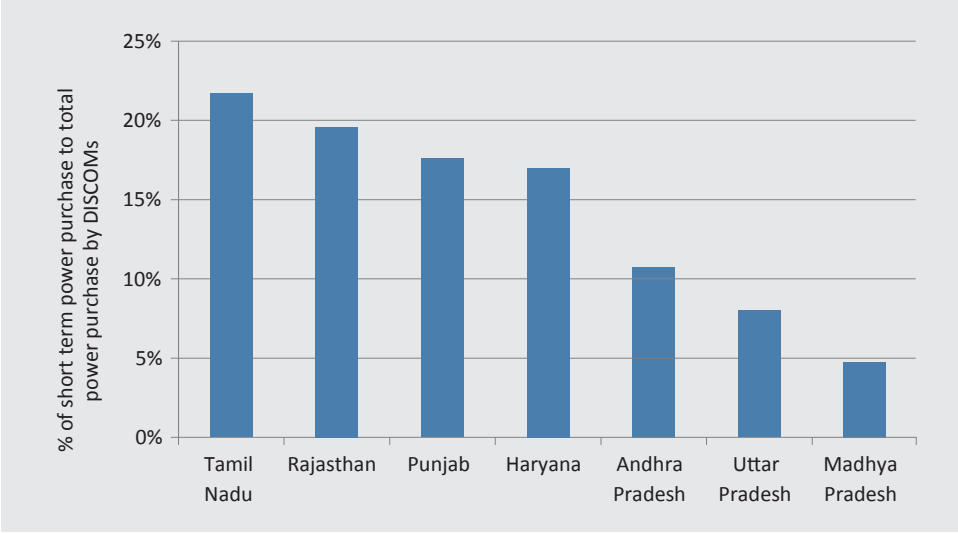
30. Using the load factor assumed in the Power For All Plan for Madhya Pradesh for the year 2016–17 (MoP and GoMP, 2015)

be to use the backed down capacity to meet the power requirement of providing electricity access to newly electrified households, ensuring reliable power for all in less developed areas. This is possible if the consumers or the DISCOMs are charged low rates for the power. An option to ensure the power is low cost is that the supplying DISCOM foregoes part of the fixed cost.

5.3.4 Short-term contracts

Till 2012, most state-owned DISCOMs relied heavily on short-term power purchase to meet their growing demand, and at the time market price was also considerably high. Figure 5.5 shows the high percentage of state-wise short-term purchase of DISCOMs in 2011-12.

Figure 5.5: Share of short-term power purchase in total power purchase in 2011-12 for a few states



Source: (Chitnis, Dixit, & Josey, 2012).

It is interesting to note that the DISCOMs which heavily relied on short-term power are also among the most indebted. With more capacity being available after the 11th Five Year Plan period, the market prices and the DISCOMs reliance on high cost power reduced.

If most state-owned DISCOMs are guilty of overambitious and expensive capacity addition plans, private DISCOMs seem to avoid long-term power purchase contracts and continue to be highly dependent on short-term arrangements. This

is shown in Table 5.6. In the year 2014–15, except in the case of Delhi, whose DISCOMs receive a significant share of power from central sector generators, all private DISCOMs have a heavy dependence on short-term power.

Table 5.6: Short-term power purchase by private DISCOMs in 2014–15

Quantum and impact on short-term power purchase[31]	Mumbai		Ahmedabad and Surat	Kolkata	Delhi		
	RINFRA-D	TPC-D	TPL	CESC	BRPL	BYPL	TPDDL
Price (₹/unit)	4.55	4.49	5.33	3.36	4.44	3.94	4.22
% of total power purchase	16%	31%	48%	19%	8%	5%	0%
% of total power purchase cost	13%	22%	35%	34%	8%	4%	0%

Source: Various tariff orders.

The significant financial losses and regulatory assets of some private DISCOMs have been attributed to poor power procurement planning and increased dependence on short-term power purchase (Kasturi, 2013; PEG, 2016b). Much like the heavily indebted state-run DISCOMs, private DISCOMs relied on short-term markets for a large share of their demand even when market prices were high.

It is important to note that no private DISCOM has contracted long-term power using competitive bidding, even though the same private players also own generation businesses were capacity has been contracted via competitive bidding. When private DISCOMs sign long-term power contacts, it is notably with their sister concerns at high costs.

In 2012, the Ministry of Power introduced guidelines for power procurement of short-term power which said that all short-term power is to be contracted via competitive bidding. The guidelines also mentioned the introduction of an e-bidding platform to procure power via a reverse auction system in not less than five years. This platform, called Discovery of Efficient Electricity Price (DEEP), was launched in 2016. Unlike power exchanges where contact durations can be only as long as a week, contract durations on the DEEP platform can even be year-long and the bidding process is transparent (MoP, 2016d). The platform has been allowing

31. Data for all DISCOMs except Delhi for 2014–15. Data for Delhi DISCOMs is for the year 2013–14.

bidding for medium term contracts (1 to 5 years) since August 2016 (PIB, 2016).[32] DEEP can be useful for DISCOMs who want to find buyers for surplus capacity. A few states have participated in this process and the rates discovered are comparable to the prevailing short-term rates. With more participation in the coming years, the efficacy of the platform will become clearer.

5.3.5 Regulation, integrated planning and the way forward

The regulator has a critical role to play in efficient power procurement and this role will become decisive with increased role of markets, sales migration and changes in demand due to proliferation of renewables. Even though the implications of demand estimation, power purchase planning, on costs and reliable electricity access are clear, SERCs make limited efforts to mandate utilities to undertake periodic demand estimation that is rational and realistic, and plan capacity based on such requirements. Many SERCs have reprimanded DISCOMs for not complying with directives to reduce reliance on short term power. However, no SERC has imposed penalties or taken stricter measures to ensure compliance. Regulators also do not exercise their powers to hold generators accountable for delay in commissioning and seldom account for delays while reviewing medium term power procurement plans. This lack of oversight is predominantly responsible for ambitious power procurement plans, increased costs and backing down.

To overcome this, as a first step, the commission can look at feasibility of projects considered and approve power procurement only if the project fulfils certain criteria. The criteria could include completion of land procurement, obtaining fuel linkages, obtaining necessary clearances, etc. This will help form a realistic estimate for capacity addition in the pipeline with which to compare changes in demand. Any additional power procurement should be evaluated considering realistic assessment of demand and capacity in the pipeline. If shortages are anticipated only in the interim period till long-term projects kick in, the commission should advocate for medium-term or short-term contracts for duration of more than one year via competitive bidding.

Power procurement planning is not just linked to demand estimation and capacity in the pipeline but also must consider transmission bottlenecks, fuel constraints and fuel sector changes. Further, the planning exercise should also take into account the nature of the demand. DISCOMs could think of short-term contracts

32. Based on guidelines for medium term power procurement notified in 2014 and further amended on May 2015.

of seasonal durations (say three months) or more medium-term contracts in their mix to respond to changing demand. Current practices of demand estimation and power procurement leave the state run DISCOMs and their consumers unprepared for changes in the near future including sales migration.

5.4 Experiments with consumer choice in the distribution sector

Following the opening up of the generation segment, creating a large number of competing buyers for the power generated seems like a logical step to deepen markets. A typical DISCOM supplies power to its consumers by wheeling or transferring procured power through its network. Consumer choice implies that a consumer can chose her power supplier and have that power wheeled through the DISCOMs' network. There are two models to promote consumer choice currently operating in India. One is through open access, where consumers can sign independent contracts with generators of their choice and wheel that power through the DISCOM network. The other unique model which is restricted to Mumbai, allows one to choose between two companies for supply of power. This power is wheeled using the existing DISCOM's network. The parallel licensing model in Mumbai is similar in some respects to the introduction of multiple supply licensees as suggested in the proposed amendment to the Electricity Act (MoP, 2014b). Therefore, the lessons from Mumbai need to be taken into account while considering major structural changes in the sector to usher in competition. These two models will be discussed in this section.

5.4.1 Open Access in distribution

Open access refers to non-discriminatory access to the distribution and transmission network which allows consumers to choose the generator they prefer at a mutually agreed price. The distribution and transmission companies are compensated for the use of their networks. Such an arrangement can be put in place directly between the consumer and the generator via a trading licensee or an exchange. Open access is rolled out in various states based on transmission and distribution open access regulations. Key features of the distribution open access regulations are discussed in Table 5.7.

Table 5.7: Key features of distribution open access across states

Criteria	Key provisions
Eligibility	Consumers with connected load of more than 1 MW are eligible for open access. This includes a large majority of High Tension (HT) cross-subsidising consumers.
Duration	Open access can be short term (< three months), medium term (3 months to 3 years) or long term (12 years to 25 years).
Major Charges	• Relevant transmission charges, transmission loss payment • Wheeling charges which compensates the DISCOM for use of the distribution network • Cross-Subsidy Surcharge (CSS) to compensate the distribution company for loss of cross-subsidising consumers due to open access • Payment of fixed charges for demand contracted from DISCOM • Standby charges for drawing more power than contracted from DISCOM • Additional charge for capacity backed down due to open access, if applicable
Application	Includes application process, time frames, submission of bank guarantees, etc.
Role of various agencies	Responsibilities of the DISCOM, transmission companies, load despatch centres and open access consumers.

Source: Open Access regulations across states.

Operationalisation of Open Access

Even with almost all SERCs notifying regulations to operationalise open access, it has had a slow and shaky start. The main reason for this is the stiff resistance from DISCOMs to process applications. This resistance is due to the loss of sales and consequently revenue from high paying, cross-subsidising consumers which could further deteriorate their precarious financial position. This is evident from Table 5.8.

Table 5.8: Extent and impact of open access in a few states

State	Extent and impact of open access
Maharashtra	In 2012–13, MSEDCL lost about 2700 MUs of sales to open access. The consequent loss of revenue was responsible for 26% of the tariff increase borne by consumers in 2013–14 (MERC, 2014).
Tamil Nadu	TANGEDCO in the year 2011–12 suffered an estimated loss of ₹ 1573 crores, despite a high Cross-Subsidy Surcharge (CSS), due to the migration of almost 40% of the HT industrial consumers (TNERC 2012).
Punjab	In 2015-16, PSPCL lost 2036 MUs of sales to Open Access. There are about 434 industrial consumers with a connected load of 1732 MW availing open access (PSERC, 2015; PSERC, 2016).

Source: Various state regulatory orders.

Despite the levy of CSS and recovery of fixed costs from the consumers, DISCOMs still are impacted financially due to open access sales. This is due to the current tariff design, sales and consumer mix, and power purchase costs of the DISCOM. A high level of cross-subsidy in tariffs and a large volume of cross-subsiding consumers in the sales mix can lead to significant financial impacts in case of migration. The Cross-Subsidy Surcharge (CSS) levied on open access consumers is designed to cater to this loss, but may not do so adequately.

Cross-subsidy surcharge and tariff design

The National Tariff Policy, 2006 prescribed a formula to estimate the rate of CSS payable. The prescribed formula in the guiding policy was adopted by many SERCs even though it was not suited to estimate compensation given the state realities. This is especially true in states with significant sales to cross-subsidising categories and substantial high cost power purchase. It would also not capture the impact of loss of such sales in states with poor networks and a large number of non-electrified or newly electrified consumers (MoP, 2006a). The 2016 amendment to the National Tariff Policy suggests a different framework, and makes it clear that the states are allowed to adopt their own methodology for estimating CSS. To prevent CSS rates from curtailing open access, the 2016 amendment prescribes that it should not be higher than 20% of that category's average tariff (MoP, 2016e). If such a cap on CSS is adopted across states, it could effectively prevent regulators from levying CSS rates which make open access unviable. Besides CSS, fixed charges levied are not reflective of fixed costs incurred in most DISCOMs. As open access consumers only pay the fixed charges for the demand they have contracted from the DISCOM, the quantum of fixed costs recovered from them could be lower. In 2013–14, Gujarat

DISCOMs sought and obtained relief for ₹ 201 crores due to under-recovery of fixed costs due to open access sales migration of about 1491 MUs (GERC 2014). A decade after the introduction of open access, it is surprising that hardly any steps have been taken by regulators or DISCOMs to adapt tariff design to sales migration and determine CSS based on state realities to mitigate DISCOM losses due to open access.

Nature of power contracted by DISCOM

During shortages, migration of consumers can reduce demand such that DISCOMs can avoid high-cost short-term power purchase or reduce load shedding. SERCs of Maharashtra, Uttar Pradesh, Bihar and erstwhile Andhra Pradesh have reduced the Cross-Subsidy Surcharge (CSS) to zero during power shortages in order to make open access more lucrative.

If a DISCOM has adequate or surplus power, loss of sales due to open access could result in backing down. In 2013–14, about 1104 MW contracted by Gujarat DISCOMs was stranded due to open access with the utility continuing to bear the fixed charges. This loss is compensated with the levy of additional charges. As of 2016, many SERCs including those of Haryana, Gujarat, Maharashtra, Rajasthan and Punjab levy this charge. The dynamics of sales migration and power procurement have already been discussed in detail in Section 5.3.3.

Short term open access transactions

Short-term open access lets consumers switch between the DISCOM and market for a short period (often on a daily basis[33]) and at a short notice. Depending on seasonal variation of power availability and market prices, the consumer can opportunistically switch between market and DISCOM power, depending on which is cheaper. In most cases, the duration of such open access is less than a month and this increases uncertainty in power purchase planning for the DISCOM. In spite of this significant risk, most SERCs permit short-term open access. More than 80% of MSEDCL's open access consumers in 2015–16 were short term. Tamil Nadu, while facing acute shortages and under severe financial stress, removed the limit of connected load to qualify for open access. This resulted in large industries in the state contracting small amounts (30 to 50 kVA) of power via short term open access during industrial power holidays and overdrawing above the limit permitted. This

33. Most open access transactions on the power exchanges occur on a day ahead basis.This phenomenon has also been recorded in many regulatory orders.

practice continued despite the imposition of penalties and caused load shedding for regulated consumers (TANGEDCO, 2012). In a petition before Punjab ERC, the state utility PSPCL highlighted various issues due to this opportunistic switching. This included unpredictability of power procured by open access consumers on a day ahead basis, the risk of load shedding of regulated consumers and avoidable use of DSM due to unpredictability in demand (PSERC, 2015, p. 2).

Short-term open access is not desirable from a market development point of view, especially in the Indian context when the markets are nascent. The large seasonal, regional variation in availability and prices, combined with the present level of information asymmetries in India's fragmented power markets, implies that DISCOMs cannot requisition power as and when needed to cater to the variable demand of short-term open access consumers. DISCOMs will have to plan to procure this capacity and bear the high risk of it not being requisitioned by short-term open access consumers at all. Conversely, they might have to bear the high cost of additional unplanned power procurement for these consumers when they switch to the DISCOM for supply. This opportunistic switching makes power procurement and other operations challenging and has a significant impact on finances. Most of the open access in India is short term, which implies that consumers are unwilling to bear the risk of procuring supply from the market. Though this arrangement benefits open access consumers, it poses significant burdens on small consumers who are supplied by the DISCOM. These consumers have to bear the risk of load shedding or the cost of backing down for the benefit of open access. ERCs should have addressed this issue by limiting short-term open access to exigent circumstances at a high premium. Open access should have only been provided for a duration greater than one year in order to mitigate risk.

Policy and planning approach

Open access has had mixed results internationally and in a nascent electricity market like India, operationalizing open access needs to be done carefully and in phases. The impact of open access on DISCOMs and its consumers as well as the market could be significant in the future as volumes pick up. Many of these impacts on DISCOM operations and finances can be mitigated through a context specific approach and constant monitoring of the roll out of open access on power purchase planning and finances of the DISCOM as well as market operations. However, most state agencies have not tried innovative ways to address these issues, perhaps because of the lack of interest in promoting open access.

Over the years, despite the barriers and operational hiccups, open access has picked up in various states due to increased tariffs or poor supply from the DISCOM. In 2013–14, 86,973 MUs which accounts about 9% of the total power requirement that year were due inter-state open access consumers (Standing Committee on Energy, 2015). The quantum of intra-state open access is unknown. Lack of data and analysis also makes it difficult to study trends and identify issues with operationalising open access. In fact, information on number and type of open access consumers, duration of open access, sources of power for open access consumers and daily or seasonal variation in quantum of open access is not reported by the distribution companies nor analysed by regulatory commissions on a regular basis.

The centre-state tussle in the power sector is apparent in the story of operationalising open access, and has a role to play in its sporadic rather than planned development. The centre, with the motivation to encourage industry, has been pushing open access within states. In order to give open access a thrust, in 2011, the Ministry of Law and Justice in consultation with the Attorney General of India had opined that SERCs cannot regulate the tariffs of consumers with a connected load of 1 MW or more (MoP, 2011). Such a measure would have encouraged long-term open access and forced DISCOMs and state level actors to evaluate power procurement, contract and tariff design and market operations. Without a roadmap for implementation, adoption of this interpretation would have also meant increase in financial losses and operational complications. No SERC adopted this interpretation which was provided at the behest of the Ministry of Power (MoP, 2011). However, the same ERCs also permitted short-term open access which by its very nature can have significant impact on the finances, planning and operations of DISCOMs.

The central government seems committed to promote open access, but has not been effective in addressing the many questions before the state governments, including issues with power purchase planning, possibility of gaming by consumers and generators, impact on DISCOM finances, and generation scheduling.

The proposed amendments to the Electricity Act aims to broaden and deepen the market for larger consumers by mandating consumers with a connected load of greater than 1 MW to arrange for their own supply via open access (PEG, 2015). If the DISCOM is to have unregulated contracts with such open access consumers, power could be supplied to them by curtailing power supply to low paying small consumers. Besides addressing these unresolved issues, mainstreaming open access without a framework, adequate checks and regular monitoring can have grave impacts on the DISCOMs and its consumers.

5.4.2 Parallel licensing in Mumbai and lessons for competition

Mumbai is the only city in India where consumers can choose their power supplier via the parallel licensing arrangement.[34] Such a choice is thought to lead to competition which can increase efficiency and lower tariffs. However, operationalisation of parallel licensing in Mumbai has been contrary to this expectation, as it has taken place with a series of unnecessary litigations, skyrocketing expenses, steep consumer tariffs and regulatory failure (PEG, 2016b).

The parallel licensing arrangement in Mumbai did not arise out of a conscious policy decision, but through a series of litigations. Historically, Mumbai has had three major electricity companies: Reliance Infrastructure Limited (RInfra), BEST, owned and operated by Brihan Mumbai Municipal Corporation, and Tata Power Company Ltd. (TPC).[35] While the former two acted as traditional distribution licensees, TPC was initially a bulk supplier.[36] By 1997, TPC was supplying power to a few large consumers in areas where RInfra held the license to supply. TPC's right to supply to these consumers was challenged by RInfra and in a landmark judgement in 2008, the Supreme Court upheld TPC's right. The Court even suggested that TPC can supply power by using RInfra's network (Supreme Court, 2008). To comply, the MERC, through an interim order, formalised the mechanism to allow consumers to change their supplier while continuing to use the network of the existing service provider (MERC, 2009). Thus, in an arrangement similar to open access, such consumers paid wheeling charges for use of the network to one licensee, and paid the other licensee for power supply. MERC, in the interim order argued that such an arrangement would be economical as it would avoid duplication of the network in a congested city like Mumbai. As on December 2016, there is no final order on this matter. Later on, the TPC was allowed to supply in BEST's distribution area as well (MERC, 2010), and despite appeals by BEST, this decision was upheld by the Supreme Court (Supreme Court, 2014c).

This unique arrangement has not resulted in competition, nor has it increased efficiency. In fact, the cost-plus tariff determination approach and lack of regulatory

34. In Uttar Pradesh, the state run Pashchim Vidyut Vitaran Nigam Limited (PVVNL) applied for a parallel license in the area of supply of Noida Power Company Limited in 2009, but this has not been operationalised yet.

35. RInfra and TPC have generation, transmission and distribution businesses being handled by subsidiaries. For example, the distribution business is handled by RInfra-Distribution and TPC-Distribution respectively. For simplicity, all the companies owned by Reliance Infrastructure Limited and Tata Power Company Ltd. are collectively referred to as RInfra and TPC respectively.

36. A company which sells power to other distribution companies and only large consumers with significant demand.

oversight has resulted in passing on of costs borne out of DISCOM inefficiency onto consumer tariffs. In spite of various directions from MERC to sign long-term power procurement contracts, RInfra relied on expensive short-term arrangements to meet demand. The share of short-term power purchase increased rapidly from 5% in 2006–07 to 38% of the total power requirement in 2010–11. In 2010–11, short-term power purchase accounted for more than half the power purchase expenses of RInfra. It was only in 2012–13 that RInfra signed a long-term power purchase agreement but on a cost-plus basis with its sister concern Vidarbha Industries Power Limited (VIPL) whose tariffs shot up by 60% by 2014–15 (PEG, 2016b). Consumer bill savings in 2011–12 from switching to TPC (from RInfra) were in the range of 13% to 41%. Due to this, by June 2011, about 1.6 lakh consumers, especially large industrial consumers, migrated from RInfra to TPC (Sreekumar & Josey, 2012). RInfra is not the only DISCOM with inefficient power procurement practices. The cost per unit of power from TPC's generating units which also supplies to BEST shot up from ₹ 3.73/unit in 2007–08 to ₹ 4.81/unit in 2014–15. TPC too has been reluctant to sign long-term contracts for power with its dependence on short-term power purchase in the same period increasing from 5% of the total power procured to 31% (PEG, 2016a). Therefore, today the average tariffs of all DISCOMs are expensive and changing the supplier does not result in consumer benefits.

Rampant increase in costs coupled with loss of revenue for RInfra due to sales migration resulted in the creation of regulatory assets[37] for recovery of losses from consumers. This increased from ₹ 25 crores in 2006–07 to ₹ 3377 crores in 2011–12. With sales migration reducing the consumer base to recover such losses, MERC imposed a cross-subsidy surcharge (CSS) as well as a charge to recover the imposed regulatory asset on consumers migrating from RInfra to TPC (MERC, 2011). This decision was challenged by the TPC and is pending before the Supreme Court as of December 2016.

Given regulatory approval of all costs and limited public reaction to high tariffs, DISCOMs clearly have no incentive to compete and increase efficiency. Ambiguity and delay in regulatory decisions also contributes to price uncertainty and increased litigation. Without a final order to operationalise parallel licensing in Mumbai, it is still unclear if TPC has to lay down its own network or use RInfra's or can do both.[38]

37. In order to recover costs without subjecting consumers to tariff shocks, SERCs create regulatory assets using which recovery of past expenses can happen over a number of years. During the course of this time, utilities can also claim carrying cost at a predetermined interest rate on pending amounts.

38. Meanwhile, TPC had been laying down its network and claiming capital expenditure for it (PEG, 2016a).

Additionally, the decision to impose CSS and the regulatory asset charge was taken two years after parallel licensing was allowed. By this time, 1.54 lakh consumers had already opted for changeover[39], and applicability of these charges significantly eroded the perceived benefits of this move for many. With the limited space availability in Mumbai, consumers cannot migrate to rooftop solar options despite it being a financially lucrative option. Over time, large consumers are moving out of Mumbai to avail open access, and this shift is increasing the burden on small consumers who are stuck in a low-lying equilibrium of inefficiency and high costs which the DISCOMs in Mumbai have settled into.

5.5 Short-term markets

The short-term power market in India is significant, with inter-state short term trades with a duration of less than one year alone accounting for 10% of the total power traded in India (CERC, 2015b). Short-term power purchase by DISCOMs and its implications on power procurement cost has been covered in Section 5.3. Short-term transactions can also happen between open access, captive consumers and generators directly through contracts. The Electricity Act, 2003 also allows for trading licensees which can facilitate power trades between generators and consumers, and DISCOMs. Some trading licensees like Power Exchange India Limited (PXIL) and India Energy Exchange (IEX) function as exchanges where power is sold at market determined prices based on bids. A trade not facilitated by the exchanges is called a bilateral trade. Bilateral trades are carried out by trading licensees for a regulated trading margin. Such traders also carry out short-term bidding for the DISCOMs and interested generators on the DEEP platform. This section will focus on the operations of traders and power exchanges in broadening and deepening short-term markets.

Inter-state traders including IEX and PXIL are regulated by the CERC and licensees conducting only intra-state trades are regulated by the respective SERCs. SERCs do not monitor or publish data on intra-state bilateral trades even though the volumes are significant. About 53% of open access consumers in Maharashtra procure power from intra-state bilateral traders. It is difficult to determine DISCOMs' dependence on intra-state bilateral traders due to paucity of data. Lack

39. Consumers who take supply from one distribution company though its distribution network, while switching to another distribution company for supply of electricity, continue to be connected to the distribution network of the first distribution company.

of information also makes it difficult to understand market dynamics and is a serious blind spot for policy makers and regulators, as there is no data on prices, volumes, market concentration, trading margins levied, and composition of buyers and sellers in intra-state markets. Lack of such crucial information can also have serious implications when trade volumes grow.

The CERC regularly monitors and reports trade trends for inter-state bilateral market and exchanges in its market monitoring report. However, it reports only transactions via trading licensees and power exchanges for durations less than one year. It does not cover contracts having duration between one and three years which trading licensees can enter into. The CERC also monitors any intra-state trade undertaken by inter-state trading licensees. Analysis of this limited information points to curious trends which are discussed below.

5.5.1 Market concentration and activity

As of September 2015, the CERC regulates 43 inter-state licensees. More than 70% of the power traded in inter-state bilateral markets happens through six trading licensees indicating significant market concentration (CERC, 2015e). Four of these trading licensees are subsidiaries of companies who own other businesses in the sector such as distribution companies, power generators and transmission licenses. The largest market player is the state owned PTC India Limited, which is responsible for a third of the total bilateral trades. Several CERC trading licensees do not register any trades despite possessing trading licenses for a considerable time period. As of 2014, 24 trading licenses were either revoked by CERC or surrendered by the companies over the years.

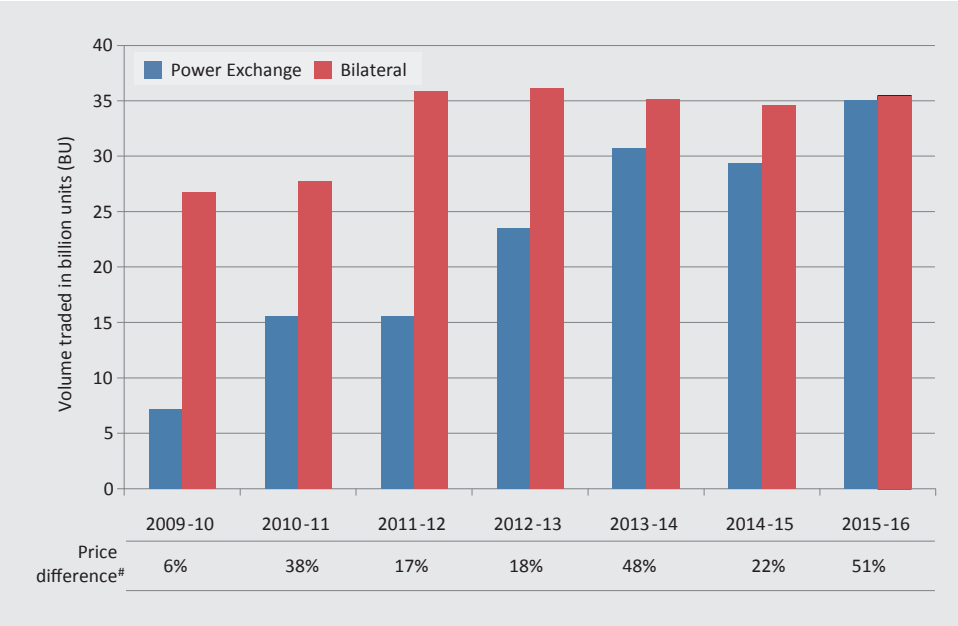
5.5.2 Duration of contracts

Most of the trades on the power exchanges happen on a day-ahead basis for a period less than 24 hours. Both power exchanges have market instruments for purchase of up to a week. However, the volume of trades using these instruments is abysmal amounting to only 0.2% of volumes traded on a day-ahead basis. Longer term instruments can protect generators and consumers from price volatility. It is a major step forward in deepening markets. Contracts for longer durations in transparent automated platforms like power exchanges can attract more consumers than trading licensees. However, IEX and PXIL are unable to introduce month-long or year-long instruments due to a jurisdictional issue between the Forward Markets Commission (FMC) and the CERC. The matter has been pending before the Supreme Court since 2011.

5.5.3 Price and volumes traded

Figure 5.6 shows that despite having larger volumes, power purchased through bilateral contracts is more expensive than power purchased through exchanges.

Figure 5.6: Trends in volume and price of inter-state sales through power exchanges and bilateral contracts



Proportion by which bilateral purchase is more expensive than power purchase through exchanges on an average basis.[40]

Source: CERC Market Monitoring Committee Reports (CERC, 2015b).

The price differential shown in the table above could be lower as bilateral contracts could also account for transmission costs. In spite of this, it is quite likely that exchange prices are lower. Figure 5.6 also shows a steady increase in transactions via power exchanges. This can be attributed to the steady growth in open access consumers, who accounted for about 60% of the total trade in exchanges in 2015-16 (CERC, 2016a). Most of these consumers are located in Tamil Nadu, Andhra Pradesh, Gujarat, Punjab, Haryana and Rajasthan. Even though DISCOMs are still the predominant buyers in power exchanges, given the volumes transacted, it is clear that DISCOMs prefer bilateral contracts despite higher prices. With paucity

40. The power exchange prices considered do not include increased prices due to transmission congestion in a particular area which can increase power exchange prices by about 2-3% (IEX, 2016).

of information, it is difficult to ascertain the reason for this choice. It can be argued that certainty in price and volume could be one reason. As described earlier, power exchanges do not have market instruments for durations longer than a week. But this is belied by the fact that 99% of inter-state bilateral trades in 2014–15 were of durations of less than one week (CERC, 2015b).[41] This preference could also be because power exchanges require advance/prompt payment for power procured, but with bilateral traders, DISCOMs can negotiate more flexible payment terms. There have also been contentions that DISCOMs have high-cost contracts with subsidiary/related companies, or prefer bilateral trades instead of anonymous trades due to other vested interests (Kasturi, 2013). Given the lack of transparency in bilateral trade, especially intra-state bilateral trade, it is hard to hold DISCOMs accountable in this crucial area.

5.5.4 Deviation and Settlement Mechanism (DSM)

The Deviation and Settlement Mechanism (DSM), notified by the CERC in 2014, is a commercial arrangement with incentives and penalties to maintain grid discipline and grid security. This replaces the Unscheduled Interchange (UI) mechanism, which was introduced along with the Indian Electricity Grid Code (IEGC) in 2000. DSM is an improvement on the UI mechanism in terms of maintaining the discipline of grid operation. The UI mechanism had varying energy charges based on the system frequency. Generators are penalised when they inject power during high frequency, and bulk buyers are penalised when they draw power during low frequency. Even though UI was intended to be a commercial 'carrot and stick' mechanism to prompt all actors to maintain grid frequency within limits, once the electricity market started, UI was also used as a real time market mechanism for trading electricity. There was criticism of its effectiveness to ensure grid security, especially after the 2012 grid failures. These discussions led to the DSM regulations of CERC in 2014. DSM regulations discourage the use of UI as a market mechanism, further tightens the frequency deviation band to 50.05 – 49.7 Hz, and suggests limits for the volume of unscheduled interchange. All generators and buyers connected to the Inter-State Transmission System, using short, medium or long-term open access, are expected to submit day-ahead schedule for power generation and withdrawal in 15 minute intervals. Actual deviation from this schedule, especially when it endangers grid security, is sought to be minimised through the DSM.

41. Between August 2014 and August 2015.

Almost a decade after the introduction of short-term market mechanisms, the market remains fragmented and with inefficient price discovery due to information asymmetries. Additionally, there is significant market concentration in the bilateral segment with few players, and with prominent trading licensees having sister concerns which are DISCOMs, generators and transmission licensees. Many major big ticket changes introduced in the Electricity Act, 2003 such as allowing open access and delicensing of generation were initiated with the implicit understanding that short-term markets will function efficiently and facilitate the necessary changes. The expected changes included enabling effective choice for large open access and captive consumers, efficient real time adjustment of power, and ensuring efficient power procurement for DISCOMs. As of 2016, major reforms such as mainstreaming open access operations and real-time balancing for renewable energy are still pinned on functioning short-term markets. Effective action to make short-term markets transparent, larger, more integrated and efficient is therefore critical.

5.6 Financial health of distribution companies

Distribution companies have often been characterised as the weakest link in the electricity value chain due to their debilitating, long standing financial issues. Therefore, one of the prime motivations to reform the distribution sector in the 1990s was to restore its financial health and viability. This section discusses the major causes and catalysts for the persistence and ballooning of accumulated losses. It also examines the impact of programmes, initiatives as well as bailouts towards reducing the extent of losses or restructuring existing debt. There have been three major bailouts in the past which will be discussed in this section. Table 5.9 provides a brief overview.

Table 5.9: Scale and significance of past electricity sector bailout schemes

Period	Name of scheme	Scheme magnitude	Comparable to
2001	2001 scheme for repayment of SEB Dues	₹ 41,473 crores	Central and state planned expenditure on social services in 2001–02
2012	Financial Restructuring Plan (FRP)	About ₹ 1.19 lakh crores	Cumulative expenditure on wages in the MNREGA scheme (2006–14)
2015	Ujwal Discom Assurance Yojana (UDAY)	About ₹ 2.01 lakh crores as on July 2016	Comparable to India's defence spending for 2015–16

Source: (Planning Commission, 2001; MoP, 2012a; MoP, 2015c).

Before analysing the bailouts, in the following sections, we discuss some of the major contributors to the DISCOMs' financial predicament, namely high technical and commercial losses, lack of regular tariff revision, issues with power procurement planning, delays in subsidy payments, dependence of DISCOMs on lending from banks, and the lack of regulatory accountability.

5.6.1 High Aggregate Technical and Commercial (AT&C) losses

High AT&C losses can be attributed to technical losses due to low investment in network and commercial losses due to poor metering, billing and theft. Inadequate revenue receipts, especially in rural areas, resulted in selective load shedding and abysmal investments. With no improvement in service quality, revenue collection from disgruntled consumers reduced. The resulting impasse needed a breakthrough to restore the financial viability of DISCOMs and has been the focus of major programmes, investments and conditional grants. Efforts were also taken to franchise and even privatise distribution in high loss pockets in cities as described earlier.

Estimation of losses is ideally done on the basis of data from energy meters at different locations — consumer, transformers and 11 kV feeders. However, agricultural consumers in almost all states, and domestic and commercial consumers in a few states like Uttar Pradesh and Bihar, continue to be unmetered. Additionally, feeders and distribution transformers in many states also remain unmetered. Even if they are metered, most are not equipped with automatic meter readers which can mitigate the need for manual intervention in meter reading. Even if agricultural consumers are not metered, metering of agricultural feeders will provide a reasonable estimate of agricultural consumption and consequently losses in the distribution network. The feeder separation programme which is being implemented in many states can enable agricultural feeder metering. Over the years, there has been a significant reduction in the reported AT&C losses at the national level, which fell from 36.64% in 2002–03 to 25.38% in 2012–13. The veracity of these claims can be questioned given the dismal state of infrastructure metering and consumer metering, and absence of publicly available 11 kV feeder level data.

Loss reduction has been considered as a critical element for the success of reform efforts. In fact, the 11th Plan approach paper cited high AT&C losses as one of the reasons for the limited success in attracting private investment in generation capacity (Planning Commision, 2006). Though necessary, metering and revenue recovery are considered politically difficult steps by many state governments.

In major interventions to address AT&C losses, there appears to be a mismatch between the central government's objectives and the state government's interests. This is discussed in the next section.

5.6.2 Major loss reduction programmes

Since 2000, India has seen four central sector programmes to ensure AT&C loss reduction. All these programmes had an urban focus and aimed at loss reduction through large investments in network augmentation and system upgradation. A brief description of these programmes is provided in Table 5.10.

Table 5.10: Aggregate Technical & Commercial loss reductions programmes

Name of Programme	Accelerated Power Development Programme (APDP)	Accelerated Power Development and Reforms Programme (APDRP)	Restructured Accelerated Power Development and Reforms Programme (R-APDRP)	Integrated Power Development Scheme (IPDS)
Period	2000–2002	2002–2008	2008–2014	2014–present
Eligible areas	63 distribution circles	Selected urban circles	Urban areas with population > 30,000	All urban areas
Budget Allocation[42] (₹ Cr.)	1,042	6,991	28,424	25,354
Funds released (₹ Cr.)	547	3,426	8,175	1,422 (Dec. 2016)

Source: (MoP, 2002; MoP, 2014a; Standing Committee on Energy, 2005; MoP, 2016a; CAG, 2016; CAG, 2007).

The works planned under each programme were quite similar which could be because funds allocated in earlier programmes were not released or spent as planned. The difference is most acute for the ambitious R-APDRP where the project cost sanctioned is massive[43], but the funds released were abysmal. There

42. Budget allocation refers to the grants provided by the Central Government for the project. The outlay itself which includes loans is much higher.

43. As per the Cabinet Committee on Economic Affairs (CCEA) approval for R-APDRP scheme dated 30 July 2008, an outlay of ₹ 51,577 crores had been provided during the XI Plan period for the Scheme. This is comparable to the additional central assistance released for the Jawaharlal Nehru National Urban Renewal Mission (JNNURM) up to March 2011.

were several issues with the design and implementation of such schemes which were inherited by successor schemes as well. The funds disbursal process was complex, plans were overambitious, and the implementation was fraught with delays and cost overruns. Moreover, the cooperation of the state government and commitment from the DISCOM, fundamental to the programme's success, was absent. Despite the large allocation of funds, there has been no public review (even by regulatory commissions) of any of these programmes. As the latest IPDS has a similar programme design (albeit with a more robust monitoring framework and high levels of transparency), it is likely that co-operation from states will be low, and the trend of large allocations but low investments may continue.

Targeted efforts towards metering as well as AT&C loss reduction has been the foremost performance related condition put forth for distressed DISCOMs to abide by in case they want to avail assistance under bailout packages. This is also true for the current bailout scheme, the Ujwal Discom Assurance Yojana (UDAY), under which there are plans to monitor progress in loss reduction even at the division level and targets for distribution transformer metering. Experience from past programmes suggests that loss reduction will remain elusive unless there is a commitment from state level actors, periodic monitoring and conditional assistance provided by the centre.

5.6.3 Increasing costs, lack of regular tariff increase

One of the reasons for high financial losses identified by policy makers is that in many states, tariffs do not increase commensurate to increase in costs. Since the 1990s, on an average, revenue recovered by DISCOMs has been 30% lower than the cost incurred (Planning Commission, 2014a; Planning Commission, 2002). By 2011–12, this meant that nationally, ₹ 1.15 lakh crores of costs incurred could not be recovered through tariffs (Planning Commission, 2014a). Between 2009–10 and 2014–15 the average cost per unit of sales shot up from ₹ 4.9 to the unsustainably high level of ₹ 6.6 (PFC, 2013; PFC, 2015; PFC, 2016b). Even with increasing costs, ERCs of many states did not revise tariffs on an annual basis. Some of these states, namely Rajasthan, Uttar Pradesh and Tamil Nadu, account for more than 70% of accumulated distribution sector financial losses.

SERCs often blamed the DISCOMs for irregularity in tariff revision as they were not submitting tariff revision proposals on time. The Shunglu Committee exposed the disingenuousness of this argument by reminding the ERCs that they can exercise their suo-motu powers to ensure tariff revision (Planning Commission, 2011).

Subsequently, acting based on a letter written by the Ministry of Power (MoP), the Appellate Tribunal for Electricity (ATE) directed all ERCs to initiate suo-motu proceedings for tariff determination in the event of any delay in submission of tariff revision (ATE, 2011). Many SERCs[44] complied with this order on paper by issuing tariff orders without any tariff revision. This is not surprising as the directive itself was issued without considering economic and political realities and the already high electricity tariffs. Since 2011, many states like Rajasthan and Tamil Nadu have stopped complying with the directive. Many SERCs use the fuel adjustment charge (also called fuel and power purchase cost adjustment charge) which is levied over and above tariffs on a quarterly basis to compensate the DISCOM for expenses incurred above approved revenue recovery as a mechanism to bypass the political deadlock of increasing tariffs. Fuel adjustment is often a misnomer as these charges are also used to recover fixed costs. This recovery is approved without the same regulatory or public scrutiny as for tariffs during the tariff determination process.[45] All signatory states under the UDAY scheme have to ensure quarterly determination of such fuel adjustments costs.

Regular tariff increase alone will not help DISCOMs achieve financial viability. Tariff increase without efficiency improvements will result in spiralling costs, increased payment defaults, and theft on the one hand, and sales migration of large consumers on the other. Both outcomes further deteriorate the financial position of DISCOMs. With the current tariff design, sales migration of high paying consumers would also imply reduction in cross-subsidy. State governments and DISCOMs are not prepared to handle the difficult transition to a design with reduced cross-subsidy. For DISCOMs with extremely high cost of supply, a large number of small consumers and limited funds with the state government, the reduction of cross-subsidy could deny access to electricity for many.[46] That being said, most states are also not prepared to take the hard road of reducing costs and increasing efficiency to reduce losses.

By 2015, there was a recognition among policy makers that tariff increase alone cannot address the accumulating losses of DISCOMs. UDAY, launched four years after the ATE directive, was designed keeping in mind that tariff increase is not

44. For example, the SERCs of Madhya Pradesh, Gujarat, Bihar, Himachal Pradesh, Delhi, and West Bengal in various years.

45. To further depoliticise tariff increase, Gujarat approved a base Fuel Adjustment Charge (FAC) (₹ 1.20 per unit for the year 2016-17) in the tariff order itself, which is not projected as a tariff increase but an additional cost.

46. In states such as Uttar Pradesh, Jharkhand, Rajasthan and Bihar.

the silver bullet to the intractable problem of DISCOM finances. Table 5.11 from a Ministry of Power publication for the UDAY scheme showing the tariff hikes approved in states with tariff increases higher than the national average, illustrates this point.

Table 5.11: Average tariff increase from FY 11 to FY 16 in a few states

State	Average tariff increase[47]
Kerala	16%
Delhi	14%
Andhra Pradesh	13%
Tamil Nadu	12%
Chhattisgarh	11%
Haryana	10%
Rajasthan	10%
Bihar	9%
Uttar Pradesh	9%
Odisha	9%
Average rate of inflation[48]	8%

Source: Presentation by the Ministry of Power on UDAY (MoP, 2015c).

It is quite clear that several of the states such as Uttar Pradesh, Tamil Nadu, Bihar, Rajasthan, Haryana and Delhi have had tariff hikes which are higher than the national average and are struggling under significant financial losses, even though the rate of tariff increase was higher than inflation. Though UDAY has several conditions and targets for performance improvements, there needs to be commitment from the states and regulators towards cost reduction.

5.6.4 Lackadaisical approach to power procurement planning

Besides the impacts on costs due to poor planning and issues with power purchase contract management, power procurement can also contribute to the indebtedness of the DISCOM. In 2001, SEBs around the country owed central public sector generating companies and coal companies more than ₹ 43,000 crores in liabilities (Planning Commission, 2001). The bailout scheme rolled out as per the report of the Ahluwalia Committee was to pay these creditors, mainly central sector power generating companies. As a consequence of the bailout,

47. Few states which have had significant tariff hikes recently, had not revised tariff for many years earlier.

48. Based on consumer price index for industrial workers.

strict payment conditions[49] were introduced and defaults in payment by DISCOMs to private and central sector generating companies became less frequent. Instead of defaulting on payments to private and central sector generators, DISCOMs began financing power purchase with short term borrowings at high interest rates from banks. This also implied that payments to state generating companies were often grossly delayed.

Despite the severe impacts on costs, no serious efforts have been taken by state-level actors such as SERCs, DISCOMs or the state government to rein in increasing power purchase costs. The central government also did not play a proactive role by ushering in reforms and efficiency in the coal sector, or by conducting a serious and effective benchmarking exercise for the capital cost of generating units.In order to change the practices of DISCOMs and restore profitability, bailout schemes were provided conditional to the DISCOM agreeing to performance milestones. In the context of power procurement, many conditions were stated. These are listed in Table 5.12.

Table 5.12: Conditions related to power procurement across bailout schemes

Scheme	Power procurement related condition or provision in bailout schemes
SEB Bailout Scheme (2001)	Regular and timely payments to CPSUs for power generation.
Financial Restructuring Plan (FRP), (2012)	Future power procurement through competitive bidding in a time bound manner
	State government to consider review of state owned generating assets
	Fuel Adjustment Costs to be allowed by SERCs to offset increase in power purchase costs.
	Progressive reduction of short term power purchase
Ujwal Discom Assurance Yojana (UDAY), (2015)	Future power procurement through competitive bidding in a time bound manner
	Review of state owned generating companies
	Increased efficiency in coal sector with increase in production, rationalisation of coal linkages, third party sampling
	Quarterly Fuel Adjustment Costs to be allowed by SERCs to offset increase in power purchase costs.

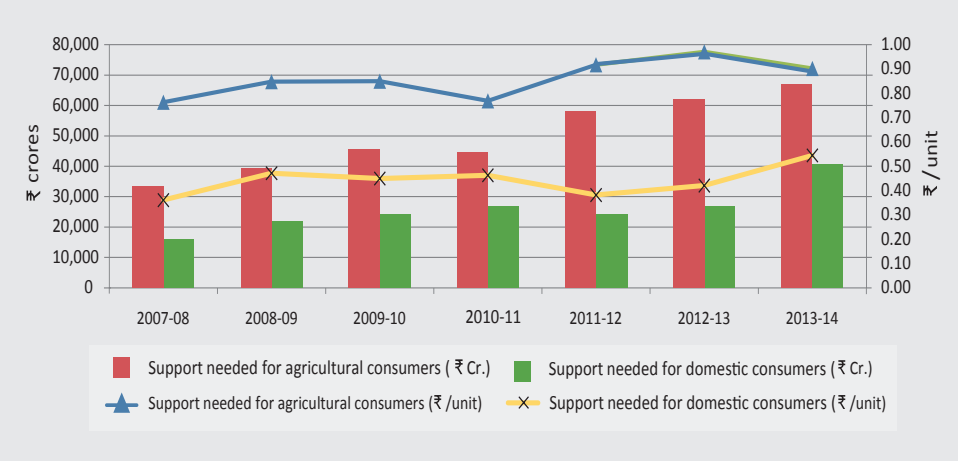
Source: (Planning Commission, 2001; MoP, 2012a; MoP, 2015c).

49. These included introducing security mechanisms, penal interest in case of default and reduction in power supply (Planning Commission, 2001).

5.6.5 Unfunded mandate: pending subsidy payments and support by state governments.

Given the strong links between sustained electricity use and development, electricity consumption by certain consumer categories needs to be supported. Such support is provided through state government subsidies or cross-subsidies. Agriculture consumers and households are predominant recipients of such support. Figure 5.7 shows how much support was required to cover the gap between tariffs paid by these consumers and the expenditure incurred to supply to such consumers. This support was provided either through subsidies and cross-subsidies or remained uncovered as DISCOM losses.

Figure 5.7: Subsidy and cross-subsidy on an all India basis (2008-2014)



Source: (Planning Commission, 2014a).

Agriculture has been the prime recipient of support, but the subsidy support provided to domestic consumers is growing rapidly. This could be due to increased electrification in the recent past which has also increased the number of newly electrified, subsidised BPL households. This steady increase in the last couple of years could be due to the increasing trend in many states such as Delhi, Tamil Nadu, Haryana and Maharashtra to widen the subsidy net to include domestic and other consumers. In 2014–15, about ₹ 77,660 crores[50] was spent on power subsidies by state governments in India (RBI, 2015b). This is about 60 times more than the gross budgetary support provided by the Ministry of Power in the same

50. This could include grants to generation and transmission companies as well.

year. The dependence of DISCOMs on subsidies to meet the expenditure needs is quite substantial, with subsidies meeting 15% of the revenue requirement of most DISCOMs (Planning Commission, 2014a). The delayed payment of subsidies can impact cash flow considerations of DISCOMs, and can increase their dependence on short-term loans from banks.[51] Despite the mandate under Section 65[52] of the E-Act for making subsidy payments at the start of the year, most states have not been making these payments on time.

After unbundling, the liabilities of the erstwhile SEBs were to be transferred to the state government as part of the transfer scheme[53]. However, this process has not been completed in many states. Some DISCOMs, like TANGEDCO in Tamil Nadu, are stuck with over ₹ 17,000 crores as liabilities of the erstwhile board (TNERC, 2013). Till date, only Gujarat seems to have completed the transfer scheme which could have contributed to the healthy financial position of its DISCOMs (GUVNL, 2006). Regulators have also failed to hold the governments accountable for promised subsidy payments and completion of the transfer scheme.

5.6.6 Dependence of DISCOMs on public sector banks

As mentioned earlier, over the years, the DISCOMs' creditors have changed from central public sector units to nationalised banks. This change is critical to note as it has impacts even on the viability of the banking sector. 60% of the gross outstanding bank credit for the infrastructure sector in 2014–15 accrued to power sector institutions[54], which has been increasing by 24% annually since 2008–09 (RBI, 2015a). Therefore, increasing short-term borrowings by cash strapped, defaulting distribution companies can crowd out priority infrastructure investment.

For the DISCOMs, this availability of finance with reduced accountability is dangerous, since there is no incentive to improve financial health. DISCOMs are able to borrow from banks which readily provide loans without exercising due diligence. This 'open tap' to finance their unsustainable operations helps them

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51. In order to illustrate, if we assume that 40% of the subsidy amount was not paid on an all-India basis, DISCOMs collectively would have to incur interest payments of about ₹ 3,500 crores annually.

52. As per Section 65 of the Electricity Act any subsidy granted to a consumer or a class of consumers in tariffs shall be paid in advance by government.

53. After unbundling of the State Electricity Boards, state governments were to launch schemes to settle claims and outstanding liabilities of the board and transfer assets and personnel to the newly formed distribution, transmission and generation companies.

54. This includes generation companies and transmission companies.

avert compliance to accountability measures and respond to pressures to increase efficiency. It also aids them to postpone dealing with financial issues until the extent of liabilities has ballooned to critical levels, necessitating a bailout. Bailout programmes have also provided banks with an escape route from facing the natural consequences of recklessly advancing loans to these companies. In fact, the prevalence of this practice makes one suspect if reckless lending is in anticipation of future bailouts. Within the ambit of the power sector, there are no mechanisms to hold banks and other lending agencies accountable for their practices. This is unlike the earlier case where the creditors were power sector institutions. ERCs do not effectively monitor borrowing from banks during the tariff determination process. In fact, the working capital approved in tariff processes is far removed from reality as it is based on a prescribed formula rather than the borrowing practices of DISCOMs. The RBI too has failed in its role as a regulator to keep lending by public sector banks in check.

Within a decade after the first bailout in 2001, the liabilities sky-rocketed and the central government announced the Financial Restructuring Plan (FRP) scheme in 2012 to deal with the accumulated liabilities. One of the conditions of the FRP scheme was that DISCOMs cannot borrow from banks to meet their day to day requirements. Two years after FRP, DISCOMs accumulated ₹ 63,000 crores of additional short-term liabilities. This clearly shows that there was no committed effort to follow or enforce this condition. In both UDAY and FRP schemes, creditors are not held accountable for their actions as they do not pay the price for their poor judgement, and recover more than their principal amounts. As no alternate arrangement for financing present operations was provided to the fragile DISCOMs during their transition to a financial turnaround, their continued dependence on banks is not surprising. UDAY also places a similar moratorium on borrowing from banks and caps the working capital requirement of DISCOMs at 25% of the revenue requirement. It is yet to be seen if DISCOMs will comply with these conditions or if there will be another bailout in the coming years.

5.6.7 Issues with regulatory oversight

This section details all processes and costs which contribute to accumulating losses as a direct consequence of regulatory failure.

Lack of regular truing-up of costs

Besides increasing tariffs, the tariff determination process is also crucial to hold the DISCOM publically accountable for its performance, and decide the prudence

of incurred and projected expenditure of the DISCOM. The process of evaluating past performance and disallowing recovery from consumer tariffs for avoidable costs incurred is called true-up. Unlike the accounting term, regulatory true-ups are much more than verification of costs. Regular true-ups inform the stakeholders about the past performance as well as the financial predicament of DISCOMs. It can provide early warning signals for a financial crisis in the making. Unlike tariff determination, truing-up has not been a regular process before the commission. The ERC in Tamil Nadu has never completed a true-up for a full financial year, and ERCs in the states of Madhya Pradesh and Uttar Pradesh did not conduct the process at all till the introduction of FRP in 2012. Other ERCs are irregular, often skipping years and delaying it for particular years. Delays of true-ups have financial implications, as utilities claim payments incurred in the past years for recovery with a carrying cost. For example, when the Uttar Pradesh Electricity Regulatory Commission (UPERC) conducted its first ever true-up in 2012, it discovered that the utilities had a consolidated revenue gap of ₹ 14,368 crores from FY01 to FY08, for which it claimed a carrying cost of ₹ 11,352 crores. This carrying cost could have been avoided with regular true-ups (UPERC, 2013). The ATE also directed SERCs to ensure that an annual performance review with true-up of past expenses is conducted on a year to year basis[55] (ATE, 2011). Due to a significant push[56] from the central government, true-ups are slowly increasing in frequency across states. Lack of regular true-ups or performance accountability is clearly a regulatory failure.

Missed opportunities for cost reduction via implementation of multi-year tariff framework

In the same vein, the Multi-Year Tariff (MYT) framework was introduced to encourage good planning practices and ensure efficiency improvements by specifying performance trajectories so as to have better control and predictability with respect to costs, and hence the tariff. The framework also has provisions for sharing of certain risks between consumers and DISCOMs instead of passing on all risks and associated costs to consumers. Almost all states have notified regulations for implementing MYT, but no SERC has held DISCOMs accountable for performance with respect to approved performance trajectories. An MYT process which plans for a three to five year time horizon would have been ideal

55. This direction was given in the same order where ATE directed SERCs to conduct regular tariff determination processes using their suo-motu powers if need be.

56. UDAY and FRP programmes also insisted on true ups.

for medium-term planning and for accounting for contingencies which will have significant impact on cost and operations. Sadly, it is implemented as a matter of clerical compliance with very little continuity in processes and lack of accountability to plans.

Creation of regulatory assets

Regulatory assets are created to defer recovery of revenue gaps and losses from consumers so as to mitigate the tariff impact. As they are significant and come with a carrying cost, they also contribute to the growth of losses. Regulatory assets would have worked for manageable revenue gaps, when the recovery is time bound and a one-time exercise. However, DISCOMs usually have rapidly increasing revenue gaps on which the carrying cost accumulates. The creation of regulatory assets was used by the DISCOMs and the regulator to postpone tackling the issue while the crisis burgeoned. The 2016 amendment to the National Tariff Policy states that no regulatory assets should be created unless the circumstances are exceptional, and also calls for a time-bound recovery of existing regulatory assets (MoP, 2016e).

Clearly, regulatory failure can be considered a major contributor to the financial crisis facing DISCOMs. Even though they may not be responsible, the growing revenue gaps, regulatory inaction in holding DISCOMs accountable for past performance via true-ups, ambiguity in regulatory decisions leading to payments arising out of litigation, lack of emphasis on planning and implementation of the MYT process, acceptance of regulatory assets and associated carrying costs contributed to the issue. Even though ERCs are supposed to have consumer interest and long-term sector interest in mind, no SERC has conducted a public review (with the involvement of the state government) to study the finances of DISCOMs with a view to chalk out an action plan for the near future. SERCs could have played a major role in controlling the crisis if not preventing it.

5.6.8 Lack of analysis and insights into crippling issues

In spite of regular bailouts and the financial viability of DISCOMs being recognised as a key challenge, there has been no assessment, at the central or the state level, of the actual quantum of losses and the contribution of each cause to the accumulating losses. Without this assessment on a periodic basis, it is difficult to take action before losses reach unsustainable levels.

The 2011 report under the chairmanship of V.K. Shunglu is perhaps the only effort in recent times to analyse the financial predicament of the distribution

companies. Among other contributions, the report presented a comprehensive review of accounts which highlighted the poor quality of financial data (Planning Commission, 2011). Surprisingly, the various bailout schemes do not present any analysis of the extent of accumulated losses and outstanding liabilities of DISCOMs. The details of losses taken over in earlier schemes are also not available, making it difficult to ascertain impacts of the scheme. In effect, the true scale of the problem also remains ambiguous. To understand the rapid loss accumulation, data on the cause of the losses and the steps taken by the utility to continue functioning is crucial. Therefore, data on losses due to non-receipt of promised subsidy payments, recovery of regulatory assets and associated carrying costs would prove insightful. Further, statistics on the share of interest payments in the total liabilities, short-term liabilities as a proportion of total losses, and the quantum of outstanding payments to power sector agencies could point to the myopic strategies used by the DISCOM to finance current operations. Data on proportion of losses which are due to costs disallowed by the regulator is also insightful. More often than not, these costs arise out of inefficient practices of the distribution company such as failure to meet regulatory norms, poor metering, and continued purchase of high cost power. Possible financing of such costs via bailouts could show that regulatory checks are ineffective in holding the distribution companies' accountable. It could also imply that such costs, if not borne by the electricity consumer, will ultimately be borne by the tax payer, because government securities are used to finance bailouts.

5.6.9 Bailouts provided to Distribution Companies: UDAY and its predecessors

Since 2001 there have been three bailouts provided to distribution companies. All of these schemes including the present UDAY have been described earlier and are very similar in design. In each scheme, the state government takes over a major portion of the past liabilities by issuing long-term bonds. These bonds are bought by banks and other financial institutions. It is imperative that the state government takes over the debt, as the state owned DISCOM is its responsibility, and as it could have prevented escalation of debt. Additionally, unlike DISCOM bonds, there is a higher appetite and confidence in the market for state government bonds which have the sovereign's commitment to repayment. The previous two bailout schemes financed past liabilities and did not account for any mechanism to finance losses that DISCOMs will make in the transition period on their way to a financial turnaround. UDAY is different from past schemes as it plans for the state government to finance not just past liabilities but also losses incurred in the future. Future losses are to be taken over in a progressive manner in perpetuity.

If implemented, this will increase accountability of state governments to ensure efficiency improvements in the DISCOM. As of October 2016, 16 states have signed up for UDAY. This participation is also much higher than the FRP.

All three schemes were voluntary with participating state governments and DISCOMs agreeing to comply with conditions and meeting performance targets in a time-bound manner. Some of the conditions with respect to AT&C loss reduction, power procurement planning, and the moratorium on short-term lending have been discussed earlier in this section. Often, these conditions did not come with achievable milestones or support. Most of the provisions and conditions amount to platitudes without measurable outcomes, defined performance milestones, monitoring and cooperation from the states. However compliance in all schemes was to be monitored by the central government on a regular basis, and incentives or penalties were to be awarded based on performance.

The current UDAY scheme has similar conditions and ambitious timelines to the past two schemes, as it plans to eliminate revenue gaps by 2019 and reduce AT&C losses from unsustainably high levels to 15% with metering drives and measures to improve revenue collection. The condition of ensuring sustained tariff increase is another highlight of these schemes. The UDAY scheme has annual targets for tariff increase which are part of the Memorandum of Understanding (MoUs) drafted by the central government with various states. Table 5.13 highlights the committed increase.

Table 5.13: Committed annual tariff increase by DISCOMs and state governments as per UDAY

State	FY16	FY17	FY18	FY19	FY20
Uttar Pradesh	5.47%	5.75%	6.95%	6.80%	6.60%
Rajasthan	Not available	0%	10%	8%	0%
Punjab	2.74%	0%	5%	9%	3%
Bihar	2.40%	10%	15%	10%	10%
Jharkhand	3.75%	9.60%	9.60%	9.60%	9.60%

Source: MoUs signed by various states under UDAY (MoP, 2016b).

Given the fact that regulators have the mandate to decide tariffs based on costs incurred and performance of DISCOMs, it is not yet clear if tariffs determined in regulatory processes need to match this commitment.

Monitoring of past schemes was driven by the central government and was not made public, and thus the accountability for monitoring agencies was reduced. Interestingly, regulators, who have the mandate to ensure accountability of DISCOMs, are never part of the monitoring process. UDAY plans to monitor over 100 parameters on a regular basis, and it is hoped that it is more transparent than previous schemes.

Till date, there are no publicly available reviews of the previous schemes which report implementation status, compliance, penalties, funds allocated, and liabilities cleared. This is true for UDAY as well. Additionally, there has been no documentation of important lessons learnt, suggestions for mid-course correction or for design of similar schemes. Given the lack of information, it is possible that a major portion of the present losses were also part of past schemes which have continued to persist with mounting carrying costs. It is hoped that the measures suggested in UDAY unlike in previous schemes have an impact. The real test of UDAY will come in election years or drought years when the commitment of the state governments to financial viability is challenged. It is hoped that the sector will not see a successor to the UDAY scheme announced to tackle the same problem but of a higher magnitude.

Under UDAY, governments have assumed that operations will continue as usual, and have projected a tariff increase for the financial turnaround of DISCOMs. This projected increase itself has catapulted the rates in 2020 to levels higher than the current cost of renewable energy or power available in the market even after accounting for transmission constraints. This is shown in the Table 5.14.

Table 5.14: Average tariffs in 2020 as proposed under UDAY targets

States	Average tariff (₹ / unit)
Jharkhand	5.48
Rajasthan	8.01
Punjab	6.94
UP	6.69
Bihar	6.67

Source: MoUs signed under UDAY and various tariff orders.

As distribution costs are more or less stable, if it is assumed that it takes ₹ 2 per unit to supply power, the average power procurement rates corresponding to these increased tariffs would be in the range of ₹ 5.3 per unit to ₹ 6 per unit. Rooftop

solar prices are about ₹ 6-7 per unit (CERC, 2015e) with further reduction expected (See Section 4.4.2) and as of June 2016, short-term market prices vary between ₹ 2.9 per unit to ₹ 3.9 per unit[57] (CERC, 2016b). In this scenario, tariffs will not be competitive at such high procurement rates and DISCOMs will lose their market share to open access, captive or grid connected rooftop solar options. The central and state governments along with the DISCOM and regulator need to invest time and resources to deliberate possible options in the future to avoid the situation spiralling into a worse financial crisis.

The story of DISCOM losses is not just a story of persistent AT&C losses and lack of tariff increase, but also a story of poor accountability of DISCOM operations, financing of unsustainable practices by reckless lenders, regulatory failure in nipping the crisis in the bud, and divergence of central government objectives from those of the state. Instead of trying to address the root causes, bailouts were introduced to temporarily tackle the issue. UDAY has the added advantage of state governments taking over past and future liabilities. But whether it will ensure compliance to conditions and evince a commitment from state governments towards financial viability is still an open question.

5.7 Agriculture and rural access

The story of rural electrification has been one of ambitious commitments and slow progress. With two-thirds of the Indian population living in rural areas, rural household access and supply to agriculture are critical challenges for distribution. During the first few decades after independence, rural electrification efforts were driven by electrification of villages near towns, powering social amenities, and from the mid-1960s with the advent of the green revolution, agricultural pump set electrification. Universalisation of household access and grid connectivity of all villages were not the focus. There was significant progress in village electrification and pump set electrification, in the southern and western states, especially in regions where farmers wielded political power (Sankar, 2005) (Kale, 2014). Table 5.15 gives a snap shot of the progress in village electrification and pump set electrification from 1950.

57. Of course, these market prices could increase as well, but even assuming a 20% increase these prices would become ₹ 3.5 – ₹ 4.5 per unit.

Table 5.15: Progress of village electrification and pump set energisation in India since 1950

Year	Electrified villages	% electrified villages	Agriculture pump sets	Agriculture consumption MU	% Agriculture consumption
1950	3,061	0.5	21,000	162	3
1961	21,754	3.8	1,99,000	833	5
1974	1,56,729	27.0	24,26,000	6,310	11
1980	2,49,799	43.0	39,66,000	13,452	16
1990	4,70,838	81.0	83,08,000	44,056	23
2002	5,12,153	86.3	130,43,926	81,673	22
2012	5,56,633	93.2	181,78,136	1,40,960	18
2015	5,77,629	96.7	199,12,081	1,73,200	19

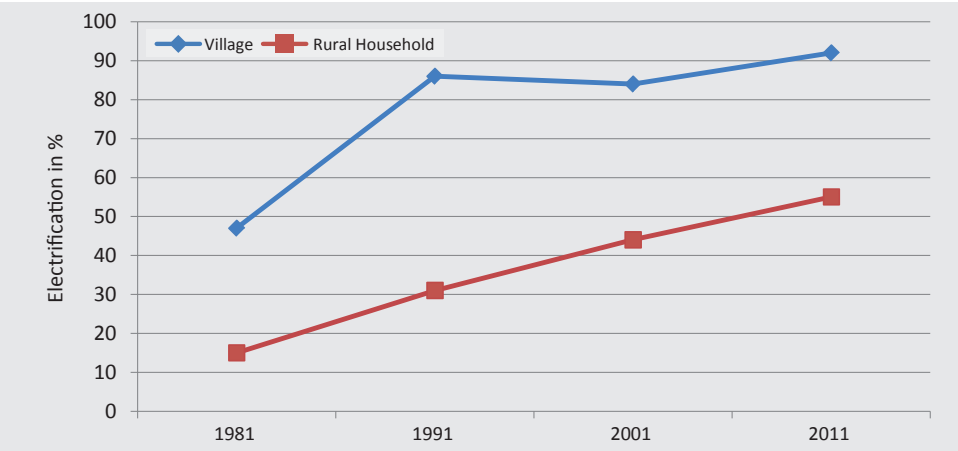
Source: (CEA, 2015a; World Bank, 1993b).

The pace of village electrification was high after the 1966-67 drought and advent of the green revolution, during the fourth five-year plan (1969-74). The pace slowed down during the first decade of reforms and picked up after the national rural electrification programme (RGGVY) began in 2005. As per government reports in December 2016, 99% of the villages have been electrified as per the current definition.[58] Pump set electrification also picked up during the fourth five-year plan and also after the 1980s, when metering was discontinued to introduce a tariff based on pump capacity. Consumption by agricultural consumers has been increasing all these years, but after the mid-1980s, the ratio of the agriculture consumption to total consumption has stabilised and even reduced, perhaps due to better estimates.

However, there was no specific focus on household electrification, as indicated by the low household electrification percentages in states with high village electrification, and also seen by the slow progress of rural household electrification compared to village electrification. Figure 5.8 gives the progress of village and rural household electrification in the period 1981–2011.

58. Till 1997, the definition of village electrification was: "A village is classified as electrified if electricity is being used within its revenue area for any purpose whatsoever". This definition was revised in 1997 to state that a village is considered electrified if electricity is used in residential localities. It was further improved in 2004 to include: a) The presence of a transformer and lines in the inhabited area including a Dalit basti; b) Public places like schools, the panchayat office, health centres, dispensaries, community centres etc. should be electrified; c) At least 10% households should be electrified (MoP, 2016g) . The 2006 Rural Electrification Policy had an additional condition that the gram panchayat shall certify that the village is electrified the first time and periodically every year. If it fails to do so, the state government may verify the status (clause 5.2 of Rural Electrification Policy 2006 (MoP, 2006b). It is not clear if this condition is being strictly implemented.

Figure 5.8: Progress of village and household electrification in India (1981-2011)



Source: (Sreekumar, Josey, Chitnis, & Dixit, 2013).

The pace of rural electrification slowed down after the reforms, and the rural electrification departments in many SEBs were neglected or even removed.[59] The reform measures were designed to improve the efficiency and financial health of the DISCOMs, and the expectation perhaps was that improvements in access will automatically follow. As there was always demand for electricity, policy makers perhaps expected that once the financial health of the DISCOMs improves, they would focus on rural electrification. After a few years of reforms, this did not happen and it was felt that an explicit focus on rural electrification is needed. After the first United Progressive Alliance (UPA) government assumed office in 2004, a national rural electrification programme was launched, the Rural Electrification Policy was announced, and the Electricity Act was amended to make rural electrification the joint responsibility of central and state governments.

Rural electrification has been high on the agenda of political promise since independence. Table 5.16 indicates the commitments and shifting timelines from the time of independence. It can be seen that targets were not kept, especially on household electrification. It is also obvious that the government did not back up the ambitious recommendations with required resource allocation and political support.

59. The 2001 Kanungo committee report on Odisha reforms states: "Rural electrification seems to have unintentionally become the worst casualty of the reform process... When OSEB was restructured and DISTCOs were privatised, the rural electrification wing of OSEB got disbanded and the focus on rural electrification disappeared, though the programme was not given up. It was apparently left to the DISTCOs to carry on with whatever schemes were in the pipeline. Since the activity is commercially unattractive, the DISTCOs are obviously not very enthusiastic about rural electrification, despite assurance of 100% capital subsidy by the State." (page 44)

Table 5.16: Shifting rural electrification commitments

Milestone	Commitment	Target year
Electricity Supply Act 1948	Benefits of electricity are to be extended to semi-urban and rural areas	Target not given. Village Electrification (VE) status in 1950: 0.5%
Conference of Chairman of SEBs (1976)	100% VE	1995
Rajadhyaksha Committee Report (1980)	100% VE, efforts for rural load development beyond agriculture pump sets	1995
	100% Household Electrification (HHE)	2000
National Development Council - Sharad Pawar Committee (1994)	100% HHE, supply available on demand for productive uses	2010
Conference of Chief Ministers (2001)	Power for All	2012
	100% VE	2007
Rural electrification programmes like Minimum Needs Programme (1974–79), Kutir Jyoti (1989), Pradhan Mantri Gramodaya Yojana (2001), Accelerated Rural Electrification Programme (2004)	Primary focus on villages and very poor households, no clear targets for universal access	
National Common Minimum Programme (2004), National Electricity Policy (2005)	100% HHE	2009
National Electricity Policy (2005)	Providing 1 unit/ household /day as a merit good	2012
Rural Electrification Policy (2006)	100% VE, 100% BPL HHE	2009, revised to 2012
Rural electrification programme - RGGVY (2005)		

Power for All initiative (2014)	24 x 7 power for all	Target Year: 2019[60] VE status: 98.2% (March 2016) Total HHE: 67%[61] (2011) Rural HHE : 71%[62] (2016)

5.7.1 Agriculture

The story of pump set energisation is closely linked to rural electrification, since agriculture pump sets form the main demand in rural areas and village electrification was largely driven by demands of farmer organisations. Pump set electrification picked up after the mid-1960s following the drought in 1965-67, the green revolution and the drastic reduction of tariff following agitations by farmers who demanded parity in costs of canal irrigation and pump set based irrigation. Following this, metering of agriculture connections was discontinued and a capacity based charge introduced (GoI, 1993) (Sankar, 2005). Since the tariff was low and there were shortages, the SEBs limited the hours of supply to agriculture and neglected rural electricity supply. In the years leading to sector reforms, power supply to agriculture was projected as one of the major reasons for the financial losses of SEBs. As a solution, it was proposed that all pump sets should be metered and the tariff increased to half the average cost of supply (GoI, 1993; GoI, 2001; Planning Commission, 1994). There has been very little progress in metering, though tariff has been raised in a few states, but not to the level of half of the average cost of supply.[63]

60. A revision in target was announced by the Union Power Minister during the conference of state power ministers held in Goa in June 2016. All villages are to be electrified by December 2016, 6 crore non-electrified households to be connected by December 2018, and 'Power For All' to be achieved by March 2019 (Singh S., 2016).

61. This is for all households, urban and rural, from Census 2011. Rural household electrification in 2011 was only 55%.

62. Some states like Gujarat, Goa, Andhra Pradesh and Punjab have announced 100% household electrification in 2016(REC, 2016). Recent initiatives to speed up household connections may change the situation. A clear picture will emerge only after the next Census in 2021.

63. Even when tariff is raised, usually the farmer does not have to pay more, since the state government compensates the distribution company for the difference through subsidy.

Compared to canal or tank based irrigation, the role of electricity based pump set irrigation has been on the rise since the late 1970s. Hence its importance for food security and farmer livelihood has also been increasing. As per government reports, there are around two crore agriculture pump sets in the country (increasing at around 3–4% per year) and they consume around 18% of electricity (CEA, 2015a). But the low tariff and the lack of metering have introduced many challenges in this area. This includes use of low efficiency pump sets, over-exploitation of groundwater and cultivation of water intensive crops even in water scarce areas. These in turn have led to an increasing subsidy burden on the state governments, with farmers with high capacity pump sets cornering higher subsidy. Low revenues and the spread of pump sets over large areas have led to neglect of rural distribution systems by the DISCOMs. One stark indication of the poor quality of the rural distribution system is the very high number of deaths due to electricity shocks. From 2011 onwards, the National Crime Records Bureau has been reporting around 9,000-10,000 deaths per year due to electricity shocks, with most of them occurring in rural areas (NCRB, 2015).[64]

During the initial years of the reforms, steps were taken to gradually increase the agriculture tariff, and suggestions to meter all pump sets were made. In a dramatic turnaround, many states (Andhra Pradesh, Punjab, Tamil Nadu, and Karnataka) announced free power to agriculture from 2004. During this time, power supply to agriculture had remained a neglected area, with a few hours of supply during non-peak hours, poor quality of service and rationed release of connections.[65] There were many failed attempts (by both central and state governments) to improve the situation. This included metering agriculture feeders or distribution transformers, load management techniques like single phasing[66], pilot projects to increase agriculture pumping efficiency, feeder separation and High Voltage Distribution Systems (HVDS). The primary objectives of these were to reduce unaccountable consumption (theft) in the agriculture sector. Improvement in quality of supply and 24 hours of 3 phase supply to villages were also projected as benefits (Planning Commission, 2007).

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64. See deaths due to electrocution in the annual reports 'Accidental Deaths and Suicides in India' prepared by the National Crime Records Bureau, available at http://ncrb.gov.in/

65. The hours of supply to agriculture varies from state to state, but is around 6–9 hours in states with a high percentage of consumption by agriculture (CEA 2016).

66. Single phasing refers to the practice of providing 3-phase supply on rural feeders only during the 6–8 hours for which agriculture pump sets are expected to operate. For the remainder of the time, all the three lines of the feeder are energised with a single phase so that only lighting and low capacity loads can operate. In many states like Maharashtra, this practice of virtual feeder separation was implemented without proper regulatory approvals.

Feeder separation[67] was taken up in eight states – Andhra Pradesh, Gujarat, Haryana, Punjab, Karnataka, Maharashtra, Madhya Pradesh and Rajasthan. Physical separation, i.e. separate feeders for agriculture supply, has been completed in Gujarat (and to a large extent in Maharashtra by 2012) with mixed results (Khanna & Mukherjee, 2013). The good outcomes of feeder separation include easier rationing of hours of supply to agriculture, and better quality of supply for both agriculture and villages. Rationing of power has also curtailed the subsidy burden. But the review reports indicate that even after feeder separation, outdated consumption norms are used to estimate agriculture consumption (Khanna, Mukherjee, Ghosh Banerjee, Saraswat, & Khurana, 2014). In the 12th plan, as part of the rural electrification programme (DDUGJY), many states planned to implement feeder separation (MoP, 2014c). Projects on HVDS, which involves installing small capacity transformers catering to two or three agriculture connections, have been tried in a few states, with DISCOMs claiming loss reduction and improvement in quality of supply.

100% metering of pump sets remains a distant dream in all states with a high number of agricultural connections spread over a large area. But it is unfortunate that the relatively easy task of 100% metering of all agriculture Distribution Transformers, which would help to improve the estimate of agriculture consumption, has also not been completed in any state. Similarly, even in states that have undertaken feeder separation, Automatic Meter Reading[68] of agriculture feeders is not fully implemented. The numbers and power capacity of agriculture pump sets reported by DISCOMs are also suspect, since they are based on a cumulative record of sanctioned connections. No efforts are being made to arrive at the number of non-functioning pump sets, instances of changed power rating of pump sets and unauthorised connections.[69] All these factors indicate that DISCOMs are also not very eager to arrive at a proper estimate of agriculture consumption. It is not surprising that in most states, when the newly formed SERCs started examining energy audit figures

67. Separate feeders are laid to provide 3-phase supply – one for agriculture pump sets and another for village connections.

68. Automatic Meter Reading (AMR) involves automatic measurement of electricity parameters like voltage, current and power, and regularly (hourly, daily etc.) transferring such data to the server of the DISCOM. Such a system would imply that energy measurement, recording can be free of manual intervention.

69. To illustrate, the number of electric agriculture pump sets in lakhs from different sources are: 154 (CEA, 2007), 117 (Minor Irrigation Census 2007), 127 (Input Census 2007) and 102 (Agriculture Census 2006). For the state of Bihar, the CEA reports 2.7 lakh pump set connections from 2000 onwards, Minor Irrigation Census, 2007 reports near zero electrified wells, and the Bihar Electricity Regulatory Commission reports 50,000 agriculture connections. This is based on an IWMI report (IWMI, 2012) and Prayas (Energy Group) estimates.

in 1998–2000, the figures of agriculture consumption came down and energy loss figures went up. On an all-India basis, agriculture consumption reduced from 27% to 22% between the years 1997 to 2002, whereas T&D losses increased from 23% to 33% (CEA, 2013a). The contrast is much higher in some states like Maharashtra, where the agriculture consumption estimates dropped from 27% to 16% of sales, while T&D loss went up from 18% to 31% in 1999–2000 (PEG, 2000; PEG, 2001). Assessment should be a regular exercise, but sincere efforts were not made even afterwards by DISCOMs to improve the estimation of energy consumption. Sixteen years later, when the claims of high agriculture consumption were again questioned by the Maharashtra ERC and civil society organisations, it resulted in another downward assessment of agricultural consumption. All these developments lend support to the argument that agriculture consumption estimates are inflated in order to project low T&D losses as well as to claim a higher state subsidy.

Power supply to agriculture is often mentioned as the main cause for financial losses of DISCOMs and the increasing state subsidy burden. As mentioned before, agricultural consumption has been exaggerated which implied that subsidy and cross subsidy allocated to agriculture is being used to support distribution losses and theft. In addition to the doubts about estimates on agricultural consumption, there are a few more points that warrant attention. In many states, connections to houses are also not metered, and subsidy is increasingly being used for domestic consumers as well. In some states, subsidy for domestic consumers is as high as 25% of the total subsidy. Another point is that low tariff is also supported by cross-subsidy to a large extent, but there is variation across states. Contribution of state subsidy and cross-subsidy (by paying consumers) is almost equal on an all-India basis. But state subsidy contribution is higher in states like Rajasthan, Madhya Pradesh and Haryana. On the other hand, cross-subsidy is higher in Maharashtra, Gujarat and Tamil Nadu. In some states like Maharashtra, Rajasthan, Haryana and Punjab, electricity duty collected from paying consumers is used by the state to provide subsidy — thus making it a kind of cross-subsidy. There are inequities in the distribution of subsidy, with farmers owning high capacity pump sets cornering a higher proportion. Even though the cost burden on the farmer due to electricity tariff is low compared to other costs, it is not easy to increase agriculture tariffs. While it is important to get better estimate of agriculture consumption, it is also not easy to meter all pump sets. As for financial losses of DISCOMs, there are many other reasons like unplanned purchase of high cost power, delay in payment of state subsidy, and failure to reduce losses which are discussed in Section 5.6.

Due to low tariffs, high subsidies and cross subsidies, supply quality to farmers is poor. Distribution companies have every interest in keeping tariffs low as it helps to reduce the pressure for better demand estimation and improving service quality. If distribution companies take the initiative to increase quality of supply, then there is an option to increase tariff, along with suitable support measures[70] as farmers may be willing to pay more for quality power supply.

Some recent initiatives in agriculture are the use of solar power and efficient pump sets. Solar power can be a good option for agriculture, since electricity is available in the day time. Starting from early 2000s, there were pilot projects on solar pump sets in a few states like Rajasthan and Bihar. But solar pump sets are being actively implemented after a national target of 100 GW of solar power by 2022 was announced in 2015. There are around 35,000 solar pump sets now, and there is a national target to add 10 lakh solar pump sets by 2021. With falling prices of solar power, this is indeed an attractive option, and there can be better variations like powering a whole agriculture feeder using solar power (Sreekumar, Thimma Reddy, & Prabhakar, 2016). There are also state level programmes to replace existing pump sets with efficient ones, with the expectation of 30% electricity savings. This is also a welcome measure, especially if attention is given to base-line measurements of current electricity consumption and verification of savings.

Reform attempts in the distribution sector so far have failed to meet the challenge of power supply to agriculture, because there were very few attempts and even those were not comprehensive. Addressing this complex challenge requires an integrated multi-dimensional approach involving farmers, state government and DISCOMs. There are many dimensions to be considered in addition to electricity use and supply. This includes water, land use, other inputs into agriculture, pricing and marketing of agriculture produce and credit. Only such an approach can lead to reduction of water and electricity use, while ensuring sufficient sustainable safe food production.

5.7.2 Household electrification

Household electrification was not a focus of initial rural electrification efforts, with the result that even states with high levels of village electrification had low levels of

70. Some of these support measures could be timely payment of subsidy, allocation of low cost power and designing slab wise tariff based on consumption, connected load or size of land holding.

household access.[71] It was only in 2005 that the first massive national programme with a household electrification focus was launched.

The Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY), the national rural electrification programme inaugurated in 2005, had the legal and policy mandate from the Electricity Act and the Rural Electricity Policy. The RGGVY was the first national programme with high financial and resource support from the central government and household electrification as its focus. The scope of the RGGVY was to construct substations in blocks where they did not exist, electrification of non-electrified villages and habitations (with population more than 100) and network augmentation in electrified villages, providing free connection to BPL households, and setting up small generators and distribution network in villages where grid extension is not cost effective. Rural franchisees were to be established to manage the newly set up distribution system and consumers (Sreekumar & Dixit, 2011). This programme is still being implemented with an increased scope, now with the changed name Deen Dayal Upadhyaya Gram Jyoti Yojana (DDUGJY), and is planned to continue till 2022 (MoP, 2014c).

Table 5.17: Rural electrification targets (2017) and progress till March, 2016

Parameter	Target	Cumulative achievement	Percentage achievement
Districts covered	579	-	-
Projects	921	606	-
33 kV Substations	885	632	71%
Village electrification (lakhs)	1.28	1.16	90%
Villages - intense electrification[72] (lakhs)	6.55	3.51	54%
BPL Households connected (lakhs)	420	232	55%
Total Funds (₹ Crores)	1,08,997	41,069	38%

Source: DDUGJY Progress report by the Ministry of Power (MoP, 2016f).

The scope and reported progress under this programme is indeed impressive, as can be seen from Table 5.17. It can be seen that the programme covers 90% of the districts and nearly all villages in the country. As of March 2016, 1.16 lakh

71. When RGGVY started in 2005, village electrification was around 80%, whereas rural household electrification was only 43%. States like Andhra Pradesh, Gujarat and Maharashtra, which had near 100% village electrification, had only 60–70% rural household electrification. Bihar with 50% village electrification had 5% rural household access, and Odisha with 80% village electrification had 20% rural household access (Census of India, 2001).

villages have been electrified, and 2.32 crores BPL households have been provided connections with a central government grant of over ₹ 41,069 crores (MoP, 2016f). The DDUGJY programme includes agriculture feeder separation and strengthening of rural infrastructure.

In June 2014, the government had announced the target for power for all by 2019. Power for All (PFA) is a joint initiative of the central and state governments. The stated objective is to provide 24 x 7 power to all (except agriculture, which will get 8–10 hours) by 2019. As of September 2016, state level plans are available for all seven union territories and 27 states (only Tamil Nadu and UP remain). These plans have five-year projections for demand, generation, fuel, transmission, distribution, renewable energy, energy efficiency and supporting services. A state PFA report is an attempt to consolidate all on-going and planned state and central programmes in one place. The scope of PFA includes assessing requirements for universal access and planning generation and transmission capacity to meet the new demand. Demand estimation for households is made with the assumption of universal access and consumption levels based on current average values. Electrification targets are higher than that of DDUGJY, with all non-electrified households planned to be electrified. The DDUGJY estimates were largely based on BPL connections and normative values for load and energy consumption. Like DDUGJY, the Ministry of Power is responsible for the monitoring of the PFA programme, with state DISCOMs expected to provide inputs. There is a dashboard for PFA and village electrification which is to be updated by local functionaries, and a mobile application for village and household electrification.[73] Finances for PFA are to be raised from private players and state and central governments.

However, issues involving planning, implementation and sustainability of rural electrification programmes persist. It is difficult to believe in target dates for electricity for all since they have been revised many times. Issues reported in rural electrification programme include delays in meeting the targets, slow pace of increase in access, reducing scope, and increasing cost estimates (Planning Commission, 2014c; Rural Electrification Corporation, 2013; Standing Committee on Energy , 2013; Standing Committee on Energy, 2009). Between 2005 and 2012, there has been only around 10% increase in household access and no improvement

72. Intense electrification of villages refers to increasing infrastructure and connections in electrified villages.

73. The website www.powerforall.co.in gives all state plans and details of review meetings. Dashboard and mobile application www.garv.gov.in gives updated village and household electrification and infrastructure details, and has a facility for updating of data by village and district functionaries.

in average hours of supply, with rural areas facing an average of 9 hours of power outages every day (Desai S. A., 2007; Desai S. a., 2011). During the same period, there was a 66% increase in net generation. There have been many gaps in quality monitoring with no reliable method to measure the actual hours of supply or capture consumer issues. Though there are a few recent reports by the MoP on hours of supply which show significant improvement in supply[74], other measures show there is a long road ahead. Data captured by the Electricity Supply Monitoring Initiative (ESMI) of Prayas[75], with over 250 devices spread over the country, indicates low voltages , frequent interruptions, and low hours of supply. Table 5.18 shows data from ESMI devices for 5 megacities for the month of October 2016. It is clear from the table that even large cities with a population of more than 20 lakh receive no supply for an average of 3 to 11 hours per month.

Table 5.18: Supply quality in megacities in October 2016

Mega City	ESMI Locations	Average number of interruptions per location		Average no supply hours (hours of outage) per location
		15 min - 1 hour	> 1 hour	
Jaipur	6	5	1	3
Hyderabad	11	7	1	4
Bengaluru Urban	11	13	1	6
Kanpur	7	14	1	10
Chandigarh	5	3	1	11

Source: (PEG, 2016c).

Data from ESMI devices also show that only 67% of the locations in megacities,56% of the locations in smaller cities and just 16% of the locations in rural areas receive six hours of supply in the evening (PEG, 2016c). Such independent verification efforts are crucial to ensure accountability.

The rural electrification programme has been planned in a top-down manner,

74. The DDUGJY reports till mid-2015 were stating the rural power supply position for the last three months. The average hours of supply in a day in the period June – August 2015 has an average of around 17 hours, is as low as 8–10 hours (in Uttar Pradesh, Assam, Bihar, Jharkhand, etc.), and as high as 20–23 hours (in Andhra Pradesh, Gujarat, Kerala, etc.) (MoP, 2015a, pp. 13-14). The recent reports again state rural power supply position for the previous month. Report for the month of October 2016 indicates an average daily hours of supply above 20 hours, with 13-20 hours in some states (Assam, Bihar, Jharkhand, Jammu & Kashmir, Karnataka and Haryana), and less in some north-eastern states (Mizoram and Arunachal Pradesh) (MoP, 2016h). But in the absence of consumer side power supply monitoring systems and a lack of transparency of feeder metering information, these figures are not very reliable.

75. Please see reports available at http://watchyourpower.org/uploaded_reports.php.

with very little participation from states (Sreekumar & Dixit, 2011). The rural distribution franchisees, which were to operate the newly set up network and service consumers, have not taken off, since there was no clear business model for them. Reports commissioned by the Rural Electrification Corporation in 2007 indicate that the franchises have helped to improve the quality of service in some areas. But most of them were involved in revenue collection only, and there were franchisees operational in about 30% of the villages. Perhaps due to these experiences, in the current version of the programme, franchisees are not mandatory. But it is unfortunate that no other alternative arrangements for rural distribution management are suggested. There has been very little public oversight on the implementation of the DDUGJY, no state level regulatory reviews and the functioning of district electricity committees has not been satisfactory. The network and connection drives have been initially planned only to cater to BPL households or 10% of the village households. This excludes many households which are not identified as BPL. It is not clear if network and power supply will be sufficiently augmented to cater to all households and productive loads like agriculture and other rural enterprises. With poor availability of electricity supply and absence of franchisees, the new network may remain underutilised and poorly maintained. There are doubts about whether the targets for PFA will be met and whether the power provided will be affordable for all (Josey & Sreekumar, 2015).

Increase of APL consumers, provision of 24 x 7 power supply and growth of economic activity are crucial to rural development and gradual improvement of financial health of the distribution company. Since rural BPL consumers will have low tariff, at current cost of the supply of power, the distribution company loses nearly 4–5 rupees for every unit supplied to them (Josey & Sreekumar, 2015).

Some suggestions to improve the implementation of the 24 x 7 Power For All efforts are given below:

- Connection drives to ensure universal access: Procedure for connection should be simplified and connection drives organised to target all households and productive loads with 100 meters of a transformer or line. Connection charges should be reduced, or an option provided to pay it in instalments or to partly subsidise it[76].

76. Some recent review meetings of PFA and speeches by the Union Minister of Power have suggested connection drives and reducing connection charges for APL households.

- Provide low cost power to DISCOM for 24 x 7 power supply: Low cost power should be made available to the DISCOM so that the disincentive to supply to the rural poor is reduced. This can be through allocation of captive coal blocks, low cost power from UMPPs, depreciated plants or stranded or backed down plants with some cost support from the government.
- Move from 100% village electrification to PFA divisions and districts: Since all villages are soon expected to be declared electrified as per the current definition, plans should be prepared to roll out PFA divisions and districts. These districts will have all households and public places in all villages electrified, with at least 12 hours of supply available, distribution infrastructure set up to cater to latent demand, and periodic certification by the district electricity committee.
- Develop institutional infrastructure to manage rural distribution: Since rural franchisees are not planned, the DISCOM should be strengthened to manage rural distribution and address consumer complaints.
- Improve district and state level monitoring: In addition to national level reviews, SERCs should also be involved in monitoring progress and conducting public reviews of rural electrification. Targets for household connections and quality of supply at the consumer level should also be a performance metric for the distribution company. State review committees and district electricity committees should have spaces for public participation.

A good rural electrification programme should be comprehensive, involving infrastructure creation, universal access, affordable electricity supply and quality service. There should be institutions to monitor the implementation of the programme, manage the system, and ensure long-term sustainability. Such a programme should work hand in hand with rural development efforts which focus on other factors like credit, market access and skill development, so that income generating activities are promoted. Current programmes are at best limited to infrastructure and connections. Many papers and government reports have pointed out these issues (Sreekumar & Dixit, 2011; Sreekumar, Josey, Chitnis, & Dixit, 2013; Josey & Sreekumar, 2015; GoI, 1980; Standing Committee on Energy , 2013; CAG, 2014b), but even today the rural electrification efforts are not comprehensive towards catalysing rural development.

5.8 Transmission – need for caution while moving out of state ownership

Many would remember the two massive grid collapses in July 2012. The first one on 30th July led to a power blackout of an area with around 30 crore people. The second and bigger one on 31st July affected a bigger area with 62 crore people, nearly half the Indian population, spread over the north, east and north-eastern regions. Transmission bottlenecks have made it difficult to evacuate power from Chhattisgarh and the North East to power shortage states like Tamil Nadu, Karnataka and Delhi. Wind generators in Tamil Nadu are often backing down generation since there is no transmission capacity to carry power, and Gujarat DISCOMs are forced to run expensive plants and back down cheaper plants due to bottlenecks. The cost of power in the southern region is often high just due to capacity limitation of the inter-regional transmission corridor. New 'green transmission corridors' are being planned to evacuate power from large solar parks that are being set up. Private investments have started rather recently in this high investment sector. All these events have increased the focus on the transmission sector. Perhaps due to the technical complexities or lack of direct consumer interface, there are very few public interest groups in transmission.

The network of transmission lines interconnects all generating stations at one end and the distribution substations at the other. This network is the national electricity grid, which also interconnects all the five regions of the country — northern, eastern, north-eastern, western and southern. There are Transmission Companies (Transcos) at national and state levels, involved in construction and operation of inter-state and intra-state transmission lines and substations respectively. The Load Dispatch Centres (LDCs) at the state, regional and national levels are responsible for reliable and efficient operation of the national grid. The national grid helps to optimise generation resources and increase the reliability of power supply. Electricity flows from one end of the country to another through the national grid, under the supervision of the LDCs. The state transmission system is typically managed by state Transcos, whereas POWERGRID, the central public sector transmission company manages most of the inter-state transmission system. From 2006, there has been slow growth of private players, especially in inter-state transmission. Table 5.19 gives the major milestones in development of the transmission sector.

Table 5.19: Major milestones in the transmission sector

Year	Milestone
1950-60	Growth of state grids and introduction of 220 kV
1964	Regional planning of transmission, Regional Electricity Boards set up under CEA
1965–73	Interconnecting state grids to form five regional grids – northern, eastern, north-eastern, western and southern
1975–88	Growth of central sector generation and transmission systems under NTPC and NHPC, growth of regional grid systems
1989–92	POWERGRID, the central sector inter-state transmission company set up by separating the transmission wings of central generating companies, RLDCs set up under CEA
1994–96	RLDCs transferred from CEA to POWERGRID
1997–2000	NR and NER grids interconnected, transmission planning on a national basis, first Indian Electricity Grid Code (IEGC) issued in 2000. See Box 5.2 for details on grid code and Availability Based Tariff
2003–06	Electricity Act - open access in transmission. All regional grids except southern interconnected
2008–10	National Load Dispatch Centre set up. POSOCO notified to operate RLDCs and NLDC, as a wholly owned subsidiary of POWERGRID
2012–16	Blackouts in July 2012 bring attention to the importance of coordinated grid operation (CERC, 2012). National Reliability Council for Electricity (NRCE) set up in 2014 (CEA, 2014). Southern grid connected to rest of Indian grid in 2014, which means that the whole country can possibly operate at a single frequency. Revisions in IEGC to increase grid discipline and integrate renewables (CERC, 2014a). Slow increase in private participation in transmission

Source: (CEA, 2012a; PGCIL, 2015) and as mentioned in this table.

Box 5.2: Indian Electricity Grid Code – IEGC

Development of the Inter State Transmission System (ISTS) to form a national grid had commenced in 1997. It was noticed that the frequency was low during peak hours, high during non-peak hours, and there were wide variations in the frequency, leading to many grid disturbances (CERC, 2000). To improve the situation, the CERC introduced two major initiatives – the Indian Electricity Grid Code and Availability Based Tariff in 2000.

For the reliable operation of the national grid, it is important that all generators and consumers who connect to the grid follow some rules and

guidelines. The Indian Electricity Grid Code (IEGC), notified by the CERC first in 2000 and revised many times subsequently, serves this purpose. IEGC is to be followed by all users of the national grid who connect to the Inter-State Transmission System (ISTS – which carries electricity from one state to another). The IEGC specifies the role of different actors interacting with the ISTS. This includes major generating stations, transmission companies and DISCOMs which are physically connected to the ISTS; Load Dispatch Centres (LDCs) at the national, regional and state levels; as well as planning and monitoring agencies like the CEA and Regional Power Committees. The IEGC clearly lays out the norms for transmission planning, guidelines for connecting to ISTS, and operational procedure for generators, transmission companies, DISCOMs and LDCs. The IEGC specifies the frequency and voltage levels that are to be maintained in the national grid as well as the penalties for not maintaining it. The SERCs have also issued state grid codes along the lines of the IEGC.

The CERC also introduced the Availability Based Tariff (ABT), a better tariff mechanism for bulk sale or purchase of electricity in 2000. The ABT has three components: (a) capacity charge, linked to the plant's declared capacity to supply MWs, to reimburse the fixed cost of the plant, (b) energy charge for scheduled generation to reimburse the fuel cost and (c) a payment for deviations from schedule, at a rate dependent on grid frequency.

The IEGC and ABT helped to improve the discipline in the operation of the national grid. The current IEGC is the version released by the CERC in 2010, with many subsequent amendments including scheduling norms for renewable generation and penalties for voltage deviations. The UI charges were also revised from time to time by the CERC with tightening bands of frequency deviations and increasing penalties on generators or DISCOMs for causing frequency deviations. After the Electricity Act in 2003, there was growth of electricity markets, which consisted of contracts with power traders and real time market under UI. There were many issues with the operation of the UI market and there was a strong view that UI should not be opportunistically used as a short-term power procurement mechanism.

After the 2012 grid collapse, based on wide consultations, the CERC repealed the UI regulations and introduced a more comprehensive Deviation and Settlement Mechanism (DSM) in 2014 to strengthen grid discipline. A report on the 2012 grid failure noted that frequency is not the only parameter to be monitored and controlled for grid safety. Voltages, transfer capacity of transmission lines, and fault levels are also equally important. The explanatory memorandum of the CERC on DSM notes that: "The Utilities have overlooked the need for planning generation adequacy over a period and have not gone for adequate capacity additions and relied on over-drawal from the grid for meeting their consumer demands … The grid security is of paramount importance and cannot be sacrificed. Further due to integration of regional grids, the economic cost of grid failures is too high and grid failures should be avoided at all costs" (CERC, 2015c). The grid failure report also noted that frequency control through UI may be phased out in a time bound manner and generation reserves/ancillary services may be used for frequency control. DSM is elaborated in the section on electricity markets.

It is expected that DSM regulations, IEGC, increase in transmission capacity, improved load dispatch facilities, and subsequent introduction of ancillary services (like peak power, reactive power support, etc.) by the CERC in 2015 will stabilise the national grid operation.

Transmission is critical for the power sector and has to grow harmoniously a few steps ahead of the growth in generation and demand. This sector involves significant investments and impacts the lives of many people due to the wide-spread impact of grid failure, and also land required for construction of lines and substations. As per the CEA, out of the ₹ 1 lakh crore total investments in the sector in 2009, 20% was in transmission, 20% in distribution and the remaining in generation (CEA, 2009). In the 11th and 12th five year plan estimates, investment estimate for transmission was to the tune of ₹ 1.4 to ₹ 1.8 lakh crores, amounting to 15% of the total investment in the power sector (Planning Commission, 2012a). The importance and complexity of the transmission sector has been growing because of the continuous strengthening of the national grid, introduction of competitive bidding, entry of private players, emergence of electricity markets, and increasing renewable capacity. But unfortunately, the transmission sector is out of the radar of most public interest groups.

5.8.1 Reform and competition in transmission

The transmission sector has been largely owned and operated by the government, except in a few urban pockets like Mumbai and Kolkata. In the last two decades, this sector has been the slowest in moving out of state ownership. Table 5.20 captures the major steps in introducing privatisation in transmission.

Table 5.20: Major steps in privatisation of transmission

Year	Step	Remarks
1998	Amendment to Electricity Act 1910	Recognised transmission as a separate activity, made provision for transmission licensee
2000	Guidelines for private participation in transmission	Two options — first one being a JV with CTU/STU owning 26% equity and the second one being Independent Private Transmission Company with 100% equity by private company. CTU/STU to identify segments. Limited interest by private players.
2003-2006	Electricity Act 2003, National Electricity Policy 2005, Tariff Policy 2006	E-Act: Transmission licensing, open access, tariff based bidding Electricity Policy: Special mechanisms to be created to encourage private investment in transmission sector Tariff Policy: Mandatory tariff based competitive bidding after 2011
2006	Tariff based competitive bidding guidelines for transmission	14 mega transmission projects identified for Build, Own, Operate and Maintain (BOOM)
2006	First PPP transmission project operational	Tala transmission project – a JV between TATA (51%) and POWERGRID (49%), 400 kV D/C between Siliguri (WB) and Mandola (UP)
2008	Planning commission task force on policy and regulatory framework for private participation in transmission (Planning Commission, 2014b)	Documents developed for private participation – model RFP for consultants (2007), model RFQ & RFP for PPP projects (2007) and Model Transmission Agreement (2010). Final report submitted in 2014
2010-2011	CERC approval for 11 high capacity transmission projects, mostly private	Total investment of about ₹ 74,500 cr.
2011	Amendment to Tariff Policy	Exemption to intra state transmission projects from competitive bidding till 2013 and exemption for select/urgent projects

2014	Move by CERC to provide General Network Access[77] to transmission	This is expected to be more market friendly. (CERC, 2014c; MoP, 2015b)
2015	18 projects worth ₹ 25,000 crores awarded through competitive bidding, 9 of them in the last one year, 6 commissioned (Jha, 2015). Green corridor projects planned to evacuate power, awarded to POWERGRID	Transmission tariff reported to be 30-40% lower, POWERGRID won 9 projects
2016	Private participation low at 3-6%, but trend towards higher private	Transmission projects worth nearly ₹ 1 lakh crores awarded through competitive bidding in 2015-16, with POWERGRID winning projects worth ₹ 56,000 crores and private players projects worth ₹ 35,000 crores. There are plans to bid out projects worth nearly ₹ 50,000 crores in 2016-17.[78]

Source: (PFCCL, 2015; CEA, 2016b; CEA, 2012a).

It can be seen from the last row in Table 5.21 that the private participation in transmission is still quite low, with centre and state players dominating the sector. Table 5.21 gives the pattern of ownership in the transmission sector.

Table 5.21: Pattern of transmission ownership (March 2016)

Ownership	Lines		Substations	
	CkM	%	MVA	%
Central	1,29,364	38%	2,43,281	37%
State	1,92,144	56%	3,97,341	60%
JV[79]/Private	20,043	6%	18,327	3%
Total	3,41,551		6,58,949	

Source: CEA monthly report March 2016 (CEA, 2016b).

77. The National Electricity Policy and Tariff Policy mandate that national inter-state transmission tariff frame work should be sensitive to distance, direction and quantum of flow. Accordingly, the CERC in 2010 notified the regulations for sharing inter-state transmission charges. The method described in the Regulations is known as point of connection (PoC) tariff. This approach has some limitations and General Network Access (GNA) is expected to be an improvement. The idea is that the generator and the consumers could be given GNA to the Inter State Transmission System for the agreed quantum of power (MW). It is expected that the GNA agreement could become the driver for investment.

78. As stated by the Union Power Secretary and reported in The Economic Times, 14th October, 2016(PTI, 2016)

79. POWERGRID is involved in many Joint Ventures (JVs) in transmission like Powerlinks (49%), Torrent (26%), Jaypee (26%), Parbati Koldam Transmission (26%), Teesta Valley Transmission (26%), North Eastern Transmission (26%), Cross Border Transmission (26%), Power Transmission Nepal (26%), Bihar Grid Company (50%), Kalinga Vidyut Prasaran Nigam (50%) and RINL POWERGRID (50%). Figures in brackets indicate % share of POWERGRID(PGCIL, 2016).

Interest of private players in the transmission sector has been growing in recent years. At the end of the 11th plan, in March 2012, private players/JVs owned only 3% of the transmission circuit km and 1% of the substation capacity. During this plan, there was hardly any private investment in transmission, whereas in the 12th plan, 14% of the total ₹ 1.8 lakh crores investments in transmission are expected to be made by private players (Planning Commission, 2012b).

5.8.2 Challenges in competition

Unlike generation, transmission, a natural monopoly, is not considered amenable to competition and has been dominated by state players for many years. Need for high investment and risks on returns (owing to uncertainties in electricity sector planning) could have acted as deterrents to privatisation. Close coordination with generation capacity addition and demand growth is the major challenge. The spread and capacity of multi-state private generating plants have been increasing, with many of them operating as merchant plants, without any long term contracts. Growth in markets and renewable generation has introduced many unknowns in actual power flows and hence the capacity utilisation of the transmission sector. The national grid is still not able to cater to the needs of inter-regional power flows, though it is expected to be fully equipped to do this by 2017 (MoP, 2015b) While there are reports of transmission congestion in some areas preventing smooth transfer of power, there are also reports of under-utilisation in some other. Ensuring grid security and high utilisation of installed capacity are conflicting requirements and a proper balance is to be established.

After SEB unbundling, there was one transmission company in each state, and POWERGRID handled all inter-state transmission at the national level. As per the Electricity Act 2003, the central government is to notify a government company as the Central Transmission Utility (CTU), and the state government is to notify a government company as the State Transmission Utility (STU). Accordingly, POWERGRID, a central government public sector company, is the CTU and the state transmission companies are the STUs. The functions of the transmission utility include:

- Undertaking transmission of electricity
- Planning and coordination of transmission system with other transmission utilities (STUs for CTU and CTU for STUs), government, generating companies, DISCOMs, CEA, etc.

- Providing non-discriminatory open access, on payment of required transmission charges.[80]

POWERGRID, as the CTU, has access to grid related information and thus has some advantages while competing for projects. Industry associations like FICCI, Association of Power Producers and EPTA (Electric Power Transmission Association) have expressed concerns over the barriers to competition in the transmission sector. One of the issues raised is the dominance of POWERGRID in inter-state transmission. There have been reports of project delays and problems of congestion in some areas which have surplus transmission capacity in case of POWERGRID projects (CAG, 2014a). POWERGRID has won projects through competition, but has also been awarded projects (green corridor project in Rajasthan, southern region link, etc.) on a nomination basis citing urgency. There are doubts if POWERGRID should play multiple roles like a developer and a Central Transmission Utility (CTU) with specific responsibilities for national grid and grid operator, being the owner of regional Load Dispatch Centres (LDC). At the same time, there are concerns if the central and state regulatory commissions will be able to provide the required oversight for the construction and operation of private transmission companies towards protecting public interest.

There has been inordinate delay in separating Load Dispatch from CTU. Power System Operation Corporation (POSOCO) was set up in 2009 to manage national and regional load dispatch centres, but it remains as a wholly owned subsidiary of POWERGRID till today. Talks on making POSOCO a separate organisation have been going on from 2013, but it is still not clear when this will happen. At the state level, according to the E-Act, the state transmission company is supposed to manage only the transmission system, but is still managing grid operation, since the separation of LDC from the transmission company is not complete. In most states, the DISCOMs continue to function under the overall guidance of the transmission company. This includes management decisions and power purchase.

The actual amount of power that can be transferred over a transmission line is much less than its capacity. The transmission capacity is limited by the limits of permissible rise of conductor temperature, whereas the transfer capacity depends on the dynamic parameters of the grid like voltage, generation and required

80. CTU is the nodal agency for medium (3–36 months) and long-term (12–25 years) open access, whereas the RLDC coordinates short-term (up to 3 months) and NLDC the Power Exchange transactions (CERC open access regulations).

reserve margins. Congestion occurs when the required amount of power to be transmitted is more than the available transfer capacity. A recent report by a CERC subcommittee (CERC, 2015d) notes that the available transfer capacity (decided by the Load Despatch Centre) is often 20-30% of the transmission capacity, and has been leading to congestion in many areas, thus reducing power transfers.[81] Real time modelling of the grid and quick corrective actions are required to reduce congestion. This will be a big challenge to ensure proper power transfers, open access and market operation (CERC, 2015d).

At national and state levels, transmission sector planning has been a big challenge, because of poor load forecasting and generation capacity addition planning. Use of short-term open access by many generators, forming long-term access agreements for transmission without long-term power purchase contracts, growth of renewable capacity (which has shorter gestation time compared to transmission systems and whose power generation cannot be perfectly predicted), backing down of generators and short-term markets (which also introduce uncertainties in power flows) pose challenges to transmission planning. If we are not able to face these challenges, there is the danger of under-utilisation of transmission assets (CERC, 2014b). Blackouts have shown that unregulated grid operation can cause extensive damage to vast populations. In the transmission sector, most of the policies, regulations and guidelines are prepared at the national level, and participation by civil society actors in these processes has been very less. This is not a good sign, since the next decade may witness the opening up of the transmission sector with many private players and increased complexity of operation. If sufficient checks and balances are not present in the planning and operation of the grid, there is a danger of underutilisation of investment, increased cost burden on consumers and more blackouts in the grid. Civil society needs to build its capacity and expertise in transmission to be able to participate effectively.

5.9 Regulatory commissions and accountability of electricity utilities

Regulators were introduced to aid the transition of the sector to a decentralised market system, to ensure financially sustainable operations of the DISCOM and to instil investor confidence (World Bank, 1993a).With this push, regulatory commissions (whose mandate focussed on tariff determination) were introduced via some State Acts and the Central Electricity Regulatory Commissions Act,

81. Annexure IV of the same report gives a wide range of ratios for European countries, but some are as high as 70–90%.

1998. The scope and mandate provided to the ERCs was further broadened in the Electricity Act, 2003 to include greater powers to ERCs to hold utilities accountable and protect public interest. Nevertheless, the focus of this institution remained tariff determination and ensuring market development.

This section will take a critical look at the impacts of regulatory institutions on power sector governance, especially with respect to increasing transparency, participation and accountability. With a greater role envisioned for private sector actors as well as market operations, the role of the regulator will be critical during the transition period towards the future electricity industry structure. In addition, the release of the draft regulatory bill signals that regulatory institutions will be instated in other sectors as well (NITI Aayog, 2015). In both cases, some of the crucial lessons learned from the electricity sector experience so far could prove useful.

5.9.1 Effectiveness of regulatory institutions in ensuring accountability

In the initial years, the ERCs took many decisions to safeguard public interest and ensure sustainability of sector operations. In the 1980s and 1990s, the national average cost of supply (ACoS) grew at 10% and 12% per annum respectively. Between 2000–01 and 2010–11, the decade where SERCs were active, the ACoS increased by only 4% per annum. It is possible that other factors have also contributed to this decline in growth, but ERCs did take many critical steps to contribute to it. Some examples include seeking audited accounts from utilities and scrutinising power procurement contracts. With such scrutiny by ERCs, the design and enforcement of contracts greatly improved (Dubash & Rao, 2007). ERC regulations helped develop processes and norms which all utilities had to comply with. For the first time, both private and public companies were being held publically accountable for their performance in the tariff determination process or via compliance to ERC directions. The ERCs were also provided with penal provisions which enabled them to impose penalties[82] for non-compliance and to suspend or revoke licenses[83] with necessary cause. After the 2012 grid failure, the CERC issued show-cause notices under Section 142 to invoke penal provisions in order to ensure the establishment of a grid communication and telemetry system. In 2015, the ERC in Odisha revoked the license of the 3 private DISCOMs due to non-compliance of ERC directions.

82. Sections 142 and 146 of the Electricity Act 2003 empower the ERCs to impose penalties in the nature of fines or imprisonment or both, depending on the severity of the non-compliance. These sections can also be used to hold an individual officer responsible for her duties, if the ERC so chooses. Section 128 also empowers commissions to investigate the affairs of a generating company or licensee in case of non-compliance to provisions of the Act.

83. Regulators also have powers to revoke and suspend licenses under Section 19 and Section 24 of the Electricity Act, 2003 respectively.

Regulatory commissions also have the mandate to ensure supply and service quality by instituting regulations and norms for voltage, interruptions, network failure, time taken for providing a connection, etc. Failure to meet these norms can entail compensation by DISCOMs to consumers for poor service. Compliance to supply and service norms as per the Standards of Performance regulations has to be reported by the DISCOM to the regulator on a periodic basis as per Section 59 of the Electricity Act,2003.[84] Accountability of DISCOMs towards consumer supply and service quality based on these norms and complaints from consumers is handled by the 3-tier grievance redressal mechanism of which Consumer Grievance Redressal Forums (CGRFs) form an important part. This is discussed in Box 5.3.

Box 5.3 Complaint handling mechanism and DISCOM accountability

Most complaints with respect to supply quality, metering, billing and other services are first handled by the internal grievance redressal cell at the section or sub-section office of the DISCOM or by using toll free telephone numbers for complaint handling. In case these complaints are not addressed, consumers can approach the Consumer Grievance Redressal Forum (CGRF) which each DISCOM is to institute as per Section 42 of the Electricity Act. CGRFs have three or four members and their composition varies across states (Sreekumar, 2015). In some states like Haryana and Maharashtra, there is one legal member, one technical member and one consumer member, and in others like Rajasthan, there are only technical members. In most states the technical member is an employee of the utility and the consumer member is usually an independent member. Many states like Karnataka, Rajasthan, Haryana and Delhi also have multiple CGRFs in the DISCOM area. Despite multiple forums, access is limited due to legalistic processes and lack of awareness. Issues of service quality and compliance with standards of performance are not given as much importance as issues with metering and billing. Consumers can appeal against CGRF orders before the Electricity Ombudsman. Compliance with CGRF and Ombudsman orders by the utility is low as these bodies do not have penal provisions. Compliance is also low because ERCs do not conduct a suo-motu process to check compliance, and consumers face hurdles in approaching ERCs to ensure compliance (Swain & Singh, 2015).

84. While these provisions exist, it is also true that compensation for poor service quality is often not claimed by consumers or paid by the utility. Moreover ERCs also have not been regular in publishing reports showing compliance to the Standards of Performance (SoP) norms.

5.9.2 ERCs as custodians of public interest

The inception of ERCs brought in greater transparency and access to information and provided for participatory public spaces in the decision making process. All proceedings before the ERC are open to the public, and almost all[85] commissions often have public hearings for tariff determination and granting of licenses. All ERC regulations are notified after public consultation, and the ERC's orders are supposed to be 'reasoned orders'[86] which capture all viewpoints presented during proceedings. In the past, consumer and public interest groups have been able to intervene effectively in decision making processes, not just pertaining to service delivery and consumer issues, but broader governance issues as well. In the first tariff process in Maharashtra, such groups were able to call for a re-assessment of agricultural consumption and T&D loss reduction provided by the MSEB (Maharashtra State Electricity Board), which resulted in losses standing at 31% instead of the 18% reported by the MSEB (PEG, 2001). Small consumers were able to communicate their issues which helped rationalise their tariffs.[87, 88] Public interest groups were also able to intervene in power procurement related matters, call for investigation into DISCOM operations, and prevent pass through of avoidable expenditure to consumer tariffs. The ERCs were also able to institute innovative solutions for persistent issues. In the face of shortages in Maharashtra, the ERC initiated a load shedding protocol to ensure that shortages are shared equitably (Chitnis & Josey, 2015). The ERCs in Tamil Nadu and erstwhile Andhra Pradesh conducted public processes to evaluate shortages and impose restriction and control measures. The ERC in Bihar changed its regulations such that lack of property ownership ceased to be a barrier to obtaining legal connections (BERC, 2012). Additionally, the CERC played a key role in promoting power markets in a gradual fashion, and ensured transparency in market operations with regular

85. The West Bengal's SERC is an exception to this. The WBERC has been persistent in not conducting public hearings for tariff determination and has stuck to the narrow interpretation of public consultation for tariff determination as specified in the Electricity Act, 2003.

86. Orders which document objections and suggestions of all parties and which provides reasons for the decisions taken in the order.

87. The MERC in August 2012, after submissions from various groups, set the same tariff for LT domestic, industrial and commercial consumers using less than 300 units. Previously these consumers were paying tariffs as high as large commercial or industrial consumers, and were being harassed in case they had domestic connections. This move benefitted over 3.5 lakh consumers (MERC, 2012).

88. Similarly in Tamil Nadu, small commercial establishments submitted that they are being charged at par with much larger consumers due to their categorisation as commercial consumers. In order to address this, the TNERC introduced slabs wise tariffs for commercial consumers such that consumers using less than 50 units in a month were charged at a rate lower than those using more (TNERC, 2010).

monitoring and publishing of analysis reports of trends. After the grid failure in 2012, the CERC also improved grid security through many regulations and tighter norms.

The ERCs have exercised their mandate beyond techno-economic decision making, and have made significant progress despite the interference due to political agendas, lack of political authority, lack of information and weak capacity. There are functioning regulatory commissions in other sectors and spheres as well, including water, telecommunications, petroleum and natural gas, as well as the competition commission. However, the mandate and powers provided to electricity regulators is much greater than in the Acts governing the above mentioned regulators. This is especially true in the context of ensuring transparency, accountability and participation (PEG, 2009). Therefore, it is important to preserve these institutions and increase their legitimacy and capacity.

5.9.3 Limited use of powers and its impact on the sector

Despite progress, it is also true that the ERCs make limited use of the powers to hold utilities accountable and to advise governments. In spite of persistent and costly delays in submission of required information for the tariff or performance review processes, the SERCs have seldom exercised their mandate under Section 142 or Section 146 to ensure compliance from utilities. In case state governments fail to make promised subsidy payments in advance as per Section 65 of the Electricity E Act, 2003, the ERCs have the powers to approve tariffs without considering the subsidy announcement. Barring a few exceptions, no ERC has used this power. By not exercising these powers, they are as responsible for accumulating losses as the loss making DISCOMs.

Moreover, SERCs often limit their role to tariff determination and rarely grapple with issues plaguing the sector. No SERC has devised a roadmap for financial turnaround of utilities based on public consultation. Further, systematic reviews of generation capacity addition have not been conducted, nor has the progress under rural electrification programmes been reviewed. Even though space has been created via the E Act and subsequent regulations, not much is done proactively by individual ERCs to encourage public participation.

5.9.4 Need for capacity building to ensure informed participation

Despite the myriad number of issues faced by small consumers with respect to electricity, most petitions filed before the SERCs are from large commercial and

industrial consumers. Only three SERCs have appointed consumer representatives to present consumer interests before the commission as per Section 94 (3) of the E Act. Prior to public consultation in the tariff determination process, the SERCs conduct meetings to review information provided in the petition and request for more data to aid analysis. Expect the Maharashtra SERC, no other SERC invites consumer representatives for these meetings. It has been said that most consumer groups have the will, but do not possess the technical know-how or the economic capability to present sound analysis from a public interest perspective (Rao, 2011). However, SERCs do very little in terms of providing knowledge and financial support to consumer groups to encourage informed participation. Due to a lack of timely bold decisions, innovative solutions and absence of proactive measures to encourage wide public participation, the credibility and legitimacy of regulatory processes are under threat.

5.9.5 Appeals against ERC orders

Regulatory commissions do not always act in public interest and sometimes do make decisions which can impact the supply quality and tariffs for a large section of consumers. Regulatory commissions can also affect sector viability as well as consumer welfare with their inaction in some areas. This is evident in the lack of attention given by ERCs to issues of long-term planning, access, supply and service quality. As per the E Act, any person aggrieved by an order of any ERC can appeal to the Appellate Tribunal for Electricity. For small consumers, access to the Appellate Tribunal is not easy. As of 2016, the fee requirement for each appeal is set at ₹ 1 lakh. This is ten times higher than the fees needed to appeal before High Courts, and is also significantly higher than the fees charged by appellate tribunals for similar infrastructure sectors. In fact, most cases filed before the ATE are by private generators, state DISCOMs and large consumers with a negligible number of filings from small consumers.

5.9.6 Independence and capacity of regulators

Although envisaged as independent entities to increase sector accountability, ERCs often have reduced autonomy. The ERC members and the chairperson are appointed by the state government based on the recommendations of a selection committee. Across India, on an average, 70% of ERC chairpersons appointed were secretary level bureaucrats in the state. About 44% of the other ERC members were previously employed with the regulated utility in the same state.[89]

89. This is based on PEG analysis of regulatory appointments from the inception of the state ERC till the year 2013.

In case of vacancies, ERC positions are seldom filled on time. On an average, across the country, since the inception of ERCs, the position of the chairperson has been vacant for 6 months and that of members for 14 months.[90] This weakens the institutional capacity of ERCs and in the absence of a full quorum, the legitimacy of processes before it are undermined. There is evidence in literature from different countries to show that delays in appointments could be used as a tool to influence policy by finding key players who support the prevailing government's stance (Nixon D. C., 2001). Increased media scrutiny and concern from interest groups on the type of appointment could also delay the process (Nixon & Bentley, 2006). It order to mitigate delays, the decision to nominate candidates for the position at the state level can be automatically transferred from the state selection committee to the CERC selection committee.

Lack of capacity also undermines the independence of regulators and is still a serious issue with most regulators being poorly staffed, relying heavily on consultants and government officials and even staff from regulated utilities sent on deputation.

The broadened mandate provided to ERCs enabled the creation of spaces which could help depoliticise an essentially political sector. With more voices being heard in the spaces created, actions were also taken to limit the ERC's mandate. Overarching state and central sector policies, circulars and orders directing an ERC to contemplate a course of action effectively attempts to control decisions of 'independent' ERCs. The letter from the Ministry of Power on compensatory tariff provision on a case by case basis for competitively bid generation projects, and the interpretation of the Ministry of Law and Justice with respect to Open Access, are good examples of this. In many cases, subsidies provided by the state government, finance unsustainable operations and undermine regulatory decisions. A good example of this practice would be when subsidies finance additional power purchase to offset T&D losses incurred over and above the levels specified by the ERC.[91] None of the large central government programmes including RGGVY, PFA, UDAY and IPDS included ERCs in their review and monitoring processes, even though ERCs are supposed to scrutinise large capital expenditure works being implemented by utilities. This shows that even central and state governments do not make space for the regulator in power sector policy implementation.

90. This is based on PEG analysis of regulatory appointments from the inception of the state ERC till the year 2013.

Despite the various instruments used to control ERCs, reduce their legitimacy and weaken their powers, the ERCs help create a space for public participation in decision making which is unique and needs to be preserved and expanded. To make the regulatory model work, there is a need for strong commitment towards the regulatory mechanism from central and state governments (which requires them to be willing to give up some of their powers and privileges) as well as adequate public pressure.

5.10 Conclusions and lessons

Two decades of reforms after reforms in distribution have introduced many changes, but the sector remains almost at the same stage. Even now, it is grappling with the challenges of meeting the goal of providing affordable reliable power supply, making the distribution companies financially healthy, fulfilling the need for network expansion and strengthening grid security. The various structural and technological changes which accompanied the reforms brought additional challenges as well as opportunities. Challenges include broadening and deepening of markets, grid integration of renewable energy and regulating private players. Opportunities include the policy focus on DISCOM performance, thrust for rural electrification, and the institutionalisation of regulatory commissions with the potential for accountability and oversight. This section consolidates the conclusions and lessons and offers some suggestions. We hope that the next wave of reforms would benefit from these.

5.10.1 Crisis driven, mechanical policy making approach

Reform efforts have often been knee jerk responses to impending crises without adequate reflection on past efforts. The restructuring of state electricity boards and privatisation of distribution companies were such responses, taken with the hope of attracting private investments. It was also a response to the pressure from the World Bank and other international lending agencies. Unbundling was replicated in many states even though the Odisha experience did not result in the expected improvement in efficiency, independence from the state government, or commercial orientation. The series of bailout schemes, with conditions on DISCOMs, were in response to the alarming indebtedness of power suppliers or lenders. Enough

91. This is true for subsidies provided for additional power purchase needed as loss reduction targets could not be met. Subsidy provision also acts as a disincentive for utilities to ensure more scientific methods for agricultural demand estimation.

thought was not given to address the repeated failure to honour conditions against borrowing, meeting efficiency targets, leading to erosion of financial stability.

5.10.2 Weak planning and poor implementation

Even while grappling with issues in the sector, there were gaps in characterising the problems and therefore pressing issues were often not given enough attention. This misdiagnosis and lack of prioritisation led to sustained failure in policies achieving the desired objectives. One example is the attention to AT&C loss reduction and tariff increase to address financial viability issues, without much focus on faulty power purchase planning, increasing expenses and reckless borrowing. Additionally, planning is often myopic with little regard for future eventualities. The most prominent example is in the case of power procurement. A short-sighted response to shortages has resulted in DISCOMs being stuck with capacity much in excess of demand. Similarly, the transfer scheme which was of utmost importance to give the newly formed DISCOMs a clean start, was not completed in almost all states.

Weak planning and inherent resistance to change have left DISCOMs unprepared for structural and technological shifts in the power sector. Open access was introduced almost a decade ago, but resisting DISCOMs are still unprepared for the impact of sales migration. At the central or state levels, there were limited efforts towards redesigning tariffs to rationalise cross-subsidy, developing open access consumer contracts to mitigate risks taken by DISCOMs, and evolving approaches to safeguard the interests of small consumers. Even though the development of power markets was considered an essential part of the reform process, the markets continue to be fragmented and split due to information asymmetries, transmission constraints, market concentration in some segments and limited number of market instruments.

Policies and regulatory decisions often do not adequately address operationalisation and implementation challenges. This approach has resulted in key changes being operationalised through litigation. One such example is the introduction of parallel licensing in Mumbai, where the arrangement was operationalised through a series of litigations in the face of regulatory ambiguity. Review of past efforts and mid-course correction based on learning is also not part of planning efforts and policy decisions. Rural infrastructure is inadequate to cater to growing demand, as the initial targets were to supply to only BPL households or 10% of the village population. Feeder separation could have been used to improve measurement of agriculture

consumption, but in Gujarat, the first state to implement the programme, even now agriculture consumption is estimated based on pump set consumption norms.

5.10.3 Essential need to build centre-state synergy

Given the concurrent nature of the electricity sector, there is a need for greater cooperation and dialogue between central and state power sector agencies. In the past, central sector interventions tended to have a 'one size fits all' approach which resulted in implementation issues when subjected to state level ground realities. Some examples include the resistance in operationalising open access, failure in implementing bailout schemes, dismal efforts to ensure universal metering, avoiding regular tariff increase, lack of attention to energy efficiency and delays in implementation of centrally sponsored programmes. Without political buy-in and commitment by the states, reform efforts will not succeed. The joint plans for UDAY and PFA are steps in the right direction towards centre-state synergies to address state specific needs.

5.10.4 Low attention to institution building

Implementation of various reform efforts have also faltered due to the weakness of institutions. There has been repeated failure to strengthen the DISCOMs to function as agile, innovative and healthy institutions. Even after corporatisation, little was done to increase their capacity and institutional capability. A massive rural electrification programme was planned with significant resources, but there was no matching effort to set up institutions to manage the newly created infrastructure and consumers. Though regulatory commissions were set up in all states, they continue to suffer from lack of capacity and resources and limited efforts were made to increase informed participation of consumer groups before ERCs.

5.10.5 Lack of information, regular review and effective monitoring

It is difficult to analyse the progress of reform efforts without availability of information and transparent reviews. Despite major investments, there is very little information available on the extent of accumulated financial losses and factors that have contributed to it. Details of debt restructured in previous bailouts have also not been reported. Baseline AT&C losses assessed through energy audits as well as information and analyses on the performance of franchisees are not available. There is also limited information with respect to short-term market transactions, making it difficult to understand market concentration and ascertain issues to be addressed to ensure robust market development.

In addition to lack of availability of information, there has been no systematic and public review of various large scale programmes like the DDUGJY, IPDS, UDAY and its predecessors to ensure accountability, aid mid-course correction and inform policy revisions.

5.10.6 Limited success in ensuring of accountability of institutions

In a cost-plus regime, generation, transmission and fuel supply companies pass on their inefficiencies to the DISCOMs. Recovery of these high costs through tariffs is politically difficult and thus state-owned DISCOMs are saddled with losses. DISCOMs seldom exercise their right to hold other agencies accountable for inefficiencies in performance. This is true for sub-contractors (for capital works or operation and maintenance), franchisees and power generators with which they have signed PPAs. This could be due to reduced autonomy, lack of capacity or lack of incentive to do so, as costs are recovered through tariffs or bailouts.

Since its inception, ERCs have increased transparency in decision making processes, ensured participation of stakeholders and have been able to hold licensees accountable in certain matters. The space that ERCs have created is unique and needs to be preserved and expanded. However, it has not been very consistent or effective in ensuring accountability due to lack of capacity and issues with appointments. This has also reduced the legitimacy of regulators. Additionally, there is the need of holding regulators accountable. Regulatory decisions can be challenged before the Appellate Tribunal but as discussed in Section 5.9.4, this not an easily accessible route. Another challenge is the lack of established processes to hold regulators publicly accountable for their decisions.

Many actors which influence DISCOM operations such as banks and fuel supply companies operate outside the ambit of electricity regulators. This lack of direct accountability for their actions has resulted in a situation where fuel suppliers, generators, transmission companies, traders and equipment suppliers have managed to stay in business, whereas distribution companies have been consistently making losses. With increased private participation and deepening of markets, better accountability mechanisms across sectors and more informed performance based pricing will become essential.

5.10.7 Neglect of crucial issues

Over the years, there have been several crucial issues which were not given any importance by policy makers and planners. Universal access to electricity services

was one such area until the launch of RGGVY in 2005. Supply and service quality is also a neglected area. With all the talk of surplus power and the push to increase tariffs, it is surprising that the performance of the DISCOMs is not evaluated on the basis of service quality. Small consumers who do not have the political and economic power to present their concerns are also neglected and under-represented in policy making and regulatory processes. Limited efforts have been made to increase their informed participation in regulatory or policy forums. Electrical safety is another issue where not many initiatives have been undertaken. Over 9600 people die in a year due to electricity accidents (NCRB, 2015). But the office of the Chief Electrical Inspector to the Government (CEIG), responsible for ensuring safety, remains outside the ambit of any public accountability mechanism, and DISCOMs do not include safety in their performance metric. Energy efficiency is another neglected issue by the DISCOM, and all recent initiatives are led by the central government.

5.10.8 Lessons and suggestions

Observations made in the previous section with respect to DISCOM operations, policy and planning approach were perhaps true even before the advent of reforms. However, several technological and structural changes in the last decade have created alternative supply options for high paying consumers. This development calls for questioning the traditional approach of DISCOMs. DISCOMs have to rethink their continued reliance on cross subsidy, question their assumptions of perpetual demand growth and analyse the need for increased power procurement, while attempting to be financially viable and provide reliable access to all. Such enquiries can lead to planned and phased transition towards a more suitable business model. It is important to begin this transition now, as it would be tougher in the near future when DISCOMs would be forced to take crisis-driven, sub-optimal decisions.

For example, DISCOMs could think of having separate treatment for large consumers (who have the choice to migrate) and small consumers (who are dependent on the DISCOM). High tariffs, phased reduction of cross subsidy surcharge and fixed duration contracts[92] could encourage large consumers to make their own supply arrangements. This segregation would reduce the scale of DISCOM operations and thereby improve power procurement planning and efficiency. Small consumers, on the other hand should be provided with tariff certainty by linking tariff increase to

92. Fixed duration contract will provide consumers with assured supply by the DISCOM and prevent frequent switching by the consumers between the DISCOM and alternative supply options.

inflation rates. Tariff design could also have more intra-category cross subsidies to ensure adequate revenue recovery. Support to small consumers could be provided to encourage productive use in the form of adequate and low cost power.

In order to be competitive with alternative supply options, DISCOM efficiency has to improve. This could happen with the effective implementation of MYT. DISCOMs will require financial support during the transition period but this should be limited and monitored. DISCOMs which have surplus power can reduce costs by restructuring existing PPAs after accounting for demand growth.

An effective transition requires strong regulatory institutions, monitoring of supply and service quality and robust markets. For example, to enhance independence of regulators, selection can be from a wider pool of candidates. In order to address the issue of capacity of senior regulatory staff, a regulatory cadre, similar to the administrative services, could be planned. In order to encourage market operations, introduction of year-long contracts in power exchanges as well intra-day markets instruments to create a viable market for standby power will be crucial. Increased scrutiny of market operations and regular analysis of market trends would also contribute to removing information asymmetries. Ultimately a DISCOM should be evaluated based on the supply and service quality its consumers get. Therefore there is always a need for strengthening independent monitoring and evaluation of consumer service.

6

The Indian coal sector: A black past and a grey future

"Our fathers sinned and are no more; And we have borne their inequities"[1]

6.1 Introduction and overview

Historically, the stories of the Indian coal and electricity sectors have been tightly intertwined. In 2015–16, coal was the source of nearly two-thirds of electricity produced in the country, and about two-thirds of coal consumed in the country was used to produce electricity. Moreover, relative abundance of the resource domestically, and the likelihood of domestic coal-fired electricity being the cheapest source of electricity at least for the short term[2], means that it still has an important role to play in the electricity sector of a country with high levels of energy poverty. Coal is India's most important source of primary energy, supplying about 45% of it in 2016.[3] Though the share of renewables is expected to increase rapidly in the coming decades, coal is likely to remain a significant contributor to the overall energy basket in the short to medium term.

The sector is likely to see some significant changes in the near future. The passage of the Coal Mines (Special Provisions) Act, 2015 has enabled the possibility of commercial mining in addition to auctioning and allotment of coal blocks for

1. Lamentations, Chapter 5, Verse 7, The Bible

2. While the rapid fall in prices of renewable technologies are likely to bring them on par with coal-based generation soon, direct comparisons are tricky given the challenges of grid integration.

3. Computed from (BP, 2015) and estimates of non-commercial bio-energy consumed in the country for which no reliable data exists.

captive use. Some mines have already been given to state owned entities under this Act for commercial mining in August 2016 (MSTC, 2016). The government has also announced an ambitious coal production target of 1.5 billion tonnes per year by 2020, with Coal India Ltd. (CIL) producing 1 billion of the target (IANS, 2015). A proposal for auctioning coal linkages was approved by the Cabinet Committee on Economic Affairs in February 2016, and the first round of auctions to the non-power sectors began in June 2016 (PIB, 2016a). The sector is under pressure due to increasing concerns of local and global environmental impacts, falling global coal demand and rapidly falling prices of renewables. For all these reasons, it is useful to critically review the evolution of the coal sector over the last two decades and learn lessons from it.

India's coal sector is currently governed by the Ministry of Coal (MoC). The sector was nationalised in the 1970s with the passage of the Coal Mines (Nationalisation) Act, or CMNA (MoC, 1973). Subsequent to nationalisation, the public sector coal mining behemoth, CIL, was born and is the world's largest coal producing company in 2016 producing around 80% of India's domestic coal.[4] The provision to allocate captive coal blocks for end-use consumption[5] was introduced in the 1970s, with steel being the first sector to which this was applicable. Power generation was added as a notified end-use for which captive blocks could be allocated in 1993, since it was felt that CIL would not be able to keep with the expected surge in demand from opening up the power generation sector. The other major developments in the coal sector from the early 1990s to August 2016 included the decontrol of coal pricing in 2000, the adoption of the New Coal Distribution Policy (NCDP) in 2007, the publication of an audit report by the Comptroller and Auditor General (CAG) in 2012 regarding captive block allocations and augmentation of coal production, the cancellation of most captive coal block allotments by the Supreme Court in 2014, the passage of the Coal Mines (Special Provisions) Act or CMSPA in 2015, the allocation of blocks under this legislation for captive use (to public and private companies) and commercial mining (to public companies), and the commencement of auctioning linkages by CIL in 2016.

Over the years, recognising the importance of coal to the economy, the government set up various committees to review the coal sector and recommend policies and

4. https://www.coalindia.in/en-us/company/aboutus.aspx

5. That is, coal blocks would be given to companies who can mine the coal and use it in their own power plant, steel plant or cement plant, and they will not be able to sell the coal.

strategies to improve efficiency and mining practices. The important coal-related committees and their findings and recommendations are summarised in Table 6.1.

Table 6.1: Coal-related recommendations in various government reports

Report	Key findings / recommendations
Fuel Policy Committee, 1974 (Planning Commission, 1974)	• Urgent need for systematic exploration of coal reserves • Need for integrated development of coal and railway infrastructure for evacuation • Need to find ways to improve usage of mining equipment and productivity • Need to plan for washeries for non-coking coal
Working group on Energy Policy, 1979 (Planning Commission, 1979)	• Need to continually monitor coal demand • Need to devise strategies for technology adoption and utilisation • Integrated planning and development of coal and railways for evacuation • Washing of non-coking coal where economically viable
Towards a perspective on energy demand and supply in India in 2004-05, 1985 (Advisory Board on Energy, 1985)	• Need to intensify coal exploration and identify reserves • Need to plan for integrated development of coal mining and transport infrastructure
Committee on Integrated Coal Policy, 1996 (Planning Commission, 1996)	• Breaking up CIL into smaller subsidiary companies that compete with each other • Setting up an independent coal regulator • Allocation of coal blocks based on competitive bidding in which Indian companies could participate
Roadmap for coal sector reforms, 2005 and 2007 (MoC, 2005; MoC, 2007b)	• Time-bound plan to map the entire country's coal reserves by the end of the 11th five year plan • Restructuring CIL and subsidiaries, and separating Central Mine Planning and Design Institute (CMPDI) • Simplification of clearance processes • Replacing fuel supply agreements (FSAs) with fuel supply and transport agreements (FSTAs) • Greater transparency and effectiveness in captive mine allotment • Greater coordination between the MoC and the MoP • Setting up an independent coal regulator

The extraction, processing, transport and consumption of coal have significant environmental implications. Mining and transport of coal affects air quality as a result of particulate matter pollution. Coal mining could also impact water resources by affecting aquifers and streams. Much of the coal in India is found in densely forested areas of Chhattisgarh, Jharkhand, Madhya Pradesh and Odisha. Therefore, coal mining also has negative impacts on forest cover and biodiversity. Moreover, since such forested areas are typically home to a large portion of India's tribal population, coal mining tends to disrupt their way of living and often results in their displacement. Combustion of coal in power plants results in air pollution through escaping particulate matter and other polluting gases such as NOx and SOx. As Indian coal has high ash content, the pollution of land, air and water near its consumption point is exacerbated unless the ash is dealt with thoroughly and carefully. Finally, combustion of coal is one of the major causes of climate change because of the large quantities of CO_2 released by its combustion. Policies for the coal sector need to be understood keeping these factors in mind.

In this chapter, we focus mainly on a set of reforms related to coal allocation — allocation of coal 'linkages' to consumers and allocation of captive blocks. These reforms are chosen because resource allocation is an important issue with significant downstream implications. The chapter also briefly discusses a set of 'neglected reforms' — issues that the reforms never addressed, though there was a pressing need to deal with them.

6.2 Allocation of coal through linkages

After the nationalisation of the coal sector, coal was allocated to consumers, including power plants, by the Ministry of Coal in the form of 'linkages' based on which Coal India Ltd. would supply coal to the consumer.[6] In 1993, power was notified as an end-use of coal for which captive coal blocks could be allocated, subsequent to which power companies could request not just for coal through linkages from CIL or other public mining companies, but request for a coal block itself, from which they could extract coal for their power plants. Thus, as of the early 2000s, there were two routes available to a coal consumer for obtaining domestic coal. The first was through the 'linkage' route and the second was to be awarded a coal block for captive use.

6. The actual process by which the MoC allocated linkages and the contractual arrangement between the consumer and CIL in the 1970s and 1980s period are unclear.

However, there was no well-defined policy governing allocation of coal linkages as a result of which small consumers had great difficulty accessing coal. Some of these consumers, such as Ashoka Smokeless, approached the courts regarding their difficulty in getting coal at reasonable prices. In response, the Supreme Court ruled that the government should introduce a policy for coal linkage allocation in order to allocate coal among various consumers and prevent its black marketing (Supreme Court, 2006). This led the government to introduce the New Coal Distribution Policy (NCDP) in 2007 (MoC, 2007a). It should be noted that earlier committees too had suggested reforms in the coal linkage process, but it took a Supreme Court order for the government to develop the NCDP.

Under this policy, all coal consumers (except those requiring less than 4200 tonnes per annum) could apply to the Standing Linkage Committee (Long-Term), or SLC (LT) comprising of representatives from ministries such as coal, power and steel for coal linkages. For power sector consumers, the NCDP promised that "100% of the normative requirement of consumers would be considered for supply of coal". Once the SLC (LT) approved the issuance of a letter of assurance (LoA) — also loosely called a linkage, an LoA would be issued to the coal consumer by the corresponding subsidiary of CIL or Singareni Collieries Company Ltd. (SCCL) stating that the linkage would be converted into a legally binding Fuel Supply Agreement (FSA) once the consumer meets certain milestones, such as achieving financial closure and obtaining various clearances within a stipulated period.

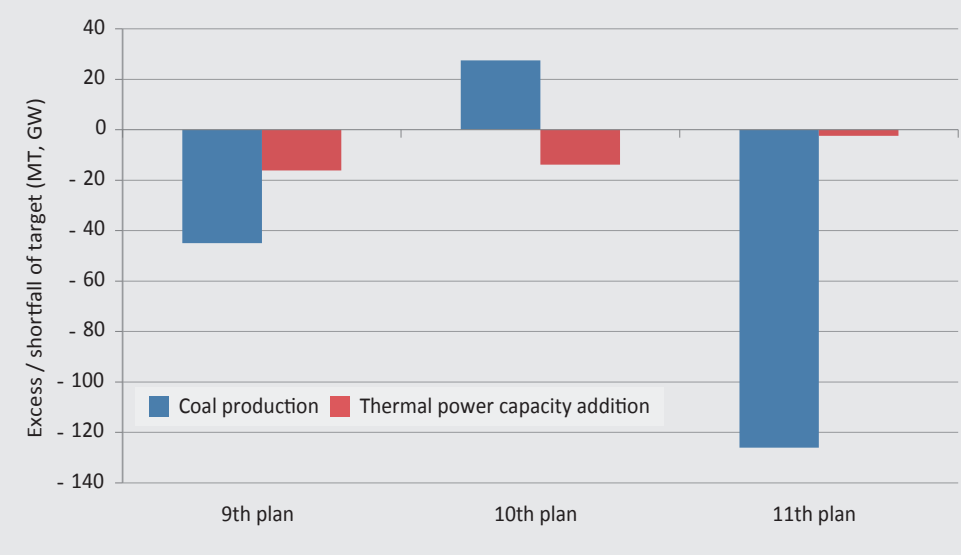
A few years subsequent to the introduction of the NCDP, India faced a huge coal shortage leading to a 'crisis' in the power sector (Livemint, 2012). It was felt in some circles that with the passage of the Electricity Act (E Act) in 2003 and de-licensing of power generation, thermal generation capacity was added rapidly (mainly by the private sector), while coal production — still a controlled sector — could not keep pace. It was felt that the shortage was not felt earlier as both coal production as well as power capacity addition fell short of target[7] in earlier five year plans.

Figure 6.1 partially supports this hypothesis. Coal production and thermal power capacity addition were both short of target in the 9th five year plan (ending 2002). However, coal production in the final year of the 10th five year plan (ending 2007) exceeded the target by 28 million tonnes, while thermal power capacity addition was 14 GW short of the target. In the 11th five year plan (ending 2012), the situation

7. Questions can also be asked about how the two targets were decided, but that is beyond the scope of this book.

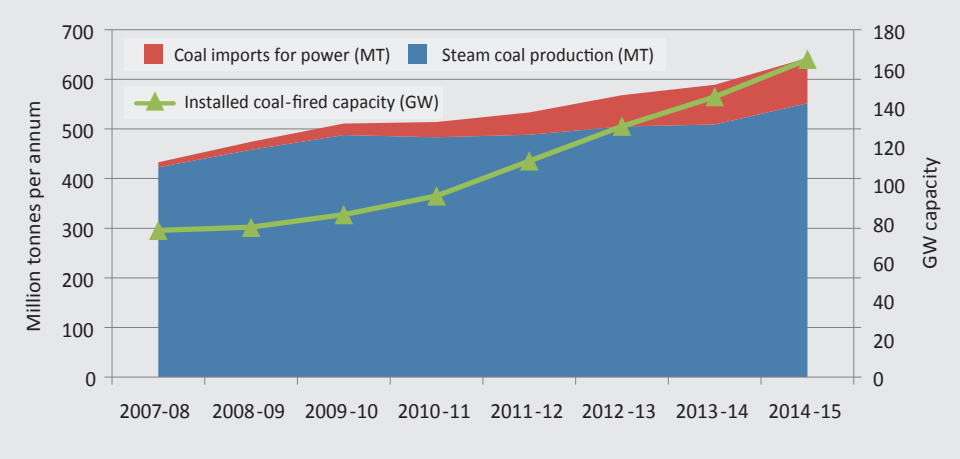
was turned on its head, with thermal power capacity addition nearly meeting its target, while coal production in the final year of the plan fell as many as 126 million tonnes short of target.

Figure 6.1: Relative achievement of coal production and thermal capacity addition



Source: Relevant five year plan documents, coal directories and Central Electricity Authority (CEA) reports.

Figure 6.2: Steam coal production, coal-fired power capacity and coal imports for power



Source: Various CEA reports and coal directories.

As depicted in Figure 6.2, coal-fired capacity went up by about 115% from 76 GW in March 2008 to about 165 GW in March 2015 but production of steam coal, used mainly in the power sector, went up by only about 30% from 423 million tonnes per annum (MTPA) to 552 MTPA[8]. The country was caught cold by this disjointed development of two closely related sectors, power and coal. As a result, imports of coal by the power sector surged by almost 800% between 2007–08 and 2013–14, going from about 10 million tonnes (MT) to over 90 million tonnes.

But how true is the claim that the shortage was due to a rapid increase in power generation capacity as compared to expected domestic coal production? Alternatively, if domestic coal linkages were allocated based on likely domestic production, why did the shortage of domestic coal come as a surprise to power generators? Or had something gone wrong with the envisaged scheme of awarding linkages through NCDP? This section presents a summary of a detailed analysis of these questions (PEG, 2014a).

The power generation capacity did increase rapidly after opening up the sector. However, for such a capacity increase to be financed or commissioned, they would have needed some kind of assurance regarding fuel supply. Therefore, all the capacity that came up had some such assurance — mostly in the form of LoAs which did not translate to actual coal production. Thus, the causality is, in fact, the reverse — so much capacity could come up *because* corresponding quantity of LoAs were granted. Were the LoAs granted consistent with realistic coal production, or were they granted generously beyond any realistic possibility of satisfying them from domestic coal? An analysis of the NCDP and the minutes of the SLC (LT) meetings which decided about granting LoAs reveal that it was in fact the latter: LoAs were granted well in excess of planned coal production.

The clauses in the NCDP only stated that LoAs would be granted. But they were silent about where the coal would be sourced from to meet linkage requirements other than stating which CIL subsidiary would be responsible to supply the coal. They neither denied coal linkage to any party, nor did they promise that all the committed quantity of coal would be supplied from *domestic* sources. They did not state any criteria by which an applicant would be considered for LoA, or criteria to decide how much of a consumer's needs would be met from domestic sources.

8. The situation had improved marginally by March 2016 due to significantly increased coal production in 2015-16. Thermal capacity had gone up to 185 GW (140% increase over 2008) while steam coal production had reached 607 MT (40% increase over 2008).

Instead, the NCDP merely stated that in order to meet its linkage commitments, CIL (and its subsidiaries) may have to import coal and the costs of such imports would have to be borne by the consumer, without stating how the imports would be distributed among different consumers. Similar clauses, permitting coal imports if required, were also present in the template LoA and FSA.

To compound the ambiguity of the NCDP, the minutes of the SLC (LT) meetings do not indicate that the SLC (LT) used any objective criteria to decide which applicants get linkages and which should not. As a result, the SLC (LT) granted linkages to many consumers desirous of obtaining linkages without considering the ability of CIL and its subsidiaries to meet the linkage requirements from their production. This is in spite of CIL representatives at SLC (LT) meetings repeatedly stating that they would not be able to honour the amount of linkages being granted from their production (MoC, 2008; MoC, 2008a; MoC, 2008b). In spite of this, the SLC (LT) continued to grant linkages without clarifying how much of each linkage would come from domestic production, and how much from imports, and instead relied on CIL to supply the coal through a mix of domestic and imported coal.

The distinction between domestic and imported coal is important because of the significant price difference between them, which in turn, would impact the viability of the power generation project. For example, in 2012, when the coal shortage was felt severely, the price of Indian coal of 3700 kcal/kg was about ₹ 550 / tonne, while the landed price of Indonesian coal of 5000 kcal/kg was about US$ 65 / tonne (about ₹ 3500 / tonne) — which made the imported coal about 4 times as expensive on a per kilocalorie basis.[9]

Consequently, linkages were granted far in excess of CIL's ability to produce coal, with this glaring ambiguity regarding the source of coal for each linkage. This led to convenient (and contradictory) assumptions by coal suppliers and consumers. Coal consumers, such as power generators, built up a lot of capacity as each consumer assumed that they would get domestic coal, though there was no contractual assurance to that effect, since the NCDP, the draft LoA and the draft FSA all clearly mentioned that imports may be required to satisfy the linkage. Based on this assumption of domestic coal availability, many of them bagged contracts by quoting low and non-escalating tariffs to supply a significant

9. International coal prices have softened since 2012 and domestic coal prices have increased. Hence, the gap in mid-2016 between international and domestic coal prices would be lower, but international coal would still be more expensive on a per kilocalorie basis.

amount of power, and more than 70% of the domestic coal based power generation capacity that was contracted through competitive bidding between 2006 and 2011 (excluding Ultra Mega Power Projects) was based on coal linkages (Gadag, Chitnis, & Dixit, 2011).

If individual power generators interpreted the NCDP and LoAs conveniently, bankers and others who lent to power generators were equally guilty as they agreed to support the capacity being built up by the power generators. They too chose to go with the story of the borrowers that their capacity would be based on domestic coal, though there were clear indications — in the minutes of SLC (LT) meetings, realistically likely domestic coal production and even fuel risks noted in red herring prospectuses of power producers (IndiaBulls Power Limited, 2009), that this was not true. Clearly, their sectoral intelligence gathering and due diligence had failed. For their part, CIL and its subsidiaries assumed that they were only obliged to produce as much coal as they could, and that even if they did not meet the production target, the balance requirements could be met through imports for which the coal consumers would pay.

This assumption of domestic coal availability and generous financing enabled a lot of coal-based capacity, more than 40GW or about a fifth of total installed coal-based capacity in 2016, to be contracted between 2006 and 2010 based on aggressive tariff bids. Not surprisingly, as these projects came close to commercial operation and domestic coal supplies were nowhere near the expected levels, the situation came to a head. This led to a clamour against CIL's inefficiencies and monopolistic practices. There was a lot of pressure on the government to modify the terms of the FSA and force CIL to supply domestic coal to all consumers according to the LoAs. It even resulted in a Presidential Directive being issued to CIL (PIB, 2012), asking it to supply coal to all those who had been awarded LoAs, though it is not clear how anybody expected CIL to instantly ramp up its production to meet the demand from domestic sources. Since CIL could not possibly have complied with the Presidential Directive in spirit, it chose to comply with it in letter by proposing an FSA to supply the promised quantity of (domestic) coal, but with a penalty of only 0.01% if it failed to supply it (CIL, 2012, p. 14)!

This farcical situation was partially and temporarily salvaged by modifying the NCDP to clarify how much coal can be assured from domestic sources up to 2017, with the rest of the coal requirement to be met through imports. But since imported coal is costlier than Indian coal per kilocalorie as well as per tonne, the

cost of generating electricity would still go up[10], and the question was who would bear the increased cost of electricity. The government wrote to all the regulatory commissions in July 2013 suggesting that they could consider passing on the increased cost of power generation to consumers on a case by case basis, while keeping the larger public interest in mind.[11] As consumer representatives[12] felt that such a pass-through of tariffs is not legitimate, it has led to multiple litigations which are still being pursued as of December 2016 to determine the legal tenability of such revisions of competitively discovered tariffs.

If the increased costs of power generation are indeed passed on to consumers, it would effectively punish them for the ambiguous drafting of the NCDP by the government, overly generous linkage allocation by the SLC (LT) and convenient interpretations of the various documents by power generators, their financiers and coal companies. In addition, it would reward power producers and lenders for the undue risks taken by them based on unjustified assumptions and thus potentially compromise competition and contractual sanctity.

While the number and quantum of linkages granted was large and has led to many problems, the number of applicants for linkages was even larger. An office memorandum from the MoC states that applications were pending for power sector linkages alone for up to 600 GW of coal fired capacity, requiring about 2,700 MTPA of coal (MoC, 2013a). This represents more than three times the installed coal-based power generation capacity in 2016, and about five times the then annual production of coal in India. It is telling that in spite of such heavy competition for linkages, and the lack of any clear, objective criteria to award them, there are no known instances of applicants — particularly those who did not win linkages — complaining about the manner in which linkages were granted or filing law suits about the manner of linkage allocation. The reason for this silence is left to the imagination of the reader.

It is also interesting that the coal shortage issue did not receive such high profile media attention earlier, though problems of coal supply from CIL had been highlighted by public sector power generators as far back as the 1980s or 1990s. For

10. As discussed in Chapter 2, Too good to be true: The story of thermal generation, generators have sought a tariff increase in the range of ₹ 0.35 / kWh to ₹ 1.5 / kWh on account of this.

11. It should be noted that suggestions from the central government are not binding on state electricity regulators, so they need not necessarily permit passing through increased costs of coal.

12. Prayas (Energy Group) is one of the consumer groups involved in these litigations.

example, the Maharashtra State Electricity Board (MSEB) had reported coal short supply of over 20% for five consecutive years from 1987–88 to 1992–93 (MSEB, 1988 - 1996), but that does not seem to have created many ripples nor any serious corrective action initiated.

6.3 Allocation of coal blocks for captive use

The history of coal block allocations for captive use in the power sector can be seen in two phases. The first phase covered the allocation of blocks from 1993 to 2010 and culminated with the Comptroller and Auditor General's (CAG) audit report of 2012 and Supreme Court judgements of 2014. The second phase is on-going and consists of coal block allocations made and being made under the Coal Mines (Special Provisions) Act, 2015. This section presents a critical review of both these phases.

6.3.1 Captive block allocations (1993 – 2010)

In 1976, the Coal Mines (Nationalisation) Act had been amended to allow captive mining for notified end-uses and notified steel as an end-use. In 1993, power was notified as an end-use, meaning blocks could be allocated to power generators.[13] The ostensible reason for notifying these sectors for end-use in the early to mid-1990s was that demand for coal would accelerate significantly corresponding to the expected spurt in economic growth, and hence the private sector should also be invited to play a role in the process. The analysis of the first phase of block allocations presented here is primarily based on information from some documents published by the MoC, the 2012 audit report of the CAG, and judgements of the Supreme Court (CAG, 2012; Supreme Court, 2014a; Supreme Court, 2014b).

Over 200 coal blocks containing about 50 billion tonnes of reserves were allocated between 1993 and 2010. In the initial years, allocations were made by the Ministry of Coal based on recommendations from respective state governments. Subsequently, an inter-ministerial screening committee, consisting of members from the MoC, MoP, railways and the concerned state government, was formed to decide who should be the beneficiaries of a captive coal block allotment. While most mines were allocated for captive use, a few mines were also given to state government companies for commercial mining.

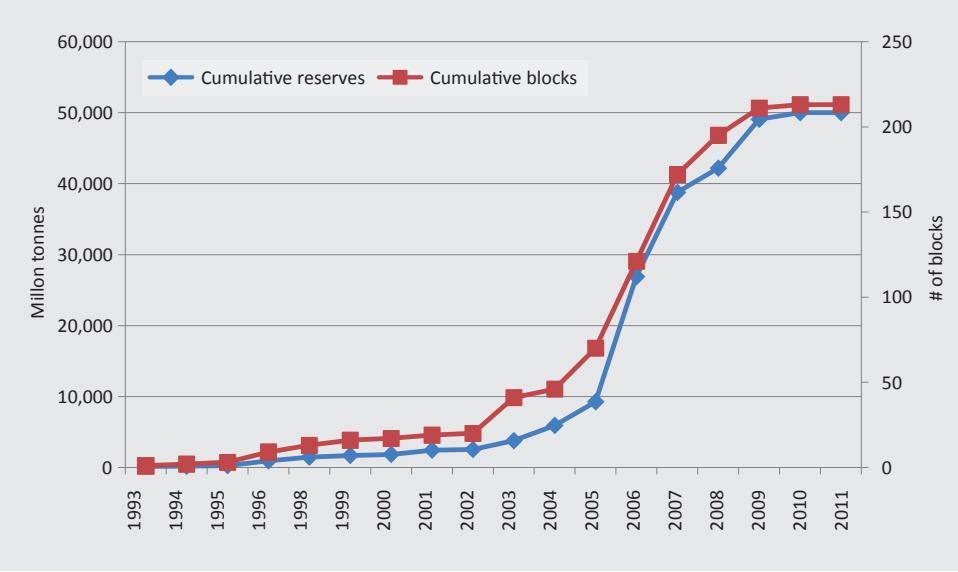
In its audit, the CAG found that blocks had been allocated to aspirants based on very weak or ad-hoc criteria. The minutes of the screening committee's meetings often

13. Cement was added to this list in 1996.

did not list the reasons why a particular block was allotted to a particular applicant. In many cases, only some of the applicants for a block were given a chance to make a presentation to the committee. For example, only 36 out of the 69 applicants for the Fatehpur block could make presentations to the committee, while for the Rampia and dip-side of Rampia blocks, only two out of 101 applicants could do so. Curiously, in the latter case, though only two applicants could make presentations to the committee, the block itself was allotted to a consortium of six companies. The Supreme Court concurred that blocks had been allocated without "application of mind" and that the allocations suffered from "the vice of arbitrariness".

In 2004, the then Secretary, MoC presented a comprehensive note on competitive bidding as an objective way of identifying allottees for coal blocks. In response to the question of the legality of this proposal, the Department of Legal Affairs opined in 2006 that the then existing legal framework was sufficient for the government to conduct auctions to allocate blocks. In spite of this, no action was taken until 2010 when the Minerals and Mines (Development and Regulations) Act, or MMDRA, was amended to make it mandatory to choose private sector beneficiaries of captive coal blocks through auctions. Interestingly, as can be seen from Figure 6.3, about 75% of the blocks and reserves were allocated between 2004 and 2010, i.e. after the proposal to auction blocks was mooted and before some action was taken in that regard.

Figure 6.3: Cumulative captive coal blocks allocated between 1993 and 2010



Source: Documents from the Ministry of Coal.

The captive blocks were given to private (and public) sector companies with no conditions attached. Thus, there was no need for them to pay any additional royalty or other amount to the government, nor was there a requirement for them to pass on the benefits of receiving this 'free resource' to their consumers. The CAG estimated that, as a result, the private sector stood to make windfall gains of around ₹ 1.8 lakh crores. The possibility of such undue gains was pointed out at a meeting of the screening committee by one of the states, but the committee did not act upon it.

Based on the CAG report, a Public Interest Litigation was filed in the Supreme Court, on which the Court ruled in August and September 2014. In its orders, the Supreme Court cancelled most of the block allocations and also made some scathing observations on how the allocations were made.[14]

1. **Illegalities in allocation:** It observed that, in the first place, the central government was not authorised to decide who would be the beneficiaries of coal blocks as that right belonged to state governments under the MMDRA.[15] Many mines were allotted to joint ventures or consortiums, though this was not permitted by the CMNA. Allotment of mines to state governments for commercial mining was also illegal as only central government owned companies could engage in commercial mining according to the CMNA. On these counts, the allocation of most blocks was deemed illegal.
2. **Procedural irregularities:** The Supreme Court concluded that the screening committee exceeded its brief in various ways. They chose to club blocks or sub-blocks that had been demarcated without providing any rationale. Before September 2005, blocks were allotted without any public advertisement, thus seriously limiting the pool of applicants to only 'those in the know'. The committee introduced innovations such as 'leader company' and 'associate companies' in order to allocate blocks to a consortium rather than an individual company. Blocks were also allotted to companies desirous of entering an end-use business, though they were only supposed to be allotted to those already 'engaged in' the end-use. A few blocks earmarked for CIL or situated close to CIL blocks were also allocated for captive use, though only remote or isolated blocks were to have been offered. No well-defined criteria were used to select beneficiaries of block allocations.

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14. A few allocations to power sector companies through tariff-based bidding for ultra-mega power plants and public sector companies were not deallocated. Overall, 204 out of 218 block allocations were cancelled.

15. Please note that references to all Acts are as they existed then — most have since been amended.

Clearly, there seem to have been serious lapses in governance in this phase of coal block allocations.[16] This is in spite of the need for transparency and objective criteria for allotment of captive mines being recognised in various committee reports in the 1990s and 2000s (Planning Commission, 1996; MoC, 2005), and the then secretary in the ministry proposing auctions in 2004.

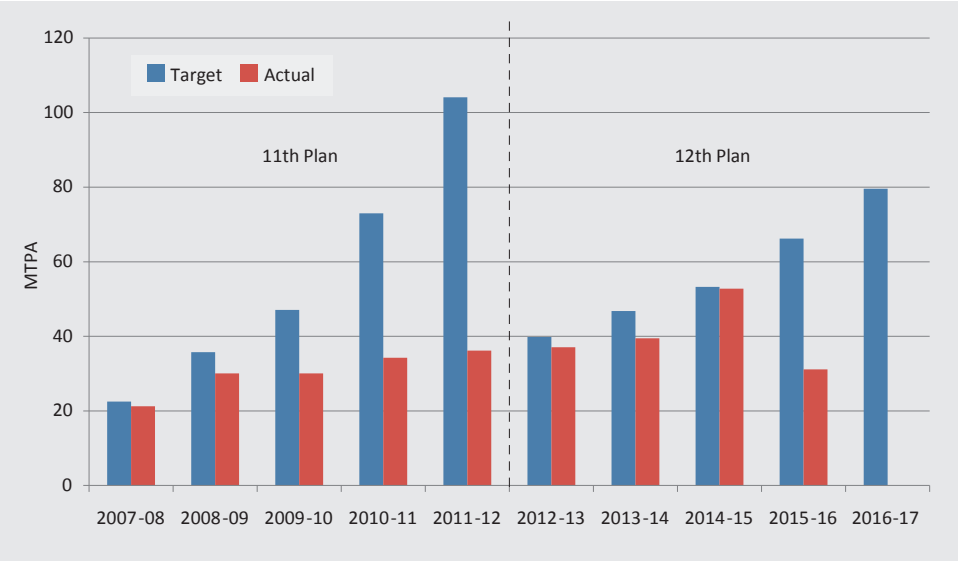
An interesting parallel with the allotment of excessive coal linkages discussed in Section 6.2 is the lack of any complaints from those who participated in the block allocation process but did not benefit from it. For example, the Supreme Court judgment says that an advertisement for the allocation of 38 blocks in 2006 received about 1400 applications, all of whom obviously did not get mines. In spite of this, there is no known record of any applicant lodging a formal complaint about the arbitrary allocation procedure or filing a law suit about it.

Ironically, in spite of, or perhaps because of, such irregularities in block allocation, these blocks did not contribute significantly to augmenting the country's coal production. The 11th Five Year Plan anticipated that captive mines would start contributing to the country's coal production in a significant way and would produce about 104 MT, or about 15% of the country's production of coal, in 2011–12. However, actual achievement was much lower at only 36 MT. As a result, the 12th Five Year Plan significantly lowered its expectations from captive coal blocks. In spite of this, production from captive blocks did not meet expectations as can be seen from Figure 6.4, and they continued to contribute just around 7% of India's coal production.[17]

16. As of August 2016, a Supreme Court monitored investigation by the Central Bureau of Investigation into irregularities in these block allocations was ongoing. Some big industrialists as well as senior bureaucrats have been charge-sheeted.

17. Production from captive blocks whose allocations were not cancelled (and which were reallocated) was just 14.1 million tonnes in 2015-16 as against 42.3 million tonnes in 2014-15, i.e. more than 65% lower (CCO, 2016). Given this situation, it appears highly unlikely that captive blocks will be able to produce anywhere near the target of 500 million tonnes by 2020.

Figure 6.4: Targeted (business-as-usual scenario) and actual production from captive blocks



Source: (MoC, 2011; CCO, 2015; CCO, 2016).

The reason for the delay in production from captive mines is often attributed to the delays in obtaining various clearances and permits required for coal mining. While procedural delays in the clearance processes could have been one factor, it is unlikely that they were the sole, or even the major factor. For example, between 2003 and 2013, the MoC deallocated 24 blocks with about 12.5 billion tonnes of reserves, mostly because there was little progress made on developing these blocks.[18] The Government of India's Economic Survey of 2011-12 states that

> "While some of the project delays are due to exogenous factors beyond the control of the implementing agencies, in the majority of cases the delays are mainly due to a dismal record of project implementation starting from project identification and designing to undue delays in procurement (both tendering and contracting) and ineffective project monitoring"

indicating that bureaucratic delays may not be the major causes for project delays (GoI, 2012).

18. An analysis of the show cause notices given to delayed captive blocks suggests that various reasons were responsible for the delays, with both government agencies and block winners being culpable.

Indeed, some experts are of the opinion[19] that the captive blocks approach itself is sub-optimal because of various reasons such as lack of mining expertise among end-use companies, artificially small block sizing to make it consistent with the end-use plant requirements, loss of coal under such artificial (rather than natural) boundaries, and the practical difficulties of multiple end-use plants being asked to operate the same block if awarded to a consortium. Therefore, there is perhaps merit in revisiting the very approach of captive blocks.

6.3.2 Allocation of coal blocks (2015)

Following the Supreme Court's cancellation of captive block allocations in 2014[20], the government promulgated ordinances that were subsequently passed as the Coal Mines (Special Provisions) Act, or CMSPA, to facilitate the reallocation of cancelled blocks (MoC, 2015a). Based on the ordinances and Act, the government allocated around 70 coal blocks for captive consumption through auctions and allotments by early 2016. Table 6.2 describes the sequence of actions related to these captive coal block allocations.[21] The government has generally claimed that these allocations were objective, transparent and competitive; and that they will result in benefits for electricity consumers (through reduced tariffs) and coal bearing states (through large revenue flows). A deeper analysis shows that, while this process of allocations was undoubtedly an improvement over the opaque, ad-hoc and illegal allocations up to 2010, there are many serious causes for concern (PEG, 2015; CAG, 2016).

The CMSPA, along with associated amendments to the Coal Mines (Nationalisation) Act, or CMNA, and the Minerals and Mines (Development and Regulation) Act, or MMDRA, address the illegalities pointed out by the Supreme Court and now empower the Central Government to allocate mines to any company, including joint ventures and state government PSUs.[22] Moreover, these mines can also be given for commercial mining to any (public or private) company. The CMSPA defines the allocation process for all the mines which were cancelled — essentially by allotting

19. These opinions were expressed at a roundtable organised by Prayas (Energy Group) in December 2014 on the future of the coal sector (PEG, 2014b).

20. The government amended the MMDRA in 2010 to mandate allocation through auctions to the private sector, and made an attempt to auction some blocks for captive use between 2010 and 2014. However, it did not attract any interest.

21. About ten mines have been allotted to state owned PSUs for commercial mining in August 2016. These are not covered in this analysis.

22. Note that the CMSPA applies only to the 200-odd blocks whose allocations were cancelled, while the CMNA and MMDRA apply to all coal mines in India and hence have a much wider scope.

mines to public sector companies or by auctioning them to any company — for two kinds of end-uses, namely power and non-power (which includes all the other sectors such as steel, sponge iron and cement).

Table 6.2: Sequence of events related to coal block allocations (2015)

Month	Action
Oct-2014	Coal Mines (Special Provisions) Ordinance, 2014 promulgated
Nov – Dec 2014	Rules and procedures under the Ordinance
Dec-2014	Coal Mines (Special Provisions) Bill introduced in Parliament (doesn't pass)
Jan-2015	Coal Mines (Special Provisions) Second Ordinance, 2015
Jan – Feb 2015	First two tranches of coal block auctions
Mar-2015	First tranche of coal block allotment
	Coal Mines (Special Provisions) Act, 2015 passed after bill re-introduced
July – Aug 2015	Third tranche of coal block auctions
Nov – Dec 2015	Fourth tranche of block auctions announced and subsequently cancelled

The auction of mines for the non-power sector was based on a simple 'forward bidding' process where companies would bid the amount they were willing to pay the corresponding state government for every tonne of coal extracted, and the highest bidder would win the block. For the power sector, the situation is a little more complex. Here, the applicants engage in 'reverse bidding', i.e. bidding below a ceiling price (again in ₹ / tonne), with the lowest bidder winning the block. The significance of the winning bid is that the bid amount (plus a fixed amount of ₹ 100 / tonne) would be used as the 'run-of-mine cost of coal' to compute the energy charge component of the electricity tariff for electricity produced from coal mined from the block. The bidding rules permitted the winning bid to be negative, i.e. the energy charge would be calculated using ₹ 0 / tonne (plus the fixed amount of ₹ 100 / tonne) as the cost of coal and, in addition, the block winner would pay the (absolute value of the) bid amount (plus the fixed amount of ₹ 100 / tonne) to the corresponding state government per tonne of coal extracted. For example, if a company won a block with a negative bid of, say, ₹ 500 / tonne, it would effectively pay the corresponding state government ₹ 600 / tonne while using only ₹ 100/ tonne as the cost of coal to compute the energy charge.[23] The auction process

had additional conditions such as eligibility conditions which tried to match the reserves in the coal block to the requirements of the end-use plant, and conditions that the block winner had to meet after winning the block.

The block allotment process (for public sector companies) was much simpler with very few conditions to define eligibility and a few lax criteria by which the winner of a mine would be decided. The energy charge used to compute electricity tariff for such power sector allottees would be the fixed amount of ₹ 100 / tonne plus the actual cost incurred in mining and processing the coal, subject to approval by the corresponding power sector regulator.

A detailed analysis of the relevant laws (CMSPA, CMNA, MMDRA and the Coal Bearing Areas Act), template tender documents, template contract documents, the process of allocations up to August 2015, and results of allocations reveal many legal, regulatory and procedural concerns (PEG, 2015). A summary of these concerns is provided below.

1. Legal concerns:

- Proviso (b) of clause 11A of the MMDRA defines the conditions under which a mine may be allocated without going through the auction process. This proviso in the MMDRA of 2010 indicated that blocks could be allocated to companies without auctions if they were either government companies or if the block was meant for a power generator who had won a tariff-based bid, such as Ultra-mega Power Plants (UMPPs). The 2015 amendment to this proviso introduces the word "or" at a crucial location which was not present in the MMDRA of 2010, as shown in Table 6.3. This curious introduction of the word at a crucial location in an important legal clause potentially enables the clause to be interpreted so that mines can be given to any company (including private companies) for any end-use without going through the auction process, and hence, potentially permitting discretionary allotments of mines even for commercial mining.

23. It can charge consumers for other components of the variable charge such as transport cost, coal handling charges, taxes, levies etc.

Table 6.3: Proviso to Section 11A in MMDRA 2010 and as amended by CMSPA 2015

MMDRA 2010	As amended by CMSPA 2015
Provided that the auction by competitive bidding shall not be applicable to an area containing coal or lignite —	Provided that the auction by competitive bidding under this section shall not be applicable to an area containing coal or lignite—
(a) where such area is considered for allocation to a government company or corporation for mining or such other specified end-use;	(a) where such area is considered for allocation to a government company or corporation or a joint venture company formed by such company or corporation or between the central government or the state government, as the case may be;
(b) where such area is considered for allocation to a company or corporation that has been awarded a power project on the basis of competitive bids for tariff (including UMPPs).	(b) where such area is considered for allocation to a company or corporation **or** that has been awarded a power project on the basis of competitive bids for tariff (including UMPPs).

- Clause 21 of the CMSPA says that the government can use the Coal Bearing Areas Act (CBAA) to acquire land for allocated captive coal blocks. But clause 11 of the CBAA allows the government to vest coal bearing lands acquired under CBAA only in government companies. Thus, there seems to be a legal ambiguity if the government chooses to use the CBAA to acquire land for mines allocated to private companies.

- The government pushed the CMSPA (including amendments to CMNA and MMDRA to enable commercial mining, among other things) through the Parliament in March 2015, citing urgency of passing the legislation in order to ensure continuity of coal production from captive mines so as to not jeopardise the country's energy security. However, the reality is somewhat different. Only 42 of the 204 blocks whose allocations were cancelled were producing coal or about to produce at the time. Moreover, the government had cited in court that CIL was capable of taking over production from these 42 blocks even if they could not be allocated by 31st March 2015. Thus, there was perhaps no urgency to push through legislation even for these 42 blocks, leave alone the 204 cancelled blocks or indeed for all blocks in the country as achieved by amending the CMNA and MMDRA. As it turns out, even by mid-2016 — over a year after the government used the argument of urgency to get the bill passed by Parliament — only 35 of these 42 blocks have been allocated and a mere 12 blocks are either producing or

about to produce (PIB, 2016b). So, it does not seem to have been necessary to rush through legislation with some sweeping changes, even as other serious problems with the coal sector such as coal allocation, regulation, pricing and market structure were left untouched. Wouldn't it have been better to introduce minimal legislation to address the issues related to the 42 blocks and undertake a more deliberative and consultative approach to draft a comprehensive legislation to overhaul the Indian coal sector?

2. **Regulatory complexity:** One of the intentions of the block allocations to the power sector through reverse bidding or allotment was that consumer electricity tariffs would come down because of access to cheaper coal. However, it is not clear if this objective would be achieved or whether it would only result in the sector being swamped in more regulatory and legal disputes.

   - Tariffs of existing Power Purchase Agreements (PPAs) governed by state regulatory commissions can be revised as envisaged by the CMSPA only after they receive directives to this effect from the corresponding state governments. However, with the exception of Madhya Pradesh, it seems that no state government has issued such a directive to their regulatory commissions by mid-2016 — over a year after the original allocations were made. The central government has issued a directive in this regard to the CERC and sent letters to state governments requesting them to issue similar directives. But regulatory commissions of Karnataka, Punjab, Rajasthan and West Bengal — all of which are likely to purchase power from power plants that have been allocated one of the 42 producing or about-to-produce mines — have confirmed, in response to Right to Information applications, that they have received no such directive from their state governments. As a result, no regulatory commission other than the Madhya Pradesh commission has issued tariff revision orders consistent with the objectives of the CMSPA.

   - Some power sector block winners did not have PPAs when they won the blocks, but hoped to enter into them by participating in future bidding rounds. The auction process for all power sector blocks auctioned until mid-2016 had already been completed before April 2015. After the process was completed, the government amended the bidding guidelines for power procurement by distribution utilities in April 2015, suggesting that regulators should cap fixed charges[24] of future power procurement, if the power is being produced from coal mined from allocated coal blocks. This

was presumably done with the intention that bidders who have won blocks based on very aggressive bids do not make up their losses by increasing the fixed charge component of the tariff. Since this guideline was issued after many blocks had been auctioned to the power sector, it has resulted in a lawsuit in the Delhi High Court[25] against such a post-facto move. While the government's intention of amending the power purchase guideline may be justifiable, the sequence of events suggests that it had not thought things through sufficiently when it rushed to pass legislation and auction blocks, with the result that it is now fighting a case and unable to auction further blocks to the power sector.

3. **Other weaknesses and concerns:** There were many other weaknesses and concerns in the 2015 coal block allocation process, some of which are described below.

   - The criteria for allotting blocks to public sector applicants were extremely weak. There is no requirement for a minimum investment in the end-use plant, there is no matching of end-use plant capacity with the block's coal reserves, and there is no objective way of selecting among multiple applicants. Thus, these allotments are effectively discretionary.
   - Some aspects of the auction design such as allowing multiple bids from different end-use plants of the same company and selecting only the top 50% for the financial bidding round for the first two auction tranches[26] effectively reduced competition (CAG, 2016). For example, three of the five technically qualified bidders, i.e. 60% of the technically qualified bidders, for the Sarshatalli block were from the same group.
   - Though these allocations are more transparent than the completely opaque allocations that preceded them, many critical details remained unpublished. These include details of mines to be allotted to public sector companies, details of end-use plants that applied for the blocks and won them, the final signed contracts with mine winners, and the reasons why some blocks were not allocated.
   - Monitoring of the quantity and quality of coal produced from allocated mines is important for various reasons such as adherence to the mining

24. Power tariffs have two components — fixed and variable charges. Chapter 2 on thermal generation explains this in greater detail.

25. The suit was filed by Monnet Power Ltd. which has won the Utkal C block.

26. This lacuna has been partially addressed in subsequent bidding rounds.

plan, determining electricity tariffs and calculating revenue due to states. However, the legal contracts have very weak provisions for monitoring of coal production, and it is highly unlikely that the Coal Controllers' Organisation (CCO), which is responsible for these functions can do justice to it.[27]

- The coal mining contracts provide for 'arrangements' and 'diversions' of coal mined from a captive block, with very few checks and balances (other than central government approval for arrangements) about what these arrangements and diversions can be. While the government's intentions in introducing these provisions may have been to encourage optimisation of coal usage and transportation, they are not reflected in the corresponding legal or contractual clauses, thus potentially defeating the purpose.[28]
- There are a large number of court cases regarding these block allocations, with some estimates indicating as many as 85 cases filed for the 70 allocated blocks (Sharma A., 2016). Some of the reasons for the law suits include the basis for classification of blocks into various end-uses and allegedly arbitrary cancellation of bidding results for some blocks (Delhi HC, 2015, pp. 48-57; Mathur, 2015).
- Many analysts believe that the bidding for blocks in the first two rounds has been extremely aggressive and these blocks are likely to become unviable for the winners (ICRA, 2015; HDFC securities, 2015). This is not good news for a sector that is already under severe financial stress.

After the aggressive bidding for the first two rounds of block auctions, interest in acquiring coal blocks has waned considerably. The third round of auctions held in July–August 2015 attracted an average of less than four bids per block with winning bids much lower than the first two rounds. The government's attempt at a fourth round of auctions in December 2015 fared even worse, as it was cancelled for lack of sufficient interest (PTI, 2015). The initiative to allot blocks to state government public sector units (PSUs) for commercial mining has also attracted tepid interest. Eight blocks were offered to host-state owned PSUs, of which three of them attracted no applications at all, and five attracted just one application each (MSTC, 2016a).

27. See Section 6.4.2 for details.

28. Surprisingly, the government refused to provide information about end-use plants, arrangements and diversions of allocated blocks even in response to an application under the RTI Act citing commercial confidentiality, though none of these should involve any commercial considerations.

The eight blocks offered to non-host states fared even worse, with as many as six blocks attracting no applications at all, and the remaining two blocks attracting just two applications each (MSTC, 2016b). This suggests a waning interest for coal mines among private and public sector companies. Indeed, production from captive blocks appears to have fallen by as much as 34% in 2015–16 compared to 2014–15, with reports suggesting that block winners may find it better to not mine from them (Coal Insights Bureau, 2016). Perhaps, it is safe to conclude that the latest attempt to allocate blocks to non-CIL companies has also come unstuck.

6.4 The missing reforms

Though the previous sections have critiqued the attempts at reforms in the coal sector, it is not to say that the coal sector was performing well before those reforms. Indeed, the sector had and has many serious weaknesses relating to market structure, pricing, regulation, law and order, and socio-environmental issues (PEG, 2013). However, the reforms of the past two decades have largely tended to ignore many of these problems, in spite of multiple government appointed committees highlighting them over the years. Some of these 'missing reforms' are elaborated in this section.

6.4.1 Coal India Limited

CIL is the world's largest coal producer and produces about 80% of coal produced in India (CIL, 2015a). In this situation, the efficiency and accountability of CIL is critically important for a healthy and effective coal sector. Unfortunately, there are sufficient grounds to question CIL on both these counts.

CIL's productivity and efficiency levels are generally considered below international standards. For example, in 2007, India (with CIL as the dominant player) produced less than 5,000 tonnes per person per year from its open cast mines, while the corresponding number was greater than 20,000 for Australia and USA, and between 7,000 and 10,000 for South Africa and China (CCO, 2008; Energy Edge, 2007). The productivity of underground mines in India is even worse at less than a tonne per person-shift, compared to about 13 tonnes per person-shift for open cast mines. Questions have also been asked about the utilisation of the capital intensive Heavy Earth Moving Machinery with CIL, reinforcing concerns about its efficiency (CAG, 2012).

The quality and quantity of coal supplied by CIL has been questioned for the best part of 30 years. Coal consumers had complained of poor quality and inadequate

quantity of coal even in the 1980s, and the issue continued to be a sore point into the 2000s (Planning Commission, 1985; MoC, 2005). More recently, many state-owned power generating companies from states such as Maharashtra, West Bengal, Madhya Pradesh and Gujarat complained to the Competition Commission of India (CCI) about CIL abusing its market power to supply coal of inferior quality and insufficient quantity. They complained that CIL's Fuel Supply Agreements (FSAs) are one-sided in nature and do not provide effective avenues for resolving grievances regarding the quality or quantity of coal supplied. Upon investigating these complaints, CCI issued a series of orders where it broadly held CIL guilty of abusing its monopolistic position by supplying inferior quality of coal and not providing its consumers a means of addressing this problem (CCI, 2013; CCI, 2014a; CCI, 2014b).[29] Subsequently, CIL has initiated some steps towards better accountability for coal quality. It is now exploring the possibility of third party sampling of coal quality based on an empanelled set of coal quality samplers (CIL, 2014a), and has started publishing some details about sampled quality and quantity of coal supplied to some consumers (CIL, 2014b; CIL, 2015b).

Interestingly, though CIL is practically a monopoly coal supplier, coal pricing was decontrolled in 2000 thus letting CIL (and other companies such as Singareni Collieries Company Ltd.), in principle[30], to set its own prices with the latest price increase from CIL occurring in May 2016, even as international coal prices were highly suppressed (CIL, 2016).

Another interesting aspect about CIL is that most of the coal it supplies is typically not washed or even crushed to a reasonable size, thus increasing transportation and handling costs, though there have been plans to augment washery capacity since about 2011. In 2016, CIL once again reiterated its commitment to setting up washeries and delivering crushed coal to power plants (PTI, 2016).

These problems with CIL have been highlighted to varying degrees in multiple reports over the last forty years or so (Planning Commission, 1974; Planning Commission, 1979; Planning Commission, 1996; MoC, 2007b; GoI, 2011b). Unfortunately, there has been little, if any, serious action to address these concerns, or to consider the suggestions made by the various committees.

29. These orders were set aside by the Competition Appellate Tribunal in May 2016 on purely technical grounds (COMPAT, 2016).

30. In practice, there are some checks on CIL abusing its monopoly pricing power as the government holds the majority stake in the company.

6.4.2 Regulation of the sector

For reasons best known to the government, it has been very reluctant to give up control of the coal sector by appointing an independent and empowered regulator for it, though multiple committees have recommended this for the last two decades (Planning Commission, 1996; MoC, 2007b). As a result, there has been poor oversight of mining practices, productivity and contractual adherence, with the government unable to effectively play the role of regulator while also being the owner of the largest coal company.

Setting up such a regulator[31] can, with the right institutional design, potentially improve the accountability of a sector dominated by a large public sector monopoly though sobering experience from other sectoral regulators should be considered while designing the regulatory institution.[32] The regulator will also have an important role to play if the sector is opened up and multiple miners sell coal to consumers.

Currently, the agency expected to perform some of the 'technical' regulatory functions such as overseeing coal production and mine closure is the Coal Controllers' Organisation (CCO) which is a part of the Ministry of Coal. However, the CCO is severely under-staffed and ill-equipped to carry out its functions.[33] The CAG and the Parliamentary Standing Committee on Coal and Steel have come down heavily on the inability of an agency as important as the CCO to perform its duties (CAG, 2012; Parliamentary Standing Committee on Coal and Steel, 15th Lok Sabha, 2013)[34]. In response, the annual reports of 2012–13, 2013–14 and 2014–15 of the Ministry of Coal have stated, respectively, that it has commissioned a

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31. The regulator for the coal sector need not be a separate regulator — a single suitably integrated regulator for different energy sub-sectors can be considered. But this issue is not dwelt upon in this book.

32. See "Chapter 2, Too good to be true: The story of thermal generation"; "Chapter 5, Electricity distribution: On square one, even with reforms after reforms"; and "Chapter 7, Natural gas: Running on empty" for weaknesses of regulators as they exist in the power and natural gas sectors.

33. In March 2016, the Government of India delegated some functions of the CCO (related to coal quality and mine inspections) to respective state governments concerning some mines. It is not clear whether the corresponding state governments would have the requisite capacity or expertise to fulfil these functions.

34. Here are a couple of quotes from these reports to indicate the seriousness with which they view the situation:
"CCO did not have adequate strength or men-in-position for effective monitoring of coal blocks … The Ministry accepted (February 2012) that there was a need to strengthen the CCO, Kolkata and stated that a proposal for creation of additional posts was under consideration" and
"The Committee fails to understand as to how without having adequate manpower, the organisation can carry out inspection for ascertaining quality in selected mines. It will be difficult to undertake regular inspections to ensure compliance with specific orders relating to coal quality and resolving statutory complaints".

report from the Indian School of Mines on the CCO's functioning (MoC, 2013b, p. 17); that it has received the commissioned report (MoC, 2014, p. 17); and that it is examining the received report (MoC, 2015b, p. 24). However, the issue seems to have since been forgotten as the annual report for 2015–16 is silent about improving the effectiveness of the CCO (MoC, 2016). Therefore it seems that the country has a long wait ahead to have an effective technical regulator who can oversee functions such as coal mine closure and coal production.

6.4.3 Socio-environmental concerns

Mining, processing, transportation and combustion of coal can lead to significant environmental impacts in the form of air and water pollution. Coal mining is also fairly land intensive which results in displacement of communities and disruption of livelihoods. In India, it also has significant impact on forests and bio-diversity.

There is very little systematic data to be able to assess the impacts of coal mining and associated industries on the resettlement and rehabilitation (R&R) of those who have been displaced or have lost their livelihoods. However, the little data that is available suggests that the record of coal mining companies has been poor in this regard. An assessment of the R&R of those displaced by the various projects in the Singrauli region, a major coal-based energy hub, shows that only 36% of the affected families were provided with alternative livelihoods, and only 55% were provided with resettlement plots for housing (Sharma & Singh, 2009). Another assessment finds that CIL provided jobs to only 36% of the displaced in the 1980s, and to a mere 10% of the displaced in the 1990s due to increased mechanisation (Fernandes, 2007). Actions such as cancelling villagers' and tribals' rights over forests enshrined by the Forest Rights Act further reinforce the notion that the government is not keen to address these social issues with the requisite sensitivity (Sethi N., 2016).

The record of mitigating the environmental impacts of coal mining and associated industries is poor. Air pollution data from the Central Pollution Control Board (CPCB) shows that 19 out of 21 monitoring stations near coal mines and coal-fired power plants recorded yearly average Respirable Suspended Particulate Matter (RSPM) concentrations above permitted norms in 2010 (CPCB, 2012). The average concentration at these locations was 1.9 times the norm, while three locations (near Jharia in Jharkhand and Chandrapur in Maharashtra) recorded concentrations over 3.5 times the permissible limit. Such high presence of RSPM leads to serious respiratory and other illnesses severely impairing people's lives.

Other reports confirm the poor environmental management regime prevalent in the country. Kohli and Menon (2009) state that only few of the cleared mining projects submit project monitoring reports as required, and only a few among those who submit reports comply with the required practices. The CAG audit of CIL's corporate social responsibility activities shows significant non-compliance in obtaining environmental clearances for project expansion, backlogs in land backfilling and reclamation, poor topsoil restoration, and lack of environmental system management certification (CAG, 2010). This reality points to severe weaknesses in the socio-environmental governance systems of coal and allied sectors.

Coal mining is a hazardous profession[35]. Unfortunately, indicators related to worker safety in India do not provide cause for cheer. The CAG pointed out that only 2% to 7% of employees of CIL contractors were subjected to regular medical check-ups though it was mandatory for all (CAG, 2010). Worker fatalities and fatality rates at CIL increased between 2011 and 2013, though they fell in 2014 (CIL, 2014c).

With the plans to increase coal production in India, the magnitude of these problems is also likely to increase. Therefore, if the government does not take steps to address these pressing concerns, it should not be surprised if it comes across increasing resistance to coal mining in the affected areas.

6.4.4 Other issues

1. **Extractable resource identification:** India's coal resources are typically classified into three categories, namely indicated, inferred and proved. Of these, there is a high probability that the quantity of proved category resources exist underground. However, this does not indicate how much of these reserves are technically and commercially extractable (TERI, 2011). This uncertainty around extractable coal reserves increases the risks around energy sector planning. Though multiple reports have recommended acceleration of exploration and identification of extractable coal reserves with greater certainty (Planning Commission, 1974; Advisory Board on Energy, 1985; MoC, 2005), so far only part of CIL's coal resources have been mapped according to internationally accepted standards such as the United Nations Framework Classification (UNFC).

35. The report of the working group on occupational safety and health for the 12th five year plan states that coal mining is "recognised as one of the most hazardous peacetime occupation[s]".

2. **Law and order issues:** The coal sector has long been beset with law and order problems, with reports of illegal mining, 'mafia' control of various mining operations, and diversion of coal to other uses than intended. In fact, the Parliamentary Standing Committee on Coal and Steel had expressed its frustration regarding the inability of the government to deal with this issue, by stating that the Ministry of Coal was "absolving itself from the responsibility of curbing illegal mining", and that "the Committee feels that Ministry/Coal PSUs have utterly failed to discharge their responsibilities as far as stopping of illegal mining is concerned." (Parliamentary Standing Committee on Coal and Steel, 15th Lok Sabha, 2012). A more recent Parliamentary Standing Committee report indicates that though some measures based on greater use of technology have been initiated, the problem remains (Parliamentary Standing Committee on Public Sector Undertakings, 16th Lok Sabha, 2016).

Thus, the coal sector's reforms of the past two decades have neglected many fundamental issues such as improving the efficiency of CIL, effective regulation of the sector and addressing socio-environmental concerns.

6.5 Conclusion and lessons

The T L Sankar led expert committee on a roadmap for coal sector reforms stated in the first part of its report in 2005 that "the essential weaknesses of the sector have remained almost unchanged during these three decades" (MoC, 2005, p. 1). It is perhaps fair to say that this statement largely holds true even a decade later. The sector remained neglected and outside the public eye until about 2012, when the coal shortage and breaking of the 'coal-gate' scandal brought it suddenly into the limelight. The analysis in this chapter suggests that there are a few common reasons for these persistent problems as described below.

Weak policy formulation: Many policies have been drafted in an ambiguous manner permitting either multiple interpretations or providing very weak checks and balances. The primary example is the NCDP, which allowed multiple contradictory interpretations, leading the country to the severe coal shortage of 2012, and which still provides a weak policy framework for coal allocation. The 'policy' governing the awarding of captive coal blocks in the first regime is another example, since it contained almost no objective criteria for selection among multiple applicants, and contained no checks and balances whatsoever to ensure that the benefits of such coal block allocations would accrue to the citizens of the country. Even recent

policy changes in the sector have ignored many fundamental issues and appear to have many ambiguities, which have led to multiple litigations and a general waning of interest.[36]

Vested interests: The presence of various 'mafias' and illegal mining has long been a thorn in the coal sector's side. However, the issue has not received sufficient attention until recently, allowing such interests to get more entrenched into the sector. Beyond the mafias and illegal mining, there are also indications of the presence of vested interests in other aspects of the coal sector value chain. The entire saga of the first regime of captive coal block allocations and the ongoing Supreme Court monitored investigations into these are one indication of all not being well in the coal sector. The silence of those who did not succeed in getting linkages or captive blocks, in spite of the severe competition for them, is another strong indicator of everything not being above board in these processes.

Weak institutions: The lack of commitment to a robust institutional setup to develop policies, implement them and oversee the sector is another major reason behind the sector's weaknesses. The lack of an empowered regulator for the coal sector, despite many recommendations for such an institution, is illustrative of such a lack of commitment. Another very good example of this is the CCO. Though the CCO is expected to perform a set of crucial functions such as overseeing mine operations and their closure, and collect and report coal sector related data, it is extremely ill-equipped to fulfil its role. Therefore, it is perhaps not surprising that illegal mining, improper mine closure and so on are a reality of the Indian coal sector. A third example of weak institutions relates to socio-environmental monitoring and compliance, with state pollution control boards either unable or unwilling to hold miners accountable to responsible mining practices.

Lack of proactiveness: Effective policy formulation and management requires proactive measures. However, the coal sector is characterised by its reactive nature. The NCDP was drafted only after the Supreme Court ordered the government to draft a policy for allocation of coal. The problems related to the first regime of awarding captive coal blocks came to light only after a CAG report, and action was taken only after 17 years of awarding blocks. Issues such as the inefficiencies of CIL and the lack of evacuation infrastructure did not get the attention they deserved until domestic coal shortage reached crisis levels. All these suggest that the coal

36. Economic factors could also have played a role in the loss of interest.

ministry was happy to react to external developments rather than set the agenda for the coal sector to support a vibrant energy sector.

Transparency: This has been a major weakness of the coal sector for a long time. Unlike the Electricity Act, there is no legal mandate for the various coal sector agencies to *suo-motu* publish information. In the past, agencies such as the Ministry of Coal (MoC), CIL, the CCO and the state pollution control boards published very little information. More recently, there has been an improvement in the information published by the MoC and CIL, though there is still significant room for improvement in proactive disclosure of information.

Lack of comprehensive approach: The coal sector is closely related to other sectors such as power, railways, iron and steel, and environment and forests. However, the various problems seen in the sector, such as the lop-sided development of the coal and power sectors, the slow development of key evacuation links, and the continuing tussles around environmental clearances and compliances, indicate that these sectors do not function as cohesively as they should.

Considering that the government has many plans for the coal sector through measures such as auctioning coal linkages, rapidly increasing production and introducing commercial mining, it is hoped that the findings listed above are taken cognizance of, so that the sector can contribute effectively to India's sustainable and equitable development.

7
Natural gas: Running on empty

REFORM, v. A thing that mostly satisfies reformers opposed to reformation[1]

7.1 Introduction and overview

Natural gas plays a small role in India's energy sector, accounting for approximately 6.5% of India's commercial energy supply in 2015, as opposed to about 24% worldwide. This is a result of limited domestic reserves and poor access to modern energy sources.[2] India accounts for about 0.8% of the world's proven reserves and annual production of natural gas. Thus, imports form over 45% of the natural gas consumed in India. (MoPNG, 2016, pp. 10, 148, 188)

However, consumption of natural gas is expected to pick up rapidly in the coming years due to growing economy, adoption of cleaner cooking fuels, improved electricity supply quality, and greater emphasis on mitigation of local air pollution and global climate change. Natural gas is seen as a transition fuel to a low carbon economy as its combustion emits roughly half the greenhouse gases as coal for the same level of power generation, and about 70% of that of oil for transportation. Natural gas power plants have shorter start-up times than coal based power plants and are expected to play an important role in generation

1. From Devil's Dictionary by Ambrose Bierce.

2. 21-22% of Indian households do not have access to electricity and 67% depend on solid (biomass) fuels for cooking/heating.

balancing as large variable renewable energy capacity is added to the electric grid.[3] A vast majority of Indian households do not have access to clean cooking fuels, and LPG (liquefied petroleum gas)[4] and piped natural gas are expected to play an important role in addressing this situation. In addition, natural gas has some important competing non-energy uses such as in fertilizer production.

Natural gas policies have focused largely on increasing energy security, reducing the import bill and increasing uptake of natural gas to address household air pollution. To this end, policies have attempted to increase domestic production and promote consumption of gas through pipelines and distribution networks. These policies are inextricably linked to natural gas prices, since prices determine economic feasibility of extracting gas that is discovered through exploration as well as affordability of that gas for consumers. With the advent of liberalisation came a push towards greater privatisation and lower subsidies. In the context of increasing private participation, and in the absence of a national gas market, policies have attempted to discover an appropriate price to encourage both production and consumption of natural gas.

In this chapter, we focus on implementation of an exploration and production licensing policy called New Exploration Licensing Policy (NELP) that was introduced in the late 1990s to boost domestic production through increased private investment. This policy was expected to partially benefit the electricity sector by increasing supply of natural gas available for power production. Apart from analysing the impact of NELP on domestic natural gas production, we also examine marketing and pricing policies governing gas produced under NELP. Both availability and price of natural gas have had a significant impact on power generation. Since the focus of this book is on reforms impacting the power sector, we do not delve into transportation and distribution aspects of the natural gas sector even though they play an important role in development of a national gas market.

Several recent changes in the sector make this analysis relevant at this time. The search for an optimal exploration licensing regime continues as revenue sharing contracts and open acreage licensing are expected to be operationalised soon (see

3. Much of the current gas based power generation is from combined cycle units which are more suited to base load generation rather than to provide peaking power. Gas based power generation that could come up for balancing variable renewable energy is likely to be from open cycle units which can ramp up and down quickly as needed. However, open cycle units have lower energy conversion efficiency.

4. About a fifth of the LPG consumed in India is derived from raw natural gas through the process of fractionation. The rest is produced from crude oil. (MoPNG, 2016, p. 40).

Section 7.13). A revised gas pricing formula has been put in place, while pricing freedom is proposed for difficult-to-explore fields. In addition, there have been recent efforts to revive stranded gas-based power generation to meet the country's energy shortage as well as generation balancing needs.

7.2 Brief overview of reforms

Oil and gas reserves are geologically co-located, hence reforms for exploration and production of oil and natural gas have happened in tandem. Together, oil and gas account for a significant share of India's energy basket, and since a significant portion of this is imported, it was recognised right after India's independence that domestic production of oil and gas needs to increase in order to improve energy security and reduce import dependence. Several attempts were made to increase exploration and production (E&P) through National Oil Companies (NOCs), i.e., Oil and Natural Gas Corporation (then Oil and Natural Gas Commission, ONGC) and Oil India Limited (OIL)[5]. Hydrocarbon blocks offered during this time are referred to as nomination blocks, referring to the blocks being assigned to ONGC and OIL on a nomination basis. E&P activities received a huge boost in the early 1970s with significant discoveries of oil and gas off the western coast of India, called the Bombay High.

During the late 1980s, bad management practices were followed by ONGC in Bombay High wherein many wells were "flogged" to produce oil at a high level even though production was levelling off. Additional oil thus produced was at the expense of long-term potential of the reservoirs. (Thakurta P. G., 1991)

In response to this and in order to manage increasing private participation, the Directorate General of Hydrocarbons (DGH) was set up in 1993 under the Ministry of Petroleum and Natural Gas (MoPNG) to regulate various aspects of upstream oil and gas activities such as licensing, safety, development, conservation and reservoir management.

Efforts to involve private participation in E&P began in the late 1970s with three rounds of exploration bidding between 1980 and 1986 which weren't successful in attracting significant interest or finds. Subsequently, between 1992 and 1993, small and marginal fields that were discovered by NOCs were offered for development

5. OIL, which began as a private company that took over E&P operations that began in British India, was nationalised in 1981.

to private operators over three bidding rounds. A further six rounds of bidding were offered for exploration between 1991 and 1995 and onwards during which 27 exploration blocks were awarded. Collectively, these blocks are referred to as pre-NELP blocks. (DGH, 2016, p. 21)

Operations in a pre-NELP exploration block are governed by production sharing contracts (PSCs), where the Government of India (GoI) receives a share of the profit based on the fiscal terms quoted in the winning bid. In addition to a share in profit, the GoI has a carried interest of 30%.[6] Once a discovery is made, the GoI or its nominee has the option to convert the carried interest into a working interest by contributing to development and production costs in return for an equal share of the profits from the sale of hydrocarbons. The last exploration round in 1995 was a joint venture round. In this round, the contractor had to form a joint venture with ONGC or OIL who could hold between 25% and 40% of shareholding in the venture, called the participating interest, thus contributing to exploration, development and production costs in proportion to their shareholding and receiving the same share of profits. In addition, gas produced under pre-NELP could only be sold to the public sector company — Gas Authority of India Limited (GAIL).

In spite of these efforts, only a small portion of India's sedimentary basin was explored by 1999. Exploring and exploiting India's unexplored reserves requires deployment of sophisticated technology and global best practices. Hence, the objective of reforms in hydrocarbon exploration and production has been to attract risk capital[7], geological expertise, state of the art technologies and management practices.

In 1994, a study group of oil industry officials headed by Sundararajan, then Chairman of Bharat Petroleum Corporation Limited (BPCL), was formed to develop a long-term perspective plan up to 2010 to recommend measures for restructuring the hydrocarbon sector, and to suggest a system to ensure free and fair competition in order to protect interest of consumers in a deregulated scenario. The Study Group suggested that measures need to be taken to increase participation of private players who can bring deep water drilling technology, increased competition and efficiency to the sector. In its report titled *Hydrocarbon Perspective: 2010 — Meeting the Challenges*, the study group said the following about domestic gas production:

6. Under the pre-NELP policy, NOCs nominated by the GoI are the licensees. They pay royalties and exploration license fees and, in return, are entitled to 30% carried interest after commercial discovery without contributing to past exploration costs. When this carried interest is converted to working interest or participating interest, NOCs bear that proportion of E&P costs and receive the same proportion of the production.

7. Risk capital refers to capital that is employed in high-risk, high-reward projects.

> "Based on India's proven reserves, the availability of Natural Gas is not expected to go up substantially in the short run. However, so far, 80% of the acreage has not been surveyed and therefore the potential oil and gas reserves in the country have not been fully established. Steps need to be taken to induce investments to enhance the reserves in the country and to convert the current discoverable reserves into established reserves. Since exploration is highly capital intensive, private investment is necessary. Suitable policies are therefore to be initiated to attract private investment — both domestic and foreign. This will, in the long run, increase the availability of gas." (Sundararajan, 1994, p. 71)

This approach is similar to that followed for attracting private investment in hydropower and thermal power generation during what came to be known as the 'IPP era'. Refer to Sections 2.2 and 3.1.2 for more details.

Subsequently, the GoI appointed a committee called the Strategic Planning Group on Restructuring of Oil Industry (or 'R-Group') in 1995 headed by the then Petroleum Secretary Vijay Kelkar, to suggest ways to operationalise the recommendations made by the study group. The R-Group suggested a production sharing contract (PSC) based bidding of exploration blocks where a "level playing field" is created for public sector and private, domestic and international players. Based on these suggestions, the New Exploration Licensing Policy (NELP) was formulated.

7.3 New Exploration Licensing Policy (NELP)

The New Exploration Licensing Policy (NELP) was introduced in 1999 to facilitate open international competitive bidding. Under this policy, private as well as state owned oil companies would compete to secure exploration licenses under the same fiscal and contractual terms defined by a Model Production Sharing Contract that is reviewed prior to each round. This approach is different from the approach taken to introduce competition in the power and coal sectors, where competitive bidding auctions are conducted solely for private companies, whereas state owned coal companies are allocated coal mines by the government, and state owned power generators can operate in a 'cost-plus' regime. 100% Foreign Direct Investment (FDI) is allowed and there is no mandatory participation of the GoI either directly or through NOCs, i.e., ONGC and OIL. Contractors are free to sell gas produced under NELP in the domestic market at market or "arms-length determined" prices.

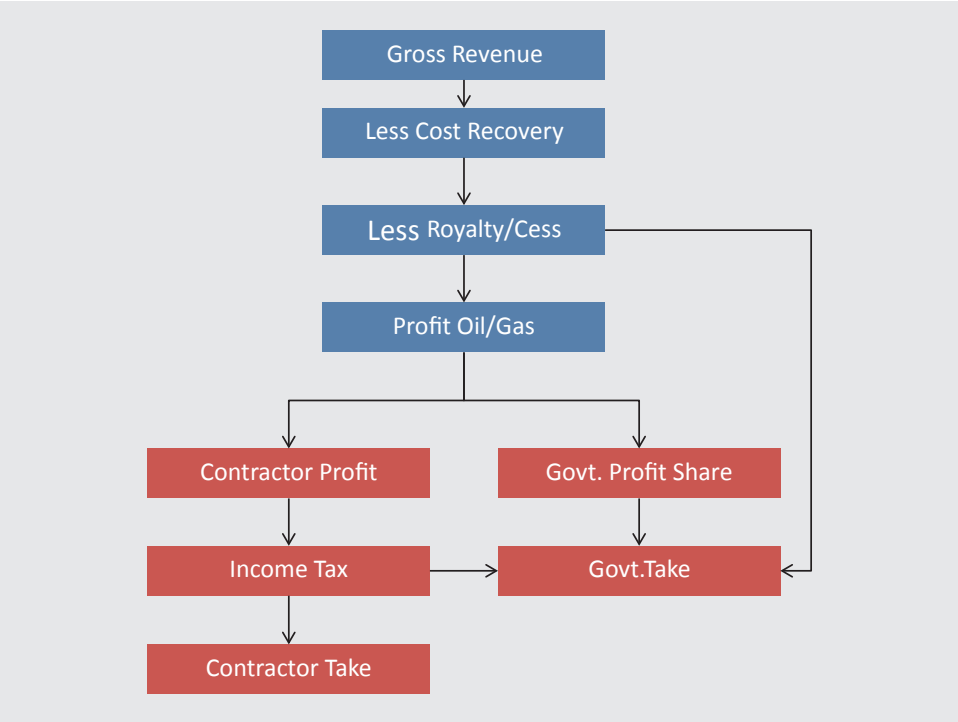
A consortium of companies typically participates in the bidding process in order to pool investment or expertise. The company or consortium with the winning bid

is the contractor and is bound by the terms of the contract once it is signed. One of the companies within the consortium is designated as the operator and carries out the E&P operations and other functions as required under the contract on behalf of the contractor.

7.3.1 The Production Sharing Contract (PSC)

The NELP contract has the notion of "profit petroleum", which is the surplus obtained from sale of oil or gas after recovering production, exploration and development costs, royalties, and other taxes (called "cost petroleum", See Figure 7.1). Fiscal terms detail out how profit is shared between the contractor and the GoI. The ratio of cumulative net income[8] and the cumulative exploration and developments costs is called the pre-tax investment multiple (IM). Profit petroleum is shared between the GoI and the contractor based on the previous year's IM according to the different IM slabs quoted in the winning bid. The more capital intensive the project, the lower the IM and usually the lower the GoI share of profit petroleum.

Figure 7.1: Sharing of profits under NELP



8. Net income = cost petroleum entitlement + contractor's share of profit petroleum (based on previous year's IM) + incidental income - production cost - royalty.

Royalty is charged at the rate of 10% of the well-head value for natural gas and 10–12.5% for oil depending on whether the area is on land or offshore.[9] During the first seven years after the commencement of commercial production, royalty is charged at half the rate for deep water areas. Cost recovery is made first for royalty/cess payments, then for production costs, then for exploration costs and finally for field development costs. Tax holiday for profits earned from production of oil and gas is available for some NELP rounds under Section 80-IB (9) of the Income Tax Act (CNBC-TV18, 2009; Pathak, 2014).

7.3.2 Oversight of E&P operations

The DGH, in its advisory regulatory role, monitors E&P activities to ensure compliance by the contractors with the terms of the PSC. E&P activities undertaken in each block are monitored by that block's Management Committee (MC) comprising two GoI nominees, typically from the DGH, and one representative each from the companies representing the contractor. The MC reviews and approves annual work programmes and budgets, commerciality of discoveries, field development plans and other aspects delineated in the PSC. The MC is chaired by one of the GoI nominees. Decisions need a positive vote from the GoI nominees and at least 70% participating interest. Ministry of Petroleum and Natural Gas (MoPNG) is the nodal ministry responsible for overall decision making and matters related to non-compliance or dispute resolution.

7.3.3 Exploration

Exploration is the process of improving geological knowledge of the area that is predicted to contain hydrocarbon reserves, thereby determining technical feasibility and economic viability of extracting those reserves. Initial exploration activities include seismic surveys that assist in detecting coarse features of sub-surface geology. A smaller area is identified for more detailed exploration if the survey data meets certain criteria. Detailed exploration involves drilling exploratory wells and the data from this phase is used to determine whether it is economically viable to extract hydrocarbons.

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9. Royalty from onshore areas goes to the state government, whereas the central government gets the royalty from offshore areas. As per MoPNG Resolution No. O-19018/22/95-ONG-DO, "half of the royalty from offshore areas is credited to a hydrocarbon development fund to promote and fund exploration related activities, such as acquisition of geological data on poorly explored basins, promotion of investment opportunities in the upstream sector, institution building etc."

Under NELP, exploration activity is split into two phases (up to three phases in earlier rounds). By the end of the first phase, at least the Minimum Work Programme that was bid needs to be completed, which includes seismic surveys and a few exploration wells. The maximum exploration period (all phases together) is typically seven years for on land and shallow water blocks and eight years for deep-water blocks, with four to five years allowed for initial exploration and three years for subsequent exploration. At the end of each phase, the contractor must relinquish those parts of the contract area that are not demarcated as discovery or development areas as per the terms of the contract.

The Minimum Work Programme (MWP) is proposed by the contractor and is one of the criteria on which the bid is evaluated. If the MWP is not completed within the stipulated time, liquidated damages equivalent to the estimated expenditure required to complete the remainder of the work can be levied. The PSCs generally allow for one extension of six months subject to approval by the Management Committee (MC), either to complete MWP or to undertake additional exploration. Under the NELP extension policy formulated in 2006, extension may be granted for an exploration phase by way of increasing bank guarantee amount and/or cash payment as liquidated damages towards the unfinished work programme. A maximum extension of 18 months is allowed in three stages. Delays that occur due to pending government approvals/permits/clearances are allowed.

7.3.4 Development and production

If oil and/or gas are discovered and potential commercial viability is determined, an appraisal programme is undertaken based on which the contractor advises the MC on whether a commercial discovery should be declared through a Declaration of Commerciality (DoC). Along with the declaration, the contractor submits all techno-economic data related to the discovery such as recoverable reserves, sustainable production levels and estimated development and production expenses. Subsequently, a Field Development Plan (FDP) is submitted for MC review and upon approval, the contractor commences development and production operations.

Typically, the exploration phase is the most risky since it may not lead to a commercially viable discovery, whereas development operations are the most capital intensive due to the large infrastructure build out.

7.4 Has NELP achieved its goals?

NELP has been hailed as a success by successive governments, particularly in annual reports of MoPNG and DGH (DGH, 2016, p. 24; MoPNG, 2014-15, p. 25). NELP has resulted in increased private participation and a significantly more open hydrocarbon sector than in the early 1990s. As of 31st March 2015, a total of US$ 25.06 billion has been invested, of which US$ 15.40 billion was spent on exploration and US$ 9.66 billion was spent on development (DGH, 2016, p. 25).

Overall, NELP auctions resulted in 91 gas discoveries in 32 blocks, of which 40 discoveries are in deep water blocks, 37 in shallow water blocks, and 14 on land (DGH, 2016, p. 94). Commercial production of gas commenced in 5 NELP blocks. The most prolific of these has been the deep water block KG-DWN-98/3 block (also called KG-D6), where production commenced in 2008–09.

22 gas discoveries from 10 NELP blocks are under development, of which KG-OSN-2001/3 and incremental production from KG-D6 are expected to contribute significantly to gas production in the coming years, at a peak of 28.5 million metric standard cubic metres per day (mmscmd) (DGH, 2015, p. 34). According to some reports, domestic gas production is expected to increase from the current 98 mmscmd to about 147 mmscmd in 2018–19 (PTI, 2015a).

However, similar optimistic projections made in the past have not fructified. The potential peak production rate of KG-D6 block alone was estimated at 120 mmscmd in 2008 when the total domestic production was around 89 mmscmd (Airy, 2008). Gas production in the KG-D6 block commenced in 2008–09 and lifted domestic production to about 143 mmscmd in 2010–11. However, there was an equally steep decline in production from the block after 2010–11 such that domestic production fell to about 92 mmscmd in 2014–15 (see Figure 7.3). Circumstances that led to this drop in production are controversial and are discussed briefly in Sections 7.7 and 7.9.

A lot was expected from the NELP regime:

- The production sharing contract was expected to strike a balance between government and investor interests, thus encouraging healthy competition.
- Increased exploration using state of the art techniques was expected to dramatically improve estimation of Indian hydrocarbon reserves resulting in greater investments in the sector and increased domestic production.
- Increased domestic production was expected to result in reliable and affordable supply of natural gas for power generation and other uses.

- The DGH was expected to enforce contracts and to ensure that the best reservoir management practices are followed and that operations are efficient and competitive.

Much of this did not happen as expected. Participation in NELP bidding has declined in recent rounds, production is far below expectations, competition is limited, major international E&P players have not entered the market, and there are several lacunae in management of E&P operations. The following sections elaborate these weaknesses.

7.5 Bidding experience

NELP bidding happened over nine rounds during which 355 blocks were auctioned, resulting in the signing of 254 contracts covering an area of roughly 1.5 million sq. km.[10] out of the total Indian sedimentary area of 3.14 million sq. km. Of the 254 blocks, 111 are on land, 62 are offshore shallow water and 81 are deep water areas. Of the 254 NELP blocks auctioned, 98 blocks are operational[11] and 156 blocks have been relinquished as of March 2015 (DGH, 2016, p. 24).

Bids under NELP are evaluated based on the exploratory work programme and fiscal package offered as well as the technical capability of the bidder. In the earlier rounds, the financial capability of the bidder was also considered. Work programme is a biddable parameter and refers to the extent of seismic surveys and number of exploratory wells to be drilled. The fiscal package includes a cost recovery factor[12], and the portion of the profit the bidder is willing to share with the GoI at different investment levels. The bids are evaluated by weighting and combining the scores for all the criteria in a single step. Weights for technical capability and fiscal package increased in importance in later rounds at the expense of the work programme, particularly for deep water blocks, indicating a shift in the government's objective from exploration activity to increasing government revenue.

A summary of the bidding experience over successive NELP rounds is provided in Table 7.1

10. Some of the blocks offered in later rounds may include acreages that were offered and relinquished in earlier rounds.

11. Operational blocks are those in which exploration has begun and haven't been relinquished, but not necessarily declared commercial.

12. Cost recovery factor is the percentage of revenues recoverable by the contractor to cover exploration, production and development costs.

Table 7.1: Summary of bidding across NELP rounds

NELP Round →	NELP I	NELP II	NELP III	NELP IV	NELP V	NELP VI	NELP VII	NELP VIII	NELP IX
Year	1998	2000	2002	2003	2005	2006	2007	2010	2012
Blocks Offered	48	25	27	24	20	55	57	70	34
Blocks Bid for	28	23	24	21	20	52	45	36	33
Bids Received	45	44	52	44	69	165	181	76	74
PSCs Signed	24	23	23	20	20	52	41	32	19
% Blocks Awarded	50%	92%	85%	83%	100%	95%	72%	46%	56%
Area Awarded ('000 sq. km.)	229	263	205	193	114	306	113	53	26
Blocks Relinquished	20	19	18	15	14	38	23	7	2

Source: (DGH, 2015, p. 64; MoPNG, 2014-15, p. 24).

Interest in NELP, as indicated by the number of bids received per block, peaked between 5th and 7th rounds. On an average, about 2 bids were placed per block, which indicates lukewarm participation. Conversion of auctions to contracts peaked in the 5th round when PSCs were signed for 100% of the blocks on offer. However, the conversion ratio declined steadily to 46% in the 8th round and 56% in the 9th round. Overall, of the 360 blocks on offer, over 29% didn't result in contracts. The DGH does not provide information on actual bids received, even anonymised, hence one can only guess the reasons for the low participation and conversion rate in later NELP rounds. It could be that the blocks on offer in NELP rounds VIII and IX were not as attractive. Or it could be due to the controversies surrounding contracts from earlier rounds and the gas pricing and utilisation policies of the government (these are detailed in later sections of this chapter).

7.5.1 Competition

NELP has not succeeded in changing the oligopolistic structure of the Indian E&P sector. At first look, there appears to be diverse participation from many players as shown in Table 7.2.

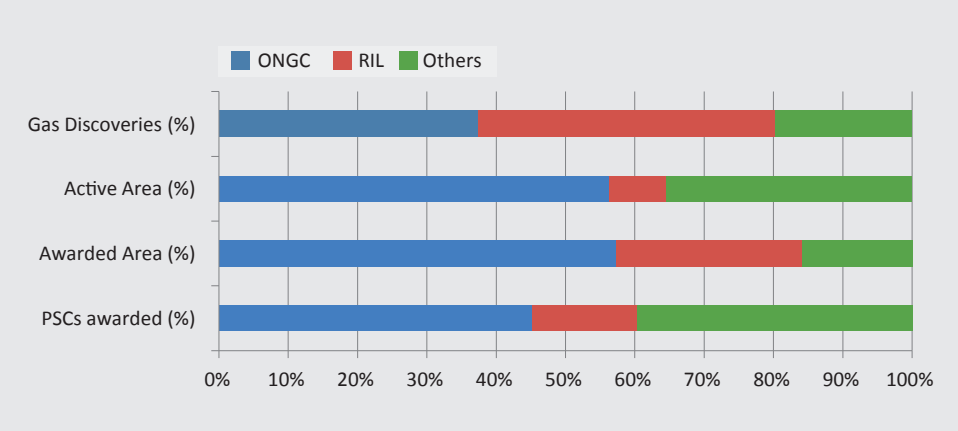
Table 7.2: Participation in NELP by type of company

	Total	PSUs	Pvt. Indian	Foreign
Companies prior to NELP	35	5	15	15
Companies under NELP	117	11	58	48
Operatorship of NELP blocks	254	144	70	40

Source: (DGH, 2016, p. 24).

Notwithstanding the number of companies participating, E&P under NELP is dominated by two players — ONGC and Reliance Industries Limited (RIL) — who operate a majority of the blocks. Of the 144 blocks operated by PSUs, 111 or roughly 77% are with ONGC. Over half of the 70 blocks operated by Indian private companies, viz. 38, are with RIL. Consequently, over 80% of the total area awarded and 80% of the gas discoveries under NELP have been made by just these two operators as shown in Figure 7.2.

Figure 7.2: NELP acreage and discoveries under major operators



Source: Computed based on (DGH, 2016).

7.5.2 Weak international participation

Major international oil companies such as Exxon Mobil, Chevron, ConocoPhillips, and Royal Dutch Shell have not participated in the NELP process. Some of the companies that did participate, such as BHP Billiton and Santos, later withdrew citing regulatory hurdles, specifically defence clearances. (Mahajan, 2012; PTI, 2013) There has been declining interest in the more recent rounds with no international companies being awarded contracts in the last round of NELP.

Reasons cited for the decline in participation are delays in clearances and regulatory approvals (PTI, 2013), contract renegotiation, poor prospectivity, and risk perception. During consultations conducted by the Committee on Allocation of Natural Resources headed by Ashok Chawla, industry representatives felt that India's rating for perception of risk is very low since prospective bidders are concerned about the quality of blocks on offer, asymmetry of seismic data availability, and seismic data quality. In addition, during the third meeting of the same committee, the member-secretary asserted that "all Production Sharing Contracts (PSCs) commitments should be honoured as any post contract re-negotiation decreases investor (especially external) confidence; this may explain the hesitation of big foreign players to participate in NELP" (GoI, 2011, p. 70).

7.5.3 Bid evaluation criteria

For the first three rounds of NELP, the technical capability of the bidder was given a weight of 6%, as opposed to 60% for the work programme and 30% for the fiscal package. In rounds four and five, the weight for technical capability was increased to 9% for deep water blocks — still significantly low compared to the other two criteria. Such a low weight to technical capability is incongruent with the intent of bringing superior technical expertise to increase the pace of exploration. RIL, for instance, was able to win an important (and perhaps most promising) block in the first round of NELP without much prior experience in exploration and production activities. This was rectified in later rounds. In the last four rounds of NELP, the weight given to technical capability was increased up to 30% for bidding of deep water blocks.

7.6 Slow pace of exploration

At an aggregate level, oil and gas reserves have grown at roughly 3% per year since 1999, which is significantly higher than the reserve growth in the preceding decade. Despite the progress, there are a lot of areas of concern with respect to exploration activities.

The Hydrocarbon Vision 2025 formulated by the MoPNG in 2000 called for appraisal of the Indian sedimentary basins to the extent of 25% by 2005, 50% by 2010, 75% by 2015 and 100% by 2025. In comparison to these targets, only 48% of the sedimentary basin in India has been appraised[13] as of March 2014, with on land areas faring worse at 35% (DGH, 2015, p. 16).

13. An area is considered appraised if a minimum amount of seismic exploration is done, at least one exploratory well is drilled, and geological knowledge is developed through data integration with neighbouring areas.

A commonly used indicator for measuring the pace of reserve accretion is the reserve replacement ratio (RRR), which is the amount of reserves added during a year relative to the amount of gas extracted. An RRR of 1 or higher indicates non-declining reserves. Table 7.3 shows gas RRR under PSC over the years.

Table 7.3: Reserve replacement ratio for natural gas under PSC regime

Year	Reserve accretion (BCM)	Production (BCM)	RRR
2007–08	39.73	7.73	5.14
2008–09	-0.71	8.09	-0.09
2009–10	50.56	21.99	2.3
2010–11	39.83	26.77	1.49
2011–12	35.92	21.61	1.66
2012–13	3.24	14.49	0.22
2013–14	35.5	9.5	3.74
2014–15	51.71	8.92	5.8

Source: (DGH, 2016, p. 189).

In isolation, reserve replacement appears to be happening at a healthy pace. However, this is more due to decline in gas production than expedited exploration activity as can be seen above. Issues with declining gas production have been dealt with in greater detail in Section 7.7.

The minimum work programme has not been completed in a number of blocks attracting penalties in the form of liquidated damages. A total of US$ 66 million was paid in penalties up to 31st March 2011. Actual investment made in exploration is said to have been lower than what was committed at the time of bidding. As per the PSC terms, compliance is monitored against the minimum work programme quoted in the winning bid. Hence penalties don't reflect the true extent of under-investment that may have happened.

In absence of data on block-wise investments committed and made, we have relied on the report of the Committee on Allocation of Natural Resources headed by Ashok Chawla. A total of $1,082.5 million exploration investment was committed in NELP I, against which an investment of $2,856 million was made. Even so, there was investment shortfall in 12 blocks. 11 of these blocks have been relinquished, and penalties have been levied for five blocks. This implies that blocks have been relinquished without fulfilling the exploration goals. Table 7.4 shows the number of blocks where there was a shortfall in investments made vis-à-vis commitments in rounds one to five as of 2011 (GoI, 2011, p. 64).

Table 7.4: Investment shortfall up to 2011 in NELP rounds 1–5

	NELP I	NELP II	NELP III	NELP IV	NELP V
Number of blocks awarded	24	23	23	20	20
Number of blocks relinquished	16	18	6	3	3
Number of relinquished blocks with investment shortfall	11	15	0	1	3
Number of relinquished blocks penalised	5	7	0	0	0
Number of non-relinquished blocks with investment shortfall	1	1	8	11	12
Number of non-relinquished blocks penalised	0	0	0	0	1

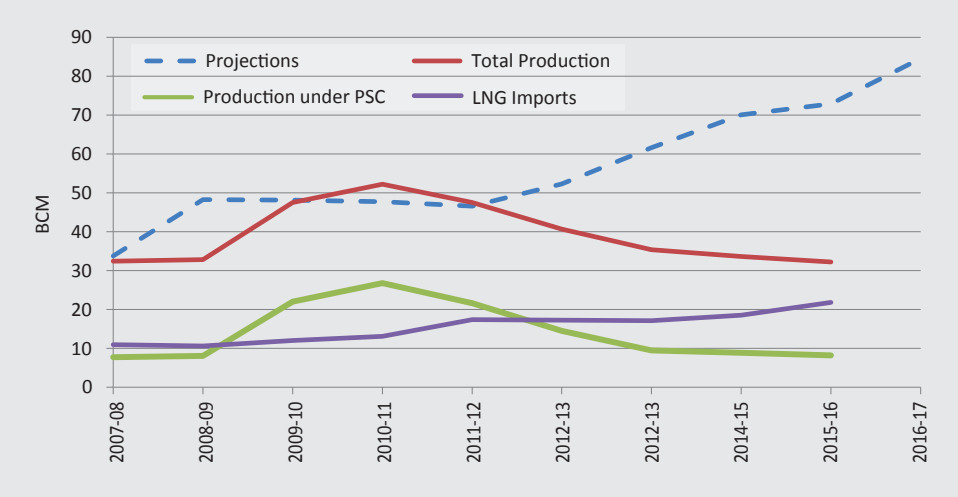
Source: (GoI, 2011, pp. 62, 64).

Some of the delays in exploration were caused due to delays in obtaining licenses and statutory clearances related to land, environment, defence, forests, roads, wildlife, etc. Naturally, such delays are not penalised. According to a study conducted by Petroleum Federation of India in 2005, over 70 approvals are needed for drilling an exploration well. Consequently, operations are delayed by two to three years in some cases, necessitating extensions of the exploration phase (Petrofed, 2005, p. 12). As of December 2014, 116 blocks were affected due to delays in clearances (PTI, 2014; Lok Sabha, 2014). Exploration was prohibited in nine blocks by the Ministry of Defence due to security concerns. While approvals are needed to ensure that social, environmental and national security norms are followed, some of the delays point to a lack of coordination between different government agencies. For example, acreages where exploration is prohibited for defence reasons should not have been auctioned in the first place.

7.7 Decline in gas production

NELP gas production which dramatically increased in 2008–09 following commencement of production from KG-D6 block peaked in 2010–11 and steadily dropped from 2011–12 onwards, reaching 2008–09 levels by 2015–16 as shown in Figure 7.3.

Figure 7.3: Projected vs. actual domestic gas production and LNG imports



Source: (MoPNG, 2014, pp. 3, 7, 25; MoPNG, 2012; MoPNG, 2007, p. 82; MoPNG, 2016, pp. 4, 8, 29).

Figure 7.3 shows the overall domestic oil and gas production in the country during the 11th and 12th five year plan periods. Of the 32.2 BCM of gas produced in 2015–16, only about 4 BCM is from NELP blocks.[14] The production trend is in sharp contrast to projections by the 11th and 12th five year plan working groups, shown with a dotted line in the figure.[15] There has been a steady increase in LNG imports coinciding with a drop in NELP production.

Reduced gas production from the KG-D6 block and non-conversion of discoveries from other blocks to production are the main reasons behind this gap. We explore these reasons in the next couple of sections.

7.7.1 Slow pace of development

Conversion of discoveries to development and production has been underwhelming. According to data available on the DGH website[16], of the 110

14. Although about 8.2 BCM of natural gas is produced from PSC blocks, more than half of this production is from pre-NELP blocks (MoPNG, 2016, p. 40)

15. The 12th plan projections were subsequently revised downward in an MoPNG notification issued in May 2012, primarily due to expected fall in gas production from NELP blocks. However, the actual production was lower than even these revised projections.

16. Data taken from dghindia.org/index.php/static_page?pageId=Discoviries, retrieved on 21st October 2015. DGH doesn't specify when this data was last updated, but it is certainly dated. Some of the blocks listed to be in the FDP stage have been relinquished and the number of wells under development are 22 by the end of 2014 (MoPNG, 2015, p. 18). Still, the data is used here to illustrate the slow pace in converting discoveries to appraisal and development.

PSCs awarded up to NELP V in 2003, there have been 113 discoveries in 28 blocks. 50 of these discoveries are in deep water areas spanning 12 blocks, 30 in shallow water areas and 33 on land. However, as shown in Table 7.5, gas production has commenced from only five blocks, of which one is a deep water block, one is a shallow offshore block, and three are on land. The effective start year of contracts from these rounds was 2005 or earlier, so production could have commenced by 2015 for commercially viable discoveries, particularly those discovered earlier in the exploration stage.

Table 7.5: Timeline of discovery and gas production in producing NELP blocks

Block	NELP Round	Year of Signing	Year of 1st Discovery	1st Year of Production
CB-ONN-2000/2[17]	II	2001	2004	2004-05
CB-ONN-2000/1	II	2001	2002	2007-08
KG-DWN-98/3	I	2000	2002	2008-09
CB-ONN-2003/2	V	2005	2008	2013-14
KG-OSN-2001/3	III	2002	2005	2015-16

Source: DGH website.

For example, the Gujarat State Petroleum Corporation (GSPC) which operates the KG-OSN-2001/3 block discovered gas in 2005, submitted the FDP in 2009 and was to begin production in 2012 (EBR, 2009). However, production from this block began only in 2015–16. ONGC, on the other hand, announced its first discovery in the neighbouring KG-D5 (or KG-DWG-98/2) block in 2006. However, the FDP for this block was approved by the ONGC board only in March 2016 and production is expected to begin in 2020 (ONGC, 2016).

Some delays in appraisal and development are due to the time taken in obtaining clearances from various ministries, and some others are reported to be due to delays in operational decision making. In other cases, difficult geological conditions have been blamed for the delays. Data that can help understand the specific reasons for the delays in each of the blocks is not publicly available. Block-wise data reported on the DGH website does not contain details such as commercial viability of discoveries, stipulated timelines vis-à-vis achievements, reasons for any deviations, and other useful information that can help understand the reasons behind non-performance.

17. CB-ONN-2000/2 was closed in 2013–14 after completion of field life.

ONGC's case is particularly strange. The company has not commenced production from any of the 115 blocks it was awarded under NELP, 7 out of which appear to have been declared as commercially viable as per the DGH website. And this is a company that produced over 65% of the natural gas produced in the country in 2014–15 (MoPNG, 2015, p. 25). Justice A. P. Shah who was looking into a dispute between RIL and ONGC regarding joint reservoirs (see Section 7.9.3), made the following observation:

> "The long periods of alleged inactivity on the part of ONGC in this case particularly must be examined further. For example, ONGC had some rights to explore in the Godavari PML block in the KG basin since at least 1997, and complete control over its blocks in the area since 2003. However, even today, ONGC has hardly progressed beyond exploratory stage, and there is no commercial production in either of its blocks under consideration. An entity of its stature and relevance cannot be permitted to languish for a period of 15 to 20 years in a zone of opportunity. The Committee believes that the MOPNG should make efforts to understand what steps may be taken to avoid a situation like this in the future." (Shah, 2016, p. 103)

7.7.2 Non-adherence to development plan

Gas production from the KG-D6 block began in April 2009, and according to the approved field development plan (FDP), production from the Dhirubhai-1 and 3 fields within the block was expected to peak at 80 mmscmd by 2012-13, which would effectively double the domestic gas supply (Ministry of Finance, 2010–11, p. 267). Several plans were laid out to utilise this gas by allocating it to the various consuming sectors. However, in August 2012, RIL filed a revised FDP, cutting gas reserves in the block from 292 BCM (10.3 Tcf) approved in 2006 to 88 BCM (3.1 Tcf), a drop of 70%. Production from KG-D6 block has steadily dropped over the years to 4.463 BCM in 2014–15, corresponding to about 12 mmscmd (RIL, 2014-15, pp. 48, 65). The reasons provided by RIL were drop in pressure in the wells and increased water ingress leading to shutdown of wells and lower output of gas per well.

However, the CAG found in its audit that RIL had drilled fewer wells than were listed in the Addendum to the Initial Development Plan (AIDP). The DGH engaged a reservoir consultant, P. Gopalakrishnan, to analyse the performance of individual wells/pools along with the production rate of D1 and D3 fields, who concluded that the shortfall of gas production is due to non-drilling of the adequate number of wells as per the AIDP, and suggested changes to well completion policy among other things. (Mehdudia, 2013)

Meanwhile, the GoI imposed penalties for not meeting production targets in the years 2010–11, 2011–12 and 2012–13. In response, RIL initiated international arbitration proceedings against these penalties, claiming that the contract does not talk about levy of penalty for producing less than output estimates. Arbitration proceedings are underway as of October 2016. (Pathak, 2016)

7.7.3 Stranded capacity

Significant investments made in gas-based power plants and fertilizer plants have been stranded due to a lack of affordable gas supply. Gas shortages resulted in a generation loss of 73.09 Billion Units (BU) in 2012–13 and 51.78 BU in 2013–14 (CEA, 2015). Many of these projects, particularly in the state of Andhra Pradesh, came up based on anticipated availability of affordable gas from the Krishna-Godavari (KG) basin, specifically the KG-D6 block (GoAP, 2003, p. 32).

Table 7.6 shows gas-based power capacity addition over the years and the shortfall in gas supplied to power plants. Much of this capacity is in the form of combined cycle units built for base load generation, hence normative availability of 80% is assumed. As can be seen, more than 10 GW of gas-based power plants were added after 2002 when a significant gas discovery was made in the KG-D6 block, and these have been operating well below their normative availability.

Table 7.6: Gas-based power capacity additions and gas shortfall

Year	Capacity at the end of the year (MW)	Year wise capacity addition (MW)	Gas required at 80% PLF (mmscmd)	Average gas supplied (mmscmd)	Shortfall (mmscmd)
2002–03	9949	---	42.90	25.12	17.78
2003–04	10155	206	43.78	25.62	18.16
2004–05	10225	70	44.20	30.7	13.50
2005–06	10920	695	47.45	35.37	12.08
2006–07	12444	1525	54.38	35.1	19.28
2007–08	13409	965	58.37	38.14	20.23
2008–09	13600	191	59.21	37.45	21.76
2009–10	15769	2170	69.41	55.46	13.95
2010–11	16640	871	72.37	59.31	13.06
2011–12	18381	1741	76.51	56.28	20.23
2012–13	20110	1729	80.62	40	40.62

Source: (CAG, 2015, p. 77).

In May 2015, the GoI introduced a plan for gas-based power projects that supply power to distribution companies and are stranded or getting low quantities of gas from domestic fields. Under this plan, a subsidy would be disbursed based on bids for the least subsidy requirement. Thus, in effect, public funds are being used to make predominantly private projects viable because of non-adherence to approved production plans.

7.8 Issues with NELP incentive structure

In earlier NELP rounds, a stair step based formula was used where the bidder would quote the GoI's share of the profits for different ranges of the investment multiple (explained in Section 7.3). From NELP VII onwards, a linear sliding scale was used where the bidder quotes the GoI's share for IM less than or equal to 1.5 and greater than or equal to 3.5, with the shares for IM in between being determined on a linear scale.

The example provided in Table 7.7 shows the IM formula from the winning bid for the KG-D6 block that was auctioned in the first round of NELP. In this example, the GoI's share of profit petroleum could vary from as low as 10% to as high as 85%.

Table 7.7: An example profit sharing formula (NELP rounds I-VI)

Investment Multiple	GoI's share	Contractor's share
IM ≤ 1.5	10%	90%
1.5 < IM ≤ 2	16%	84%
2 < IM ≤ 2.5	28%	72%
2.5 < IM ≤ 3	85%	15%
IM > 3	85%	15%

As of 31st March 2015, the cumulative GoI take across all NELP rounds was ₹ 71,316 crores in profit oil and gas and ₹ 40,829 crores in royalty. (DGH, 2016, p. 138)

The incentive structure under NELP has been an area of hot debate. The CAG noted in its audit that, due to the structure of IM-based profit sharing formula for the KG-D6 block up to NELP VI (See Table 7.7) where there can be a steep jump in the GoI's profit share when IM crosses 2.5, the contractor has a strong incentive to strategically plan investments so that the IM stays below 2.5 (CAG, 2011, p. 150; GoI, 2011, p. 48). An increase in capital expenditure could result in an increase in the contractor's share of profit petroleum, despite a reduction in the total profit petroleum as well as the GoI's share of profit petroleum. Front-loading

the investments would result in reduction in the GoI's share on a discounted cash flow basis. In response to these concerns, a linear sliding scale was introduced in the profit sharing formula for PSC contracts from NELP-VII onwards, drastically reducing gaming possibilities.

7.9 Governance deficit

Several governance issues have been raised primarily with respect to non-compliance with PSC terms, approval of investments, relinquishment of exploration areas, information asymmetry, underproduction, and drawal of oil and gas from neighbouring blocks. In addition to these issues, there has been criticism regarding unfair business practices in natural gas operations, as indicated in several news articles spanning the last 15 years (Kaushik, 2014; Asthana, 2014; Thakurta P. G., 2014; The Economist, 2014a; Ramesh, 2016). While it is difficult to prove motive, suffice it to say, many of these issues are a result of weak institutional mechanisms that preclude meaningful regulation and oversight of upstream oil and gas operations.

7.9.1 Non-compliance with PSC terms

In November 2007, the GoI requested the Comptroller and Auditor General of India (CAG) to conduct a special audit of PSCs under provisions of Article 25 of the PSC in light of large stakes of the GoI in the form of royalty and profit share and concerns raised regarding expenditures incurred by the contractors. The main purpose of the audit was to study the processes in place at the DGH and MoPNG to monitor and ensure compliance with PSC terms and to ensure that effective mechanisms were in place to ensure that the GoI revenue interests were properly protected. KG-D6 was the only deep water block studied under this audit and the only NELP block for which supplementary scrutiny of records was conducted. As part of this audit, the CAG found several violations of the provisions in the PSC. These include not relinquishing area when transitioning between exploration phases, not notifying discovery, and not submitting test reports in a timely manner. (CAG, 2011, p. 34)

The CAG found that RIL was allowed to claim the entire KG-D6 contract area as discovery area and transition to subsequent exploration phases without relinquishing 25% of the total contract area at the end of each phase as stipulated in the contract terms. The MoPNG issued a relinquishment order in October 2013 for 81% of the area of the block citing expiration of the production deadline for those

fields. However, RIL challenged this order through arbitration, stating that the MC had agreed to a phased development approach. (Business Standard, 2015)

The CAG also found that some of the activities undertaken by RIL under the AIDP were carried out prior to submitting the plan for review and approval which increases the risk of such approvals becoming fait accompli.

There have been issues of non-fulfilment of the committed work programme. In 2004–05, an ONGC representative said in response to a question from the Committee on Public Undertakings of the 14th Lok Sabha as to whether NELP provisions are satisfactory:

> "We have represented to the Government that if blocks are awarded on MWP, and if MWP is not complied with, then the sanctity of award process itself is questioned. And then if we say that MWP is adjusted from this block to that, this goes against the basic principle of tendering or bidding. That is one thing which we have submitted to the Government. It is unfair. If we have bid three wells and somebody else have bid four wells, by all means four is more than three and they should get the award. I have nothing to complain about. But having bid for four wells, not even one well is done and extensions are being given." [sic] (Lok Sabha, 2004–05, p. 50)

The DGH recommended penalties against ONGC and RIL for defaulting on contract terms such as non-fulfilment of the committed work programme (PTI, 2006). It is not clear if the penalties have actually been levied by the MoPNG.

7.9.2 Approval of investments

Under the NELP regime, profit is shared between the contractor and the government. Thus, costs incurred during the exploration, development and production stages have a bearing on the government's share of the profits. Due to the profit sharing formula under NELP, particularly up to the sixth round, timing of the capital investments also has an impact on the GoI's share (see Section 7.8). This brings in additional regulatory burden since costs incurred by the contractor need to be monitored to ensure that they are prudent and that the government's share of the profits is protected while also maximising exploration and production.

There have been concerns that due diligence was not applied by the DGH when approving investments. RIL reported a steep escalation in capital expenditure for developing the KG-D6 block – from $2.4 billion according to the Initial Development Plan (IDP) submitted in 2004 to $8.8 billion as per the Addendum

to IDP (AIDP) submitted in 2006 (Jishnu, 2009; PTI, 2012). This additional capex was expected to increase gas reserves from about 150 BCM to 320 BCM[18], thus increasing production from 40 mmscmd to 80 mmscmd. It is alleged that the DGH approved these investments without proper scrutiny, and an entity that the DGH claimed to have vetted the costs is alleged to have close ties with RIL (Jishnu, 2009). In response, the DGH issued a note explaining why the investments made by RIL in the KG-D6 block are justified (DGH, 2009)[19]. The DGH also claimed that these costs were audited by the Comptroller and Auditor General of India (CAG), although the CAG reportedly did not have access to RIL's books at that time (PTI, 2009).

The CAG conducted audits of hydrocarbon PSCs (NELP as well as pre-NELP) in 2011 and 2014 as part of which accounts of the KG-D6 block were examined. The CAG pointed out several issues in the tendering process followed for sub-contracts and purchase of equipment for the KG-D6 block which resulted in cost escalations (CAG, 2011, p. 82; CAG, 2014, p. 48). These costs had been approved by the MC raising the possibility of information asymmetry or wilful collusion within the MC and/or lack of capacity or motivation of the DGH to critically review the contractor's submissions.

RIL claims that its production costs for D1/D3 fields within KG-D6 block, at $5.2 billion to develop 320 BCM (or 11.3 Tcf), are among the lowest in the world and that costs in GSPC and ONGC blocks are much higher at $2 billion to develop 40 BCM (1.4 Tcf) in the KG-OSN-2001/3 block and $7.7 billion to develop 54 BCM (1.9 Tcf) of gas in the neighbouring KG-D5 block. (PTI, 2011) Geological conditions differ from block to block and costs may vary significantly. Hence, the regulator needs to be diligent in determining cost prudence and to do so in a transparent manner. The DGH has done neither, perhaps due to lack of capacity or due to its unwillingness to function in an open manner.

Meanwhile, due to lower than anticipated production from the block — production in 2014–15 was about 12 mmscmd instead of 80 mmscmd as per the approved FDP — the GoI disallowed $1 billion worth of costs when calculating profit petroleum. RIL initiated arbitration proceedings in November 2013 arguing that the contract does not have any provision for disallowing costs on account of not meeting expected production levels (PTI, 2014a).

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18. The convention is to refer to quantity of reserves in trillion cubic feet (Tcf). The increased capex was expected to increase reserves from 5.32 Tcf to 11.3 Tcf. These units have been converted to billion cubic meters (BCM).

19. This note was available at www.dghindia.org/pdf1/D6.pdf as of May 2016, but has since been removed.

The above disputes illustrate the administrative challenges in administering a profit sharing contract, which involves ascertaining prudence of costs incurred by the contractors. The Committee on the 'Production Sharing Contract Mechanism in Petroleum Industry' headed by retired RBI governor C. Rangarajan, recommended a revenue sharing model wherein the government would receive a share of the revenue from sale of gas irrespective of the costs incurred by the contractor (GoI, 2012).

However, the Committee on the 'Roadmap for Reduction in Import Dependency in the Hydrocarbon Sector by 2030' headed by Vijay Kelkar observed that profit sharing contracts provide better incentives to increase domestic production, and suggested some administrative reforms to enable smoother implementation. These reforms include increasing the DGH's technical capacity and limiting its role to technical aspects of the operations such as ensuring that good reservoir management practices are followed by the contractor. Fiscal oversight would lie with the revenue departments within the GoI who would be responsible for cost assessment and ensuring that the GoI receives its due share of the profit petroleum.

7.9.3 Issues with connected reservoirs

A couple of blocks operated by ONGC in the KG basin, namely KG-D5 and G-4, are adjacent to the KG-D6 block operated by RIL. In May 2014, about 5 years after RIL began production in KG-D6, ONGC filed a petition with the Delhi High Court alleging that RIL knowingly extracted around 15% of the gas, or 12–18 BCM, from ONGC's blocks.

Article 12 of the PSC requires the contractors to prepare a joint development agreement in the case of joint reservoirs, which is then reviewed by the GoI. However, the PSC does not specifically deal with disputes that arise after production commences on one side, as in this case. Hence, RIL initially claimed that no retrospective penalties can be levied, and joint development is not possible since the wells only have 3–4 years useful life left in them.

A third party consultant was appointed to establish continuity of reservoirs across blocks operated by ONGC and RIL (PTI, 2015). The consultant concluded that KG-D6 shares a common reservoir with G-4 and KG-D5 blocks, and that 11.122 BCM of the gas drawn by RIL from KG-D6 was from the neighbouring blocks.

Subsequently, the MoPNG constituted a single member committee on the 'Dispute Regarding Oil and Gas Blocks in KG Basin' comprised of Justice A. P. Shah, to

recommend the future course of action on the basis of the consultant's report. The Shah committee concluded that RIL had prior knowledge about the connectivity and continuity of reservoirs and that the GoI, being the custodian of the country's natural resources on behalf of the people of India, is entitled to receive the profit gained by RIL for the excess gas drawn from neighbouring blocks. The committee noted that ONGC too had prior knowledge of possible continuity and did not act for six years, and has no claim on the compensation as it did not start any drilling activity in the neighbouring blocks. The committee also recommended that the DGH/GoI quantify the extent of unfair enrichment by RIL, since this involves looking at costs incurred by RIL for developing wells and extracting gas (Shah, 2016).

While improving terms of the PSC and the manner in which blocks are demarcated can help avoid such disputes, this episode highlights ONGC's own tardiness in developing the G-4 block where gas was discovered over 12 years ago. ONGC's operations appear to be sluggish in the neighbouring KG-D5 block as well, where the first discovery happened in 2001, but production is yet to commence.[20] It has been suggested that ONGC got its act together only when there was a change in senior management (Mukul, 2015). It is perhaps a reflection of the state of affairs that something such as this was not caught by the DGH during the KG-D6 management committee review given that the wells in question were drilled close to the border.

7.9.4 Regulatory capacity

The GoI has oversight over E&P operations both directly and through the DGH's representation in the management committee (MC) for each block. The MC plays a limited role in the procurement process, largely restricted to prior intimation of the list of pre-qualified bidders. The CAG in its audit found that the GoI's representatives in the MC did not pay adequate attention to various proposals and decisions and how they would impact the GoI's share of profit petroleum. In addition, there are concerns about differing principles being adopted in different MCs (GoI, 2011, p. 52). On the one hand, the DGH lacks the capacity to monitor hundreds of PSCs simultaneously. On the other hand, the contractor's representatives in the MC would be fully aware of the impact of these decisions on the contractor's share. This asymmetry in capacity and information has led to serious doubts on whether the regulator is equipped to prevent foul play in issues related to cost recovery and profit sharing.

For example, the Shah committee set up by the GoI to recommend further course

20. According to the DGH website, gas was discovered in KG-D5 block in July 2001 in a well named DWN-R-1 (Annapurna). However, the status indicates that the FDP is yet to be submitted by the operator.

of action on the dispute regarding gas extracted in the KG-D6 block from a joint reservoir (See Section 7.9.3) noted that an appraisal report that was filed with the Canadian regulator in 2003 was not shared with the MC of the KG-D6 block. This appraisal report contained crucial information on the aspect of joint reservoir with neighbouring blocks (Shah, 2016, p. 102).

Serious questions have been raised regarding the technical and financial contribution of at least one international player, namely Geo Global Resources Inc., Canada (GGR). GGR is a 10% partner, with GSPC as the operator, in the consortium that successfully bid for the KG-OSN-2001/3 block in the 3rd round of NELP. However, it was found in a CAG audit that GGR was admitted into the consortium as a technical expert without contributing its financial share, leaving GSPC to fund GGR's share of the exploration cost. More alarmingly, due to adoption of a deficient geological model prepared by GGR, the consortium incurred around 12.75 times the estimated drilling cost during the exploration stage (CAG, 2012, p. 31). It is not clear if issues such as this were caught in routine reviews that happen at the MC, DGH and MoPNG.

The DGH's dual role as regulator as well as technical advisor to the government is a cause for concern, as it means that there is no arms-length distance from the government, a pre-requisite for effective independent regulation. In addition, the DGH is manned by staff drawn on deputation primarily from NOCs like ONGC and OIL — organisations that DGH itself is responsible for regulating. This is incompatible with the lofty goal of providing a level playing field to all prospective players. Even if no favours were granted to NOCs, such an arrangement could give the impression of conflict of interest, thus leading to distrust of the regulator.

Several committees set up to study various aspects of the upstream hydrocarbon sector have strongly recommended reforms at the DGH. The Committee on 'Allocation of Natural Resources' headed by Ashok Chawla (GoI, 2011) and the Committee on the 'Roadmap for Reduction in Import Dependency in the Hydrocarbon Sector by 2030' headed by Vijay Kelkar (GoI, 2014) have suggested institutional reforms involving higher independence and strengthening of technical capabilities of the DGH. The Kelkar committee suggested that DGH's role be limited to technical regulation, but with sufficient financial autonomy and resources for capacity building (GoI, 2014, pp. 22,23).

The Shah committee made the following observation when reviewing the dispute surrounding connected reservoirs:

> "DGH, despite being the regulatory authority in the sector, was helpless and entirely reliant on the operators not only for raw data, but also for the interpretation of the data so provided. This is not a desirable situation from any perspective for a regulator in an area involving such complex technicalities. To address this issue, the DGH must look to become more proactive in exercising its regulatory authority, whether it is in the form of better vigilance, acquiring more incisive technical skills, or stronger enforcement powers. The DGH must, in particular, ensure that it has the adequate technical expertise and infrastructural wherewithal to conduct regulatory operations in [sic] unhindered fashion. The presence of a strong, empowered, vigilant and diligent regulator cannot be emphasised enough, particularly in a sensitive and vital sector like petroleum."

7.9.5 Lack of transparency

There have been serious concerns about the transparency of the NELP process worth billions of dollars. Crucial information is not available in the public domain on important aspects such as investment levels in blocks, data related to hydrocarbon discoveries and regulatory lapses, and justification for pricing and utilisation policies. Model PSC and block-wise work done is available on the MoPNG's RTI website for NELP-V onwards, however, this information is not available for rounds I-IV.[21] Data on winning bids is not available whereas signed contracts should have been put up by the DGH or the MoPNG as a matter of good practice.

Neither the DGH nor the MoPNG publish block level data such as number of competing bids, winning bid, final PSC, partial relinquishments if any, E&P progress vis-à-vis stipulated timelines, verified and validated reserves, approved investments, and expected and actual production profiles. Therefore, media reports become the primary sources of information, in spite of a DGH-issued guideline that states that discoveries should be reported in the media only after the DGH certifies them, in order to avoid false information affecting the market sentiment.[22] Though the DGH has occasionally acted on such media reports and censured the contractor (DGH, 2009), it would be far better if it regularly (say quarterly) published this data in a simple, easy to access format. This data is certainly important from public interest, policy analysis and investment analysis points of view, as it concerns reserves of a public resource and investments into extracting that resource, and has interlinkages

21. petroleum.nic.in/rtimopng1.htm

22. 'Guidelines for Announcement of New Discoveries under the Production Sharing Regime' were published by the DGH in May 2006, however, they are unavailable at the DGH website now. A news article referring to this issue is: articles.economictimes.indiatimes.com/2006-06-02/news/27439886_1_dgh-discoveries-new-gas.

with other crucial sectors. Publishing such data in a timely manner will help improve transparency, governance and investor as well as public confidence in contract implementation. This is particularly important in the oil and gas sector where every dispute is seen as a scam in the making.

The Chawla committee recommended that the DGH engage in greater public disclosure of issues relating to investment audit and exploration commitment and of approvals granted by the DGH along with reasons thereof (GoI, 2011, p. 60). The disclosure levels of the Norwegian Petroleum Directorate offer a good example.[23]

7.10 Open Acreage Licensing Policy (OALP)

One licensing mechanism that has been repeatedly recommended for increasing E&P participation since the launch of NELP is the Open Acreage Licensing Policy (OALP) for oil and gas blocks (GoI, 2012; GoI, 2014, p. 9; GoI, 2011, p. 50). OALP gives contractors flexibility in identifying acreages of interest rather than waiting for an 'NELP round'. Once an expression of interest is received, the block is auctioned through the same tendering process as NELP. OALP is dependent on creation of a National Data Repository (NDR) which has been long overdue and was finally set up in mid-2016.[24] Way back in 2002, the Parliamentary Standing Committee on Petroleum and Chemicals for the 13th Lok Sabha said:

> "The Committee are amazed to note that although DGH was created in 1993 as a custodian of all Upstream Petroleum data, the Ministry/DGH have not been able to finalise and implement the National E&P Data-base and Archive during the last 9 years. This was supposed to be done on a priority basis. This shows the casual approach of the Government towards such an important issue of national priority." (GoI, 2011, p. 54)

It is telling that it took over 20 years after the creation of the DGH to create such a repository.

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23. It is worth noting that, according to the Committee on Public Undertakings of the 14th Lok Sabha: "The DGH obtained an outright grant (outside the normal aid programme of Norwegian Govt.) and entered into an Institutional Co-operation Programme with the Norwegian Petroleum Directorate (NPD) for exchange of expertise in the field of petroleum exploration and production needed by a regulatory body. This project was established through a bilateral agreement, between DGH and NPD." (Committee on Public Undertakings — 14th Lok Sabha, 2004, p. 29)

24. The NDR is created by compiling and linking data on blocks for which information was submitted to the GoI by contractual obligation by NOCs and private firms and which are made available to all prospective bidders. By having a common database that is comprehensive and that everyone refers to, concerns of asymmetry in data availability can be addressed. India's NDR for hydrocarbons is online at www.ndrdgh.gov.in/NDR/.

7.11 Gas pricing controversies

Contractors are free to sell NELP gas in the domestic market at a price determined in an arms-length manner, i.e., between unrelated sellers and buyers that don't have a prior contractual or other relationship that could potentially distort from market-determined pricing. Such a sale also needs to be consistent with the GoI's usage policy. If arms-length pricing is not possible, the gas should be sold according to a GoI approved pricing formula. Due to shortfall in production, parallel pricing regimes and disputes, the GoI has been playing a greater-than-anticipated role in pricing and allocation of gas, particularly after a judgement where the Supreme Court ruled that the ownership of natural resources lies with the people of India, on behalf of whom the Union Government shall allocate and use these resources in a manner that is consistent with the common good (Supreme Court, 2010). It is felt that this increased role of the GoI may also be a reason why NELP auctions have not attracted a lot of interest in later rounds.

In 2003–04, RIL placed the winning bid at an international auction by the state-owned power generation company, NTPC Limited (NTPC), for supply of 12 mmscmd of gas at a price of $2.34/mmbtu from the KG basin to NTPC's expansion projects in Kawas and Gandhar. NTPC subsequently issued a Letter of Intent (LoI). However, RIL did not sign the Gas Sale and Purchase Agreement (GSPA) with NTPC citing a clause relating to unlimited liability, resulting in NTPC filing a lawsuit in 2005. The court has not yet ruled on the matter.

Meanwhile, since the NTPC price of $2.34/mmbtu was discovered through competitive bidding, in 2005, RIL agreed to supply 28 mmscmd of gas from the KG basin field to the Dadri power plant of its then sister concern — Reliance Natural Resources Limited (RNRL) — at the same price for 17 years. Subsequently, the RIL conglomerate split into two parts in 2005, with RIL and RNRL falling in different parts of the split, and a family MoU was signed to continue with the gas supply agreement at the decided price. Subsequently, when RIL did not supply the gas as per the MoU, RNRL went to court. The Bombay High Court directed RIL to supply gas to RNRL at $2.34/mmbtu or to work out a new supply contract with RNRL. RIL appealed to the Supreme Court, which asserted that natural resources belong to the people of the country, and ruled that only the GoI has the right to fix the price in a Production Sharing Contract (PSC) when an arms-length price is impossible to find. (Supreme Court, 2010)

In November 2007, the Empowered Group of Ministers (EGoM) fixed the price of KG-D6 gas at $4.2/mmbtu for the first five years of production, i.e., until March 2014, based on RIL's own price discovery mechanism. It should be noted that RIL's mechanism, which involved seeking quotes from gas user companies who had stranded assets based on a formula with limited flexibility, is itself neither transparent nor open and is a non-standard approach that is not followed anywhere in the world (Sreenivas, Sant, & Singh, 2007). If anything, the price RIL quoted in NTPC's auction should have been the basis for the EGoM's decision. Not satisfied with this, RIL sought an import parity price for gas from KG-D6, which was estimated at around $13/mmbtu — thrice the EGoM fixed price, or over 5.5 times the price discovered in the NTPC auction, stating that a price of $4.2/mmbtu was unviable for production from the KG basin (Pathak, 2012)!

The Committee on the 'Production Sharing Contract Mechanism in Petroleum Industry' headed by C. Rangarajan, which was tasked to suggest guidelines for pricing domestically produced gas, proposed a formula in December 2012 based on global trade transactions of gas, which would double the price to $8.4/mmbtu[25] (GoI, 2012). This methodology tries to construct an international market price in the absence of a fully fungible gas market with gas-on-gas competition, and in the process discovers prices that are far removed from actual well head prices realised by producers (Sethi S. P., 2013; Sethi S. P., 2014). Yet, in January 2014, new pricing norms were notified as per the Rangarajan Committee recommendations for most natural gas produced domestically after March 2014, including ONGC and OIL production from nomination fields. However, this price hike was deferred in response to a directive by the Election Commission in the context of the impending general elections in 2014 (Nambiar & Bhaskar, 2014).

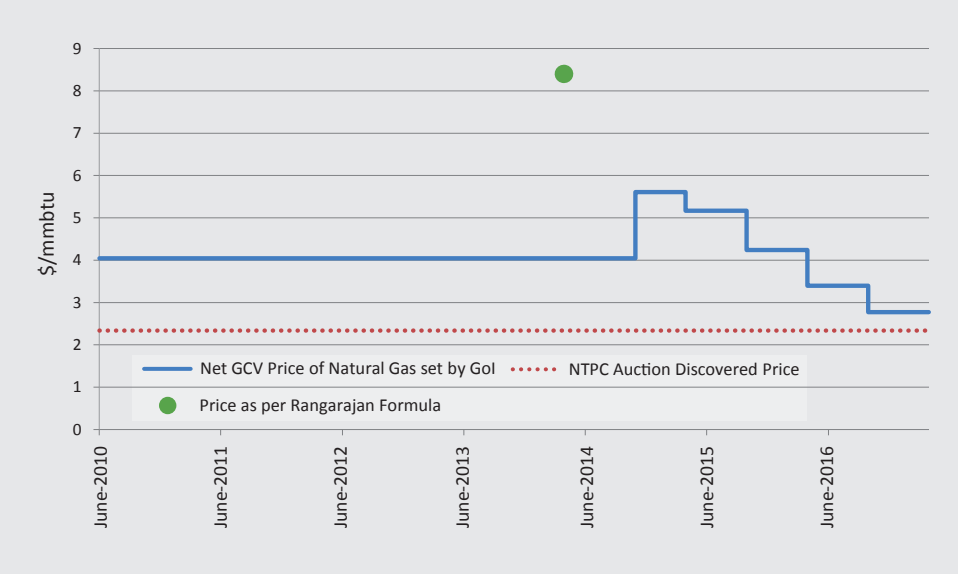
Subsequently, the New Domestic Natural Gas Pricing Guidelines were notified in October 2014 by the newly elected central government, which attempted to fix some of the issues raised with the Rangarajan formula.[26] Net back prices of Indian and Japanese imports, which are significantly higher than well head prices, were eliminated. Canadian Alberta Hub prices, which are 20% cheaper, are used in place of US Henry Hub. Hub-based prices are adjusted downwards to account for

25. This price is arrived at by averaging (a) volume-weighted hub prices in the US and Europe and net back prices of Japanese imports and (b) volume-weighted net back prices of Indian imports at the wellhead of the exporting countries. The logic behind this formula appears to be that it reflects prices that global gas players are getting for their investments on the supply side and prices that Indian consumers are willing to pay for gas beyond current domestic production on the demand side.

26. The methodology is available at petroleum.nic.in/docs/NewNaturalGasPricingGuidelines.pdf.

gas transportation and treatment charges. Finally, the well head price of natural gas consumed in Russia is added to the formula. Price under the new guidelines is periodically determined every six months on a gross calorific value basis (as opposed to the net calorific value basis that was used earlier) and was initially set at $5.05/mmbtu for the period November 2014–March 2015, and has since dropped to $2.50/mmbtu for October 2016–March 2017 due to fall in international gas prices (See Figure 7.4 for Net GCV prices). The concern still remains that gas is priced based on a non-existent international market instead of domestic considerations (Sethi S. P., 2014a).

Figure 7.4: Net GCV price of natural gas under NELP regime



Source: PPAC and various news reports.

Subsequently, RIL initiated arbitration proceedings demanding that the gas pricing formula devised by the previous regime be reinstated. As part of reforms to the E&P fiscal regime in March 2016, the government allowed marketing and pricing freedom for new discoveries in deep water blocks. This freedom would only be available for those blocks that are not under arbitration (The Hindu, 2016). Following this, RIL and its partner British Petroleum (BP) withdrew the arbitration notice (Ray, 2016).

The link between gas pricing and lower production cannot be ignored. RIL has proclaimed on several occasions that prevailing gas prices are unremunerative,

claiming that it is uneconomical to produce gas at existing prices (Pathak, 2012). It was reported recently that Niko Resources which has 10% interest in the consortium that won KG-D6 block considered exiting the KG-D6 block citing uncertainty in long-term price outlook (First Post, 2015). This may not mean too much since British Petroleum took up a 30% interest in the block under the same realities. It is alleged that the real reason behind the drop in production from KG-D6 block is that the contractor has been biding time hoping that the government would revise the price at which gas can be sold in the domestic market. However, RIL categorically denies this, contending that it doesn't make commercial sense to delay production (The Economist, 2014). With so many by-lines to the KG-D6 story, the real reason for decline in production from that block is anybody's guess. It is unfortunate that the block that was supposed to be the poster boy for attracting more investments has instead become an archetype for everything that could go wrong in India's E&P sector.

7.12 Gas utilisation and allocation

Natural gas discovered and produced under the NELP PSC is mandated to be sold in the Indian market as long as India is not self-sufficient in natural gas. In addition, such sale should be made as per the GoI policy for utilisation of gas among different sectors.

It is important to have a long-term strategy on the optimal use of natural gas given its importance in India's ability to meet its developmental, resource and environmental challenges. Unfortunately, while much of the public discourse on gas utilisation is centred around who gets how much gas and at what price, the question of how to use gas to maximise public interest has received very little attention. In the absence of well-functioning markets to perform the allocation function, there is neither a long-term gas utilisation policy nor articulation of the objectives of such a policy.[27] With lack of diversity in domestic gas supply options and falling production, domestic gas-on-gas competition is unlikely at any time in the near future. As long as there is domestic scarcity and no price differentiation, the GoI will play a role in allocation of gas.

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27. The Empowered Group of Ministers (EGoM) constituted in 2007 laid out a set of principles to guide allocation of natural gas. However, the result of this is essentially a priority list of consuming sectors arrived at in a non-transparent and non-participative manner. Moreover, the actual allocation of gas seems to be done in an ad hoc manner, changing based on the crisis of the day (PTI, 2009b; Modi & Mukul, 2009). A consolidated list of gas allocation policies is available at petroleum.nic.in/docs/gp/consolidated%20gas%20allocation%20policies.pdf.

The GoI needs to develop a comprehensive policy factoring in Indian realities, while working towards developing an effective and competitive gas market. One of the pre-requisites for developing a gas market is the development of a national gas grid. A half-hearted attempt was made to introduce regulation to assist buildout of cross-country pipeline networks and regional distribution networks. See Box 7.1 for more details.

Box 7.1: Regulation of downstream gas networks

Development of robust gas infrastructure and predictability in long term availability and price of gas are essential for a vibrant national gas market. Gas infrastructure consists of domestic production and processing facilities, LNG export/import terminals and transnational pipelines for imports on the supply side, a cross-country gas network including trunk lines and spur lines and underground storage facilities for storage and transportation, and city gas distribution networks for consumption in domestic, industrial, commercial and transport sectors.

The Petroleum and Natural Gas Regulatory Board (PNGRB) was set up in 2007 under the PNGRB Act (MoLJ, 2006) to regulate cross-country pipeline and city gas distribution (CGD) networks through providing authorisation and determining capacity, tariff and safety standards for these networks. The primary goal of regulation was to ensure adequate, equitable supply across all parts of the country and to promote fair and competitive markets while balancing the interests of consumers and entities engaged in refining, processing, storage, transportation, distribution, marketing and sale of petroleum products and natural gas. Regulation was expected to improve clarity and transparency in the gas infrastructure industry, thus helping to develop a competitive gas market.

However, functioning of the PNGRB has been mired in controversies since its inception, particularly due to confusion regarding the powers of the Board to conduct auctions and authorise entities to lay transportation and distribution networks and to regulate R-LNG terminals.

- The PNGRB Act was passed by the parliament and received presidential assent in April 2006. Following this, the government issued a notification in June 2007 establishing the board but without any members (MoPNG,

2007a). This notification — which was infructuous as the board had no members — was rescinded in October 2007 and a fresh notification issued with the members of the board (MoPNG, 2007b). In the interim, the GoI authorized nine key gas pipeline projects[28] spanning the length and breadth of the country in July 2007 through an opaque process, though it was aware that, once setup, the board was expected to grant authorisations through a transparent competitive bidding process. These pipelines were authorized without definite target dates for start and completion. Five of the nine gas pipelines were not taken up for execution, including all four pipelines granted to RGTIL, whose authorizations were cancelled by MoPNG in 2012. Reasons cited for the delay were lack of demand from city gas distribution projects and non-availability of gas. (CAG, 2015, p. 23; BS, 2012)

- Section 16 of the PNGRB Act, which allows PNGRB to authorise pipeline and city gas distribution networks, was not notified with the rest of the Act, but only notified 3 years after the board was set up. (CAG, 2015, p. 27)
- Section 11(f)(iii) of the PNGRB Act confers powers to the board to monitor and regulate prices of notified products to prevent restrictive trade practices. However, this power is dysfunctional as no products have been notified by the GoI even ten years after notification of the Act. (Anand, 2015)
- Appointments to the regulatory board are made in an opaque manner, calling to question the independence of the board members. (Sreenivas & Sant, 2009)

The government delayed in notifying the Act and its specific sections and products, and used its powers to grant licenses in the interim. These examples show that the government has never really been serious about having an independent, empowered and effective regulator for downstream activities. Lack of clarity regarding some of the basic functions and mandate of the regulator has resulted in bitter battles between the PNGRB on one side and the CGD entities and the GoI on the other, resulting in regulatory uncertainty.

28. Gas Authority of India Limited (GAIL) was authorized to develop five pipelines and Reliance Gas Transportation Infrastructure Limited (RGTIL) the remaining four. RGTIL, which was then a wholly owned subsidiary of RIL, was later converted to a privately held company controlled by Mukesh Ambani, who also heads RIL.

The board's function with respect to consumer protection which is articulated in the PNGRB Act as "protecting the interest of consumers by fostering fair trade and competition amongst the entities" is inconsequential, since the Act doesn't provide the board with powers that would facilitate such a role.

These problems are further compounded by non-availability of domestic gas and uncertainty regarding long-term availability and price of natural gas — uncertainty which played a significant role in slowing down buildout of networks. In this context, several companies won city gas distribution licenses through unrealistic 'zero' bids[29], resulting in negative net cash flows and raising serious questions on the long term viability of these operations (ICRA, 2012). An entity winning the auction with zero bids could either compromise on service, approach the regulator for tariff revision, or bank on unregulated components such as marketing margin to recover its costs and make profits. In addition, it may try to create entry barriers for competitors at the end of the exclusivity period. Since the bidding process has not resulted in real price discovery, it neither guarantees lower consumer tariffs nor efficiency in operations.

7.13 Hydrocarbon Exploration and Licensing Policy (HELP)

In March 2016, the government announced the Hydrocarbon Exploration and Licensing Policy (HELP) to replace NELP for future rounds of exploration bidding. Simultaneously, an Open Acreage Licensing Policy (OALP) will also be operationalised under which E&P companies can bid for blocks at any time by submitting an expression of interest (PIB, 2016).

The high level objectives of HELP appear to be the same as those of NELP, i.e., to enhance domestic oil and gas production for domestic consumption, and to substantially increase investments in the sector. However, there are some important differences.

- There will now be a uniform license for all hydrocarbons, conventional as well as non-conventional.
- The fiscal regime under HELP will be a revenue sharing mechanism as opposed to the profit sharing contract under NELP. This is expected to reduce

29. These bids can be accessed from PNGRB's website at www.pngrb.gov.in/CGD-network-BID.html.

administrative overhead involved in protecting the government's share of the profit such as evaluating prudence in cost recovery and minimising gaming possibilities.

- Government revenue will be calculated based on the pricing guidelines notified by the government or the discovered arms-length price, whichever is higher, potentially dissociating government revenue from any pricing disputes that may arise.
- Marketing and pricing freedom is granted for gas produced from deep water areas, subject to a ceiling based on a formula representing the landed cost of substitute fuels, i.e., imported fuel oil, imported coal, imported naphtha and imported LNG. This is expected to compensate developers for the higher risks involved and to encourage E&P in difficult areas.

While these changes resolve some issues, it remains to be seen how they will impact the pace of exploration and production. There are obvious administrative advantages to the revenue sharing mechanism. However, some experts and industry representatives feel that such a mechanism does not provide sufficient incentives to make risky E&P investments (GoI, 2014, p. 11). In addition, the following issues need to be resolved in order to truly test different licensing regimes:

- There are no proposed changes to the DGH's constitution and functions. Hence, the concerns raised regarding capacity and the independence of the DGH still remain.
- There needs to be greater certainty in contract enforcement to ensure that work plans are undertaken and investments in field development are made as planned. This needs to go hand in hand with greater coordination amongst the different central and state government agencies that are responsible for granting clearances and licenses.
- While details about HELP are not yet available in the public domain, the government will hopefully publish a whitepaper discussing pros and cons of the various approaches considered and the reasons behind the chosen approach in a transparent manner. Given past distrust with the bidding process with concerns regarding asymmetry of information about the blocks on offer, transparency is important to restore investor confidence.
- The DGH also needs to publish more information in the public domain regarding E&P operations such as signed contracts, anonymised bids, exploration activities, field development plans, expected production profiles,

actual production and major decisions made by the MC at the block level. Such transparency will help improve public awareness and trust in E&P activities as well as provide sufficient data for analysts and researchers to study the sector.

7.14 Conclusion and Lessons

The reforms introduced to hasten upstream E&P activities and downstream infrastructure buildout have failed to achieve the stated objectives. As of October 2016, there has been no durable improvement in domestic natural gas production, while the profit sharing mechanism and procedural aspects underlying reforms have been riddled with disputes, resulting in lower investor confidence in the sector.

At the heart of the matter is the GoI's primary objective in conducting auctions, how risk should be apportioned between different stakeholders, how geological uncertainties are dealt with, how the regulatory regime can enforce contracts true to their spirit while balancing the interests of the contractor and the GoI, and what role the price of natural gas is expected to play. Yet, the GoI has not published a comprehensive analysis explaining the pros and cons of the different approaches considered, how each of these approaches are expected to impact natural gas exploration and production, risk apportionment and government take, and the reasoning behind the chosen approach. Such an analysis by the government can help bring all players on the same page, greater policy certainty and consequently greater alignment of objectives.

While there has been eagerness to attract private risk capital, this enthusiasm is not matched with due diligence in ensuring that the right institutional mechanisms are in place to sustain the reforms. The Sundararajan study group observed in 1994 that "the current level of involvement of the private sector is extremely poor owing to problems like lack of adequate data, time lags and delays in the award of contracts etc." (Sundararajan, 1994, p. 6). Some of these impediments to competition and private participation still exist after 16 years of NELP experience. The regulator is not independent owing to its technical advisory role to the government and due to drawing its staff on a rotation basis from National Oil Companies (NOCs). To make matters worse, the regulator appears to lack capacity in dealing with the increasingly complex, technical nature of the sector and took over 20 years to build a national data repository. There is complete lack of transparency in operations and decisions are shrouded in secrecy, leading to massive public distrust.

On the other hand, downstream regulation was doomed to failure from the start with a regulatory design that ensured a toothless regulator, resulting in a lot of confusion among stakeholders and the general public. Failure to increase domestic production has had a cascading effect on the rest of the energy sector, resulting in delays in layout of gas pipeline and distribution networks which in turn led to stunted development of gas markets, and stranded capacity in power generation and fertilizer production. This has had a debilitating effect on downstream reforms resulting in slow down of buildout of midstream and downstream networks.

There has been a consistent lack of transparency and severe governance lapses in the natural gas sector which have led to various kinds of concerns in important areas such as contract enforcement, institutional capacity, regulatory independence, information regarding discoveries and development plans, market concentration, and gas utilisation policy. The Hydrocarbon Exploration and Licensing Policy (HELP), the recently unveiled uniform licensing regime for hydrocarbon exploration and production, is unlikely to deliver unless these issues are sorted out.

8
What's past is prologue[1]

''सिर्फ हंगामा खड़ा करना मेरा मकसद नहीं
मेरी कोशिश है कि ये सूरत बदलनी चाहिए'' [2]

Since the dawn of the liberalisation-privatisation-globalisation era in the early 1990s, the electricity sector has undergone significant changes driven by multiple waves of reforms. The reform era began with the objective of moving away from public sector domination to bringing in private sector investment and expertise. Over time, other objectives such as separation of different arms of the electricity business, introducing competition, introducing independent regulatory institutions, providing universal access to electricity, making distribution utilities viable and promoting renewable energy drove various rounds of reforms.

This has resulted in an electricity sector that may be unrecognisable in some ways to a time traveller from the late 1980s. The monolithic electricity boards of the past have mostly disappeared and instead, we now have different companies managing generation, transmission and distribution in many states. There is a significantly higher participation from the private sector — at least in electricity generation. Independent regulatory institutions have been established to oversee the functioning of the sector. The sector has also grown in sheer size, with electricity generation capacity growing four times and revenue requirements of distribution companies growing nine times during this period. The period has also seen a tremendous rise in the share of renewable energy in the sector.

1. From "The Tempest" by William Shakespeare.

2. "My objective is not just to kick up a fuss, my attempt is to change the future" from the poem *हो गई है पीर पर्वत* by Dushyant Kumar.

However, our time traveller from the late 1980s would also find many things familiar, as they have not changed much in the intervening years. While the proportion of households without access to electricity has roughly halved over these years from about 43% to 21-22%, the absolute number of households without access to electricity has reduced only marginally from 6.4 crores in 1991 to somewhere between 5.5 crores and 5.8 crores in 2016.[3] Similarly, complaints about unreliable power supply, high electricity bills, and poor redressal of grievances would sound familiar. The problems of many interruptions and poor voltage, particularly in rural areas, still persist and it continues to be very risky for enterprises to undertake activities without power generation backup. In spite of greater private sector participation, the borrowings still seem to come from the public sector, mainly through public sector financial institutions. Many distribution companies are still in bad financial health, and technical and commercial losses continue to be high in the case of most distribution utilities. The complaints from social and environmental activists about poor compliance to environmental norms and poor handling of resettlement and rehabilitation have not abated. Most parts of the electricity sector and allied fuel sectors still have highly concentrated market structures with a few dominant conglomerates.

As discussed in the preceding chapters, the reforms have not succeeded to the extent envisaged in meeting the objectives with which they were conceptualised. They have also failed to deliver broader social and environmental goals of equitable and universal access to electricity, and responsible and sustainable development. We conclude the book by summarising why we feel the reforms did not succeed, and use that to draw lessons that can inform the design of future reforms.

8.1 Why did the reforms not deliver as expected?

We classify the various reasons because of which the reforms did not deliver into a few broad themes.

8.1.1 Poorly conceived objectives

One of the primary weaknesses of the reforms was that they were targeted at objectives that had not been sufficiently thought through. Reforms were initiated without a comprehensive critique of what ailed the sector or sufficient public debate to understand all the issues and challenges. Naturally, this ad hoc approach led to

3. Prayas estimate of number of non-electrified households based on rural household electrification data from garv.gov.in/garv2/dashboard (December 2016) and estimation of urban household electrification.

programmes and policies which were designed to deal with the symptoms rather than the root causes of the crisis in the sector.

One illustration of this failure is that the initial focus of reforms was only to attract investments and bring in private sector participation to rapidly increase either electricity generation capacity or fossil fuel production. In particular, bringing in transparent, competitive markets was not an explicit objective of initial experiments. This led to inviting and involving the private sector through discretionary allocation of contracts or resources. Examples include the spate of MoUs signed in the 1990s to increase electricity generation capacity, and the awarding of coal blocks for captive mining (See Sections 2.2 and 6.3.1). Such non-competitive means of deciding winners and losers also resulted in a loss of public trust in how the government introduced private sector participation.

Another illustration of poorly conceived objectives was the insufficient attention given to socially and environmentally desirable goals such as universal access, end-use efficiency, fair resettlement and rehabilitation and minimising environmental damage (See Sections 3.10.3 and 6.4.3). Such goals, which should have underpinned all reform activities, never received the attention they deserved for about a decade. Universal access was explicitly mentioned as an objective only beginning with the Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) programme in 2005. Significant public pressure and increasing prominence of the global environmental problem of climate change was required to bring attention to socio-environmental issues around electricity, though resettlement and rehabilitation of affected communities continues to be a neglected area.

8.1.2 Weak plans and design flaws

Even within the narrow scope of their objectives, the planning and design behind various programmes and policies often suffered from infirmities that led to sub-optimal outcomes. One major weakness in this category was the failure to adopt a comprehensive approach while planning or designing schemes. A glaring example of this failure is the process of competitive bidding for electricity without considering the challenges and issues regarding fuel (coal or gas) supply (See Section 2.4). Similarly, an insufficient consideration of the different interests of state and central governments resulted in sub-optimal design by the central government of bailout schemes for distribution utilities, which are controlled by state governments (See Section 5.6). Another example pertains to power purchase planning by distribution utilities based on demand estimates that do not consider

factors such as the potential of efficiency improvements, latent demand and the dependence of demand on electricity tariff (See Section 5.3).

The second major weakness pertains to poorly designed and articulated laws, policies and contracts. The ambiguous framing of the New Coal Distribution Policy is one major reason for the current spate of generation tariff related disputes in the electricity sector (See Section 6.2), while the Production Sharing Contracts under the New Exploration and Licensing Policy and their interpretation are still being debated more than 15 years after they were introduced (See Section 7.11). Though the 2015 regime for allocation of coal blocks generated much enthusiasm initially, it has not translated into benefits for consumers and the enthusiasm has also rapidly died out (See Section 6.3.2). Such ambiguities not only result in lengthy delays and disputes, but also send negative signals about the sector and thus discourage new players from investing in the sector. Other examples of design weaknesses include the provision for accelerated depreciation (with no incentive to generate electricity) in the wind and solar sectors (See Section 4.2.1) and allowing those with open access or captive renewable energy plants to unduly benefit from the Renewable Energy Certificate mechanism until recently (See Section 4.5.4). In these cases, project developers benefited from the scheme with no corresponding benefit in terms of efficiency or social gains.

The third weakness in this category relates to insufficient thought given to operational and management issues while designing policies and programmes. Thus, the RGGVY (and its successor, the Deen Dayal Upadhyay Gram Jyoti Yojana or DDUGJY) programme design did not factor in possible increase in productive loads once villages were connected (Section 5.7.2). Many programmes neglect the key issue of independent monitoring and verification, without which programmes are unlikely to achieve their objectives. The DDUGJY, Accelerated Power Development and Reforms Programme (APDRP), Restructured-APDRP and the various bailout programmes for distribution utilities can be cited as examples of schemes that did not include a mechanism to independently verify the progress of the schemes (See Section 5.6.2). Another example of such neglect is the poor monitoring of, and therefore compliance to, environmental management plans (See Sections 3.10.3 and 6.4.3).

8.1.3 Weak institutions

Effective implementation of any policy or programme requires well designed, capable and competent institutions to execute it. However, this aspect is often

neglected while designing reform measures and hence the reform measures do not perform as intended.

Many institutions have shortcomings which prevent them from fulfilling their role. Among regulatory institutions, the Petroleum and Natural Gas Regulatory Board (PNGRB) is perhaps the best example of an institution that was never meant to perform effectively, since its role was defined so narrowly (See Box 7.1). The Directorate General of Hydrocarbons is not designed to be an independent agency and hence has limited abilities to regulate the upstream hydrocarbon sector. The coal sector has no institution at all to perform an independent regulatory activity, while the Coal Controllers' Organisation — which is expected to oversee mine operations — is severely short of staff and budget and does not have adequate authority (See Section 6.4.2). Regulatory failures in the financial sector have impacted the electricity sector as seen with the current crisis of non-performing assets accumulated with public sector banks. In the electricity sector, though the regulatory institutions are relatively better designed, there are serious question marks around their effectiveness and independence.

Institutional weaknesses are not limited to regulatory agencies. The lack of capacity and autonomy of agencies such as the Central Electricity Authority (CEA) and publicly owned distribution utilities, subsuming the Load Despatch Centre function within the transmission utilities, the lack of capable institutions to oversee energy efficiency in states, and the insufficient coordination until recently among closely related ministries such as power and renewable energy are other examples of institutional weaknesses in the Indian electricity sector. Such fundamental weaknesses in institutions raise the question of whether there is any serious commitment to building robust institutions that can fulfil their roles in an independent and competent manner.

Not surprisingly, institutions have often failed to fulfil their mandates. Regulatory institutions have been lax in enforcing contracts in the electricity sector, and have been open to considering renegotiation of contracts based on competitively discovered tariffs (See Section 2.4). They have been ineffective at holding distribution companies accountable for power purchase planning, universalisation of electricity access, quality of supply and compliance with Renewable Purchase Obligations (See Section 4.5.1). The various sector actors have not been able to build the capacity of civil society to be able to participate and utilise opportunities to intervene in policy and regulatory matters. Another example is the inability of

the Coal Controllers' Organisation to monitor production from coal mines. There have also been failures of oversight from various institutions such as the inability of State Pollution Control Boards to enforce pollution control norms and the inability of Electricity Regulatory Commissions to ensure that cost-plus electricity producers stick to stated efficiency norms (See Section 2.5). There is little evidence of coordination and collaboration among regulators in related sectors such as, say power and coal, or power and financial institutions. Such an inability to fulfil their mandate is either due to internal shortcomings (of capacity, budget etc.) and/or due to external pressures that induce them to turn a blind eye to such violations.

It is also telling that, through the proposed amendments to the Electricity Act, the government is considering the introduction of competition and markets in electricity supply, without a clear understanding of the institutional functions required to oversee the development and oversight of such markets.

The electricity sector is a dynamic sector, particularly so with increasing penetration of fast changing renewable technologies. In such a situation, there is a need for both planning and regulatory institutions to be proactive and anticipate changes, so that they can deal with changing conditions. However, the Indian electricity sector is replete with examples where it has been reactive rather than proactive. The financial unsustainability of distribution utilities should have been apparent and corrective measures initiated based on discussions with states, well before the situation became too serious to ignore (See Section 5.6). Forecasting and scheduling for renewable energy is another issue that had been hanging fire for many years with little progress towards operationalising it until recently (See Section 4.5.6). Major developments in the coal sector, such as the framing of the NCDP and passage of the Coal Mines (Special Provisions) Act were in response to adverse judgements from the Supreme Court rather than as proactive initiatives (See Section 6.5).

8.1.4 Insufficient competition

One particular aspect which was critical to the success of reforms but whose development has been rather stunted is the institution of competitive markets. Though some aspects of the electricity sector such as the 'wires' component of transmission and distribution may be natural monopolies and not conducive to competition, many other elements of the electricity and fuels value chain continue to have highly concentrated market structures even twenty-five years after reforms were introduced.

The coal sector continues to be dominated overwhelmingly by Coal India Ltd. In spite of opening up for competition, the upstream oil and gas sector is dominated by two players – ONGC and RIL (See Section 7.5.1). Though the private sector's share has rapidly increased in conventional power generation, the number of players is still very limited for a country the size of India. For example, of the nearly 42,000 MW of capacity contracted through competitive bidding up to 2011, about 65% of capacity was developed by just four promoters (See Section 2.4). In the renewables space, while the solar sector has been highly competitive so far, the wind sector has been characterised by vertical integration and few suppliers (See Section 4.5.2) though the government has very recently announced plans to introduce competitive bidding for wind too. While there has been a conscious attempt to 'unbundle' publicly owned erstwhile state electricity boards and get their distribution arms to procure power competitively, many privately owned distribution utilities still purchase power only from affiliate generation companies through a 'cost-plus' route — in other words, while there is a push to dismantle public monopolies, private monopolies have been let off relatively easily (See Section 5.4.2). Other examples of limited competition include the reducing number of bidders per block for oil-and-gas exploration across rounds and the small number of bidders per block for the coal block auctions attempted in 2015 (See Section 6.3.2).

There could be multiple reasons for this lack of competition. One reason could be that the terms on offer were not attractive enough for investors, as has been claimed in the recent attempts at auctioning UMPPs and oil-and-gas blocks. Another reason could be that many interested parties found the entry barrier too high in terms of technical or financial capability, though it is difficult to find any examples of this. A third reason could be that many interested parties felt that the competition would not be fair, and hence did not think it worthwhile to participate in these processes. Whatever the role played by each of these factors, it is fair to say that the end result is that the efforts to promote competitive markets have not really succeeded.

It would be instructive to analyse and understand the reasons behind the success of competition in the solar sector, to see if those lessons can be applied to other sectors. Preliminary analysis suggests a few reasons. The sector is relatively new with established players (private and public) having little expertise, making it easier for newer entrants. There is little information asymmetry in the sector because of reasonably uniform and predictable resource availability — a significant difference from other resources such as wind or fossil fuels. The incentives and market structure were oriented towards genuine competition quite early — for example,

through tariff-based competitive bidding. Unlike wind, the sector was not vertically integrated with project developers being different from panel manufacturers and others in the value chain, with each element being competitive in itself. Low running costs due to the absence of any fuel reduces risks considerably and allows for greater certainty of price through the project lifetime. Another factor which could have helped is the modular nature of the solar sector, which has allowed players of various sizes to enter the market.

8.1.5 Entrenched vested interests

One of the fundamental reasons behind the weaknesses discussed above (regarding objectives, plans and policies, institutions and competition) is the strong likelihood of the presence of vested interests in the sector. Their primary objective was to reap the benefits of opening up an investment-heavy sector rather than being efficient or accountable. While it is obviously difficult to produce concrete evidence in support of such a hypothesis, there are many indicators suggesting that it may not be far-fetched.

The spate of MoUs signed during the IPP era for capacities far in excess of what was deemed required and at prices that were not economical is one strong indicator in that direction (See Section 2.2). The allocation of captive coal blocks and coal linkages to one among many applicants through opaque criteria is another such indicator, further buttressed by the report of the Comptroller and Auditor General and the Supreme Court judgement (See Sections 6.2, 6.3.1). The serious weaknesses in the design of PNGRB, the granting of nine pipelines just before the enactment of the PNGRB Act (See Box 7.1) and the large number of MoUs signed by NTPC with distribution utilities just before the competitive bidding for power procurement became mandatory are further pointers in this direction. The silence of all the other players in the sector while such clearly non-competitive decisions were being taken is reminiscent of the famous parable of the dog that did not bark[4], and indicates that all those involved were happy be part of the game as it was being played rather than trying to rectify it.

In a way, it is perhaps not surprising that such vested interests came to occupy significant parts of the sector, given the previously discussed weaknesses in institutions, laws, policies and systems (which could together be loosely called

4. The "curious incident of the dog in the night-time" from "The Adventure of Silver Blaze" by Arthur Conan Doyle.

'governance'). This begs the chicken-and-egg question of whether weaknesses in governance provided a fertile ground for vested interests to emerge, or whether vested interests ensured that governance would remain weak for them to flourish. Perhaps the truth is somewhere in between – that is, as with real chickens and eggs, they co-evolved through a process of positive feedback that reinforced each other to the detriment of the sector.

Assuming this hypothesis to be true, such interests, operating in tandem with the government machinery, would have many deleterious impacts on the sector. They would skew the rules of the game reducing competition, discouraging new investors and inhibiting accountability. The net result is that privatisation may not result in any efficiency gains (indeed, efficiency may even reduce) and costs would continue to be high. By and large, this seems to be consistent with the situation in the Indian electricity sector despite about 25 years of reforms.

The one happy exception to this is perhaps the grid connected solar photovoltaic segment. Here, the competition has been fierce with a large number of players participating in the bidding process and many winners emerging from it (See Section 4.4). Moreover, so far there has been little suspicion of rigged bidding and no requests for post-facto contract revision. In addition to factors such as rapid technology improvements and an international supply glut, we believe this intense competition has been an important factor behind solar prices in India falling as rapidly as they have. One hopes that this good beginning in the sector is carried forward, and electricity consumers actually benefit from the low tariffs discovered. One also hopes that similar good practices will be followed in other parts of the solar energy space such as rooftop solar, solar thermal and agricultural pumps.

8.2 What can one learn from the experience so far?

Since the attempts at reforms over the last 25 years have generally not delivered, what lessons can be learnt from them, and how can future reforms be designed to avoid these pitfalls?

One school of thought would say that reforms should be abandoned and one should go back to a sector controlled by public sector units (PSUs). While a PSU dominated electricity sector is an unrealistic expectation in the current global political economy, it would also not be desirable since PSUs have their own inefficiencies and problems. With the implicit or explicit backing of the government, regulators find it difficult to hold such organisations accountable, as has been the case with the

poor station heat rates of public sector generators (See Section 2.5) and poor record of public distribution utilities with respect to controlling their costs, quality of supply, access, metering and billing (See Section 5.9). Similarly, many inefficiencies of the coal sector can be traced back to the industrial structure with Coal India Ltd. (CIL) as the monopoly supplier.

Having said that, given the nature of the electricity sector and the reality of the Indian political economy, one should also temper one's expectations about markets being able to solve all the problems of the sector. Firstly, the entire electricity sector may not be amenable to competition and markets, with segments such as transmission and the 'wires' part of distribution being considered natural monopolies. Secondly, the record of privatisation in the electricity sector and resultant improvements in efficiencies and reduction in costs is mixed at best, even in countries with better institutions and more robust markets than India. Thirdly, creating competitive markets requires suitable institutional design and maturity, much more transparent systems and a more accountable political economy, all of which are still in their infancy in India. Finally, the state, regulatory agencies and public sector organisations will have an important role in addressing the prevalent concerns of energy poverty, inequity, poor quality of supply, and weak socio-environmental processes.

With the increased thrust on privatisation and the belief that there is a minimal role for the state and PSUs in the future, PSUs have been generally neglected over the past two decades. At the same time, some PSUs have also been used conveniently by the state to suit their ends through measures such as giving free or subsidised electricity to agricultural and domestic consumers, buying short -term power during elections, not disbursing subsidies to distribution companies in a timely manner, and issuing a presidential directive to CIL to sign Fuel Supply Agreements. However, as exemplified by the failure of the Odisha privatisation exercise following the premature retreat of the state (See Section 5.2.1), the reality is that the public sector, private sector and the state all have important roles to play in the Indian electricity sector. Given this reality, how can one achieve the desired social, economic and environmental objectives for the sector? We present some suggestions that may be classified under the broad umbrella of 'governance', because that is where we think the biggest weaknesses are. If these suggestions are adopted and implemented, there is a high likelihood that good substantive solutions will emerge to effectively address the challenges.

8.2.1 Clear prioritisation of social and environmental objectives

Dealing with socio-environmental impacts is often a supplementary objective, if at all, of many policies and programmes. Similarly, affordable and reliable access to electricity is only recently being talked of as an important objective of electricity programmes. As a result, these issues also receive secondary treatment in the design of policies and programmes. Instead, sustainable and equitable development requires that these issues should be as important as other objectives of improving competition or achieving efficiency. Examples of such objectives which should be explicitly stated and tracked include universal access to affordable modern energy, provision of reliable electricity supply, equitable treatment of the needs of all competing uses and users of common resources such as water or common land, equal or better quality of life for those displaced or affected by energy projects, and complete restoration of the land and ecosystem at the end of a project's life.

These objectives should not only receive priority in policies and programmes, but should be backed by measures and instruments to achieve them. For example, providing reliable electricity supply during evening hours to households and during the day-time to farmers (when it is most needed by them) requires suitably designed electricity policies and pricing mechanisms.[5] Similarly, equitably satisfying the needs of competing uses and users of common resources requires much more robust frameworks to assess such competing needs than are currently followed.

In addition to targeted policy measures and instruments, programmes should also contain credible means of tracking and monitoring progress and/or compliance towards the objectives, along with ways to highlight and correct any deviations. Publishing periodic reviews of such tracking and monitoring efforts will be useful as they can then be subject to public scrutiny. Involving local citizens, who are likely to be the most interested and affected stakeholders, in such scrutiny and monitoring would be highly desirable. In addition, given the complexity and diversity of India, uniform one-size-fits-all solutions are unlikely to work. Therefore, there is a need to tailor such programmes to different local contexts, which is perhaps best done by actively involving the concerned states and other local stakeholders in the programme design itself.

5. See (Sreekumar, Josey, Chitnis, & Dixit, 2013; Gambhir & Dixit, 2015) for suggestions regarding such measures.

8.2.2 Agile and comprehensive planning

Given the characteristics of the electricity sector such as its capital intensive nature, long gestation periods, and impact on significant 'commons' resources such as water, air and community land, planning is a function that cannot be wished away even if the country had fully competitive markets. However, planning as currently practised in the electricity sector is typically by rote and done in silos, rather than being comprehensive, estimating need, anticipating change and preparing for it.

To effectively guide the electricity sector, the nature of planning needs to undergo a significant change. It needs to become more comprehensive — that is, it should consider the interlinkages and interactions with all related sectors such as fuels, environment, financial institutions, railways and state governments. Some recent government initiatives (e.g. Swachh Bharat Abhiyan) are designed to be cross-ministerial — a similar approach needs to be taken for electricity sector policy formulation.

A pre-requisite for effective and comprehensive planning is the collection, collation and dissemination of rich data in a timely manner to not only aid in such planning but also in programme monitoring and investment-related decision making. Unfortunately, the current situation in India is that data is fragmented, inconsistent, not easily accessible and significantly outdated. Addressing this requires recognition of data management and its public availability as an important function, strengthening the capacity of the relevant agencies, and regular coordination across the various data agencies to collate and reconcile data from multiple sources.

Planning also needs to become much more agile. As the pace of change of technology and businesses in the electricity sector increases, planning can never fully anticipate the future. Therefore, it is necessary to be agile and nimble, to continually monitor the changes taking place in the country (and the world) and respond to them appropriately. In particular, it would be better to have a long-term vision with plans for shorter horizons which are revisited and revised frequently, rather than have rigid long term plans or policies that are rarely revisited.

Both these aspects, of being comprehensive and agile, would become easier if planning followed a much more open and participative process of engaging with experts and stakeholders from outside the government and industry, as they may bring useful insights to the process.

8.2.3 Transparent, accountable and effective institutions

Adequately empowered and accountable governing, planning and regulatory agencies, supported by informed public participation, are essential pre-requisites for an effective electricity sector.[6] Accountability of such institutions can only result from enshrining autonomy and complete transparency in their operations, providing adequate spaces for public participation and enabling citizens to constructively use such spaces — in other words, deepening democratic processes.

While transparency levels have generally improved across the sector over the last two decades, there is room for further improvement. On the one hand, there seems to be a built-in resistance to publishing information in an easily accessible manner (e.g. oil-and-gas discoveries, some aspects of the recent coal block allotments, and even something as simple as a list of all the clearances and approvals required for various kinds of activities). On the other hand, even where there is intent to publish information, the systems and processes to collect and disseminate information in a timely and useful manner are very weak, making it difficult to effectively use the information. Such shortcomings can easily be fixed with minimal financial or human resource cost, if it is recognised as a problem worthy of being addressed.

Capacity is another major challenge of government and regulatory agencies if they are to become effective. Without significant investment in their own capacity building, such institutions cannot deal with the challenges arising in a fast-changing sector, and will be vulnerable to taking decisions based on insufficient understanding. For example, electricity regulatory commissions and the Directorate General of Hydrocarbons often rely on staff of the public sector entities they regulate, which is clearly not desirable. The ministries in governments — particularly in states but also at the centre — are barely equipped to perform their routine tasks, leave alone planning for a dynamic future or dealing with the kind of challenges faced by India.

In a situation where the state and state-owned companies are a major part of the sector, there is a need for independent regulatory agencies to provide the necessary checks and balances, and be in a position to not be swayed by immediate political expediency. Currently, regulators in the electricity sector are nominally independent as defined in the Electricity Act, but in reality, their independence is questionable given the processes for their appointments and operations. The fuel sectors are even

6. This includes regulation and oversight of related sectors such as fuels, environment and financial institutions. The question of whether one should have a unified energy regulator or different regulators for different sub-sectors needs to be debated further.

worse, with no really independent regulator at all though it is something which should be considered seriously, particularly as these sectors move towards more market-oriented structures. True independence of regulatory agencies can only be assured if appointment processes are such that allegiance to the government is not a requirement to be appointed, and such agencies are given sufficient financial and operational autonomy so that they can build up their capacity in the sector.

Electricity regulators are expected to be accountable to the respective legislatures. However, it is not clear that legislatures take an active interest in the functioning and effectiveness of regulators, thus making this accountability mechanism ineffective. This can only be addressed if legislatures actively monitor the performance of regulators and urge them to improve their functioning.

8.2.4 Participative policy formulation and regulation

Ambiguous and unclear policy and contractual documents have been one of the banes of the sector leading to multiple litigations. Adopting a rigorous and deliberative approach to formulating policies and contracts would help to address this. Rather than putting together a policy or contract in haste and repenting at leisure at various litigation forums, it would be better to take more time during drafting of the policy or contract, and ensuring that most possibilities have been covered and that the interests of the diverse stakeholders are represented.

Of late, some ministries in the central government have begun the welcome step of publishing draft policies and contracts, and seeking comments from the public about them. This should be further improved and strengthened in a few ways. Firstly, more agencies — such as state governments and other central agencies — should adopt this practice. Secondly, the draft document itself should be prepared after consultation with a variety of stakeholders from the producing, consuming and affected parties. Thirdly, rather than just passively seeking comments from the public (by publishing an announcement on the website that may be missed by many), comments should be sought actively by reaching out to stakeholder groups and issuing advertisements in prominent newspapers around the country and making the draft available in local languages. Fourthly, depending on the complexity of the documents being published, sufficient time should be allotted to people to provide comments — at present the time provided is often very limited which leads to broad brush comments of insufficient depth. Finally, the government should not only publish a final document based on the comments received but also publish a gist of the comments received along with its response to each of them. These steps

will help to ensure that policies and contracts are much more robust. After going through such a consultation process, they will also be less vulnerable to multiple interpretations and litigations.

In the case of contracts and concession agreements, particular attention should be paid to factors such as fairness, balancing the interests of the investor, the government and society, protecting the environment, and the feasibility of managing and enforcing the contract. Once again, these objectives are easier to achieve if these documents are made based on broad public consultation. For example, the problems with one-sided Fuel Supply Agreements in the coal sector or the complications surrounding the Production Sharing Contracts in the oil-gas sector are less likely to have arisen if these contracts had benefited from inputs of the concerned stakeholders.

Public participation and consultation continues to be an Achilles heel of regulatory processes. Not all electricity regulators conduct public processes even for important issues such as tariff determination — this should be corrected. Additionally, electricity regulators should invest in building the capacity of citizens and citizens' groups to intervene and constructively participate in regulatory processes. There have also been concerns about the quality of public hearings conducted as part of Environment Impact Assessments, which need to be addressed. To address these weaknesses, there is a need for governments and regulators to invest in creating and sustaining citizens' organizations to perform crucial functions such as independent monitoring and verification, and representing citizens' and small consumers' issues at regulatory forums.

8.2.5 Enhancing competition

As discussed earlier, there are strong indications that the playing field in the Indian electricity sector is skewed in favour of some players who can 'manage the system'. Whether or not this is true, even such a perception is harmful to the development of truly competitive markets as many genuine and interested parties (both Indian and foreign) may choose to keep away from the Indian sector because of this perception. Therefore, it is important to set up mechanisms and processes to ensure that all parties are treated equally and to send out a clear message that this is indeed the case.

To this end, the first pre-requisite is complete transparency and ensuring that there are no information asymmetries among the various market participants. Rules, processes and contracts should be made clear to everybody, and should be applied

similarly to all parties. Moreover, all parties should be made to feel confident that this is indeed the case. Entry and exit barriers should be reasonable and similar for all parties. International best practices for the relevant sector should be studied and adapted for Indian conditions to encourage genuine competition. Restrictions could be considered on the maximum market share of one participant to reduce concentration and deepen markets — similar to what was belatedly done for UMPP bidding — so that the kind of concentration seen in the upstream oil-gas sector or thermal power generation is prevented. Some of these precautions are particularly relevant if the existing market structure already has a few dominant players who may potentially abuse their position to distort the market.

Proactive measures to prevent anti-competitive and inefficient practices would help to enhance healthy competition. For example, unviable bids should be identified early and rejected, and unviable projects should be identified early and weeded out. This will help to prevent the kind of problems currently being faced by the sector of some players becoming 'too big to fail' and hence needing to be rescued with public money. Similarly, practices such as signing a spate of MoUs with National Thermal Power Corporation just before opening up the electricity generation sector, granting of pipelines to Gas Authority of India Ltd. and Reliance Industries Ltd. on the eve of passing the PNGRB Act, and acceptance of extremely aggressive bids that are patently unviable send out negative signals regarding the 'access' needed to enter the sector and reinforce the message that the field is skewed in favour of some.

8.2.6 Improving efficiency of sector actors

Efficiency of sector actors can be improved in one of two ways: one, having genuinely competitive and functional markets and two, closely monitoring their performance, benchmarking it to standards and holding them accountable for improvements.

The first approach has been discussed extensively elsewhere. The second approach is particularly relevant in cases where competition is not easily feasible (e.g. the 'wires' or distribution business) or where, for legacy reasons, there are actors who are guaranteed returns on their investments (the so-called 'cost-plus' businesses). Many, but definitely not all, such actors are public sector companies. Regarding the private sector actors in these segments, such as privately owned distribution companies or, in some cases, private sector owned cost-plus power generators, much more effective regulatory oversight and holding them accountable to performance improvements is required than is currently practiced.

The public sector will continue to play an important role in the Indian electricity sector for various reasons discussed earlier. Hence, improving its efficiency and accountability — to meeting both performance as well as social goals — is important. One step towards this could be to give them greater autonomy regarding routine operational and technical decisions while retaining control over the overall strategic direction. Their performances could be continually benchmarked against equivalent global practices, and they could be given targets to gradually improve their efficiencies to match such benchmarks. Their capacities should be built up by bringing in greater technical and professional expertise. Allowing regulatory agencies to perform their duties without fear or favour, and holding PSUs accountable for their performance and social mandates will also help to improve them. With sufficient investment in improving their operating practices and performance, they could gradually be exposed to greater competition, so that competitive pressures help to keep them on their toes and ensure continuous improvement. Needless to say, this can only happen if there is sufficient political will and commitment.

8.3 Conclusions

To conclude the book, the key question to answer in order to make reforms work in the electricity sector is not whether to privatise more, faster or better. Instead, it is to ask how one can build systems and processes that will yield desirable social, economic and environmental outcomes. Thus, it is less about the ownership of enterprises — public versus private — and more about how one ensures that they perform effectively, deliver efficiency improvements and provide reliable and affordable electricity in an equitable and sustainable manner.

We believe that the set of suggestions — necessarily broad in nature — outlined in the preceding pages will help to move in this direction. However, to do so, it should be recognised and accepted that the state, transparently informed and guided by various stakeholder groups including citizens, will continue to have a critical role to play in shaping and administering the electricity sector. It may do this not only as an active participant but more importantly as a capable, non-partisan referee working in the larger public interest, who is seen to be so. Until that Gordian knot is opened, a healthy and vibrant electricity sector in the country will sadly remain a mirage.

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Chapter 5 - Electricity distribution: On square one, even with reforms after reforms

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Chapter 6 - The Indian coal sector: A black past and a grey future

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Acronyms

ABR	Average Billing Rate
ABT	Availability Based Tariff
ACoS	Average Cost of Supply
AD	Accelerated Depreciation
ADB	Asian Development Bank
AMR	Automatic Meter Reading
APDP	Accelerated Power Development Programme
APDRP	Accelerated Power Development and Reform Programme
APPC	Average Power Purchase Cost
APTEL	Appellate Tribunal for Electricity
AT&C Loss	Aggregate Technical and Commercial Loss
ATE	Appellate Tribunal for Electricity
BCM	Billion Cubic Meters
BEST	Brihanmumbai Electric Supply & Transport Undertaking
BHEL	Bharat Heavy Electricals Limited
BPL	Below Poverty Line
BSES	Bombay Suburban Electricity Supply Company
BU	Billion Units
CAG	Comptroller and Auditor General of India
CAGR	Compounded Annual Growth Rate
CCGT	Combined Cycle Gas Turbine
CCI	Competition Commission of India
CCO	Coal Controllers' Organization
CDM	Clean Development Mechanism
CEA	Central Electricity Authority
CER	Certified Emission Reduction
CERC	Central Electricity Regulatory Commission
CESC	Calcutta Electric Supply Corporation
CESU	Central Electricity Supply Utility of Odisha
CGPL	Coastal Gujarat Power Ltd.
CIL	Coal India Limited
CMNA	Coal Mines (Nationalisation) Act

CMSPA	Coal Mines (Special Provisions) Act
CNG	Compressed Natural Gas
CPA	Central Plan Assistance
CPCB	Central Pollution Control Board
CPP	Captive Power Plant
CSP	Concentrating Solar Power
CSS	Cross-Subsidy Surcharge
CTU	Central Transmission Unit
CUF	Capacity Utilisation Factor
CWC	Central Water Commission
DAE	Department of Atomic Energy
DDUGJY	Deen Dayal Upadhyaya Gram Jyoti Yojana
DERC	Delhi Electricity Regulatory Commission
DGH	Directorate General of Hydrocarbons
DISCOM(s)	Distribution Company/(ies)
DSM	Deviation and Settlement Mechanism
DT	Distribution Transformer
E Act	Electricity Act, 2003
EAC	Expert Appraisal Committee
EIA	Environmental Impact Assessment
E&P	Exploration and Production (typically refers to oil and gas resources)
FDI	Foreign Direct Investment
FICCI	Federation of Indian Chambers of Commerce & Industry
FiT	Feed in Tariff
FoR	Forum of Regulators
FRP	Financial Restructuring Plan
FSA	Fuel Supply Agreement
FSTA	Fuel Supply and Transport Agreement
GBI	Generation Based Incentive
GENCO	Generating Company
GHG	Green House Gas
GLOF	Glacial Lake Outburst Floods
GoI	Government of India
GSECL	Gujarat State Electricity Corporation Limited

GSPC	Gujarat State Petroleum Corporation
GW	Giga Watt
HELP	Hydrocarbon Exploration and Licensing Policy
HEMM	Heavy Earth Moving Machinery
HT	High Tension
HVDS	High Voltage Distribution System
IEGC	Indian Electricity Grid Code
IEX	India Energy Exchange
IM	Investment Multiple
IMF	International Monetary Fund
INDC	Intended Nationally Determined Contributions
IOC	Indian Oil Corporation
IPDS	Integrated Power Development Scheme
IPP	Independent Power Producers
IPPAI	Independent Power Producer Association of India
IREDA	Indian Renewable Energy Development Agency
ISTS	Inter- State Transmission System
IWPA	Indian Wind Power Association
JNNSM	Jawaharlal Nehru National Solar Mission
kV	kilo-volt
kVA	kilovolt-ampere
kWh	kilo Watt hour, or Units - unit for electricity consumption
LDC	Load Despatch Centre
LNG	Liquefied Natural Gas
LoA	Letter of Assurance
MC	Management Committee
MDO	Mine Development Operator
MERC	Maharashtra Electricity Regulatory Commission
MMDRA	Minerals and Mines (Development and Regulation) Act
mmscmd	Million Metric Standard Cubic Meters per Day
MMT	Million Metric Tonnes
MNES	Ministry of Non-Conventional Energy Sources
MNRE	Ministry of New and Renewable Energy
MoC	Ministry of Coal

MoEF	Ministry of Environment and Forests
MoEFCC	Ministry of Environment, Forest and Climate Change
MoP	Ministry of Power
MoPNG	Ministry of Petroleum and Natural Gas
MoU	Memorandum of Understanding
MSEDCL	Maharashtra State Electricity Distribution Company
MTPA	Million Tons Per Annum
MW	Mega Watt
MWP	Minimum Work Programme
MYT	Multi-Year Tariff
NAPCC	National Action Plan on Climate Change
NCDP	New Coal Distribution Policy
NCEF	National Clean Energy Fund
NDC	National Development Council
NELP	New Exploration Licensing Policy
NHPC	National Hydro Power Corporation
NIWE	National Institute of Wind Energy
NLDC	National Load Dispatch Centre
NOCs	National Oil Companies
NRRP	National Resettlement and Rehabilitation Policy
NSM	National Solar Mission
NTP	National Tariff Policy
NTPC	National Thermal Power Corporation
OA	Open Access
OALP	Open Acreage Licensing Policy
OERC	Odisha Electricity Regulatory Commission
OIL	Oil India Limited
O&M	Operation and Maintenance
ONGC	Oil and Natural Gas Corporation
PEL	Petroleum Exploration License
PFA	Power For All
PLF	Plant Load Factor
PNG	Piped Natural Gas
PNGRB	Petroleum and Natural Gas Regulatory Board

POC	Point of Connection
POSOCO	Power System Operation Corporation
PPA	Power Purchase Agreement
PPAC	Petroleum Planning and Analysis Cell
PSC	Production Sharing Contract
PTC	Power Trading Corporation India Limited
PV	Photovoltaics
PXIL	Power Exchange India Limited
RAC	Regulatory Asset Charge
R-APDRP	Restructured - Accelerated Power Development and Reforms Programme
R&R	Resettlement and Rehabilitation
RBI	Reserve Bank of India
RE	Renewable Energy
REC	Renewable Energy Certificate
RERC	Rajasthan Electricity Regulatory Commission
RESCO	Renewable Energy Service Company
RGGVY	Rajeev Gandhi Grameen Vidyutikaran Yojana
RGO	Renewable Generation Obligation
RIL	Reliance Industries Limited
R INFRA-D	Reliance Infrastructure Limited-Distribution
RoR	Rate of Return also Run of River (hydropower project)
RPO	Renewable Purchase Obligation
RRF	Renewable Regulatory Fund
RSPM	Respirable Suspended Particulate Matter
RTI	Right to Information
RTPV	Rooftop Solar Photovoltaics
RVP	River Valley Projects
SANDRP	South Asia Network on Dams, Rivers and People
SCCL	Singareni Collieries Company Limited
SDG	Sustainable Development Goals
SEB	State Electricity Board
SECI	Solar Energy Corporation of India
SERC	State Electricity Regulatory Commission
SHP	Small Hydro Power

SIA	Social Impact Assessment
SLC (LT)	Standing Linkage Committee (Long Term)
SoP	Standards of Performance
STU	State Transmission Utility
Tcf	Trillion Cubic Feet
T&D	Transmission and Distribution
TNERC	Tamil Nadu Electricity Regulatory Commission
ToR	Terms of Reference
TPC-D	Tata Power Company- Distribution
TPL	Torrent Power Limited
TRANSCO	Transmission Company
UDAY	Ujwal Discom Assurance Yojana
UI	Unscheduled Interchange
UMPP	Ultra Mega Power Project
UNFCCC	United Nations Framework Convention on Climate Change
UPERC	Uttar Pradesh Electricity Regulatory Commission
USO	Universal Service Obligation
WBERC	West Bengal Electricity Regulatory Commission
WBSEDCL	West Bengal State Electricity Distribution Company Limited

Glossary

Accelerated Depreciation (AD)	It allows for depreciation of fixed assets at a fast rate early in their useful lives, thereby reducing taxable income in initial years and deferring tax liabilities. This can only be availed by profit making companies to offset their tax liabilities.
Aggregate Technical and Commercial (AT&C)	It is a measure of total losses in the distribution network and has two components – technical and commercial. It is the difference between electricity available for sale and electricity for which payments are received. Some amount of technical loss is inevitable when electricity flows in the network. Commercial loss is electricity loss on account of theft, improper metering and billing and poor collection of bills.
Availability Based Tariff (ABT)	It is an arrangement to rationalise tariff for supply or withdrawal of power from the grid. In the context of generators, it has three components, (a) capacity charge, linked to the plant's declared capacity to supply MWs, to reimburse the fixed cost of the plant, (b) energy charge for scheduled generation to reimburse the fuel cost and (c) a payment for deviations from schedule, at a rate dependent on grid frequency. It can also be applied to bulk buyers, in which case, generation is replaced by withdrawal.
Average Billing Rate (ABR)	It is a measure of the average revenue realised per unit of electricity sold. It is usually calculated for each consumer category and also for total sales.
Base Load	It refers to the minimum continuous level of electricity demand (load) during a day. Base load is usually met through coal and nuclear power plants.
Captive coal block	A coal block associated with a specific end-use plant.
Carriage and content	It refers to two separate functions of electricity distribution. Carriage (also called 'wires') refers to the physical infrastructure required to supply electricity such as distribution transformers, cables, poles etc. Content (also called 'supply') refers to the electricity that is supplied through the physical infrastructure.
Coal-gate scandal	A scandal relating to the inappropriate allocation of captive coal blocks, brought to light by the audit report of the Comptroller and Auditor General (CAG) of India.
Coking coal	This refers to high calorific value coal usually used in the steel industry.
Consumer Grievance Redressal Forum (CGRF)	A forum set up by the distribution company to address consumer grievances. It typically has four members, of which three are appointed by the company and the fourth by the state regulatory commission to represent consumers.

Consumer representatives	Persons authorised as per Section 94(3) of the Electricity Act, 2003 to represent interests of consumers in proceedings before the regulatory commission.
Cost petroleum/ Cost recovery	In the context of oil and gas exploration and production contracts, cost petroleum is the amount of costs recoverable by the contractor from annual revenues from production of oil/gas.
Cross-Subsidy Surcharge (CSS)	It is a surcharge levied on open access consumers to compensate the distribution company for loss of cross-subsidy due to migration of such subsidy providing consumers to open access.
Design energy	It is the quantum of energy which can be generated in a 90% dependable year with 95% availability of the installed capacity of the hydro generating station.
Distribution circle	It is an administrative unit of a distribution company, typically covering a district or part of a large city.
Downstream	It generally refers to energy supply activities related to energy resource manufacturing, marketing and distribution. Typically used in the oil and gas sector, downstream refers to transformation through refining and fractionation, distribution through pipelines, rail, road and other transport, and sales and service to end users. Sometimes, refining and transportation is referred to as midstream, and sales and service are referred to as downstream.
Electricity Act (E Act) 2003	It is a law enacted in 2003, which replaces all previous electricity acts and provides the legal framework for the Indian electricity sector.
End-use plant	As per the Coal Mines (Nationalisation) Act, 1973, it is a plant using coal for a specified end-use such as production of iron and steel or generation of power or other such uses as may be notified by the Central Government from time to time.
Energy banking	In the context of renewable energy, energy banking refers to an incentive for renewable energy generators under open access/ captive transactions. In case of surplus (generation being higher than consumption in the same Time of Day slot), it can be notionally banked/credited with the host distribution company. This surplus can be offset at a later stage during the banking period – usually one year. This is especially important for wind power given its seasonal profile.
Feeder separation	It is a mechanism to separate the agricultural load from other loads, especially residential, connected to an existing feeder. It is achieved by isolating all agriculture load on a separate new feeder. Such an arrangement allows the distribution company flexibility in managing the hours of supply for agriculture without affecting supply hours for other consumers.

Feed-in-Tariff (FiT)	It is a state and technology specific preferential tariff set by state regulatory commission. It is essentially a generic regulated cost plus tariff, which ensures a 16 percent return on equity.
Forum of Regulators (FoR)	It is a statutory body under the Electricity Act, 2003 to ensure smooth and coordinated functioning of the power sector and consists of chairpersons of central and state regulatory commissions.
Generation Based Incentive (GBI)	It is an electricity production linked incentive for wind Independent Power Producers given out by the Ministry of New and Renewable Energy over and above the state feed-in-tariff. It was launched in 2009 and was set at ₹ 0.5/kWh.
Glacial Lake Outburst Flood (GLOF)	Glacial lakes are formed when glacial ice or moraines or natural depressions impound water. The moraine creates topographic depression in which the melt water is generally accumulated leading to formation of glacial lake. Failure of these ice or moraine dams leading to disastrous destruction events has been documented throughout the world. Such flash floods caused by the outburst of glacial lakes are called as Glacial Lake Outburst Flood (GLOF). GLOFs have immense potential of flooding in downstream areas, causing disastrous consequences due to release of large volumes of water in very short interval of time.
Grid parity	It can refer to consumer grid parity or generation grid parity. Consumer grid parity (socket parity) occurs when an alternative energy source (generally some RE source) can generate power at the consumer electricity tariff from the central grid. Generation grid parity occurs when alternative energy sources can generate utility scale power at a cost that is less than or equal to the cost of generation from new conventional technologies such as coal/gas etc.
High Tension (HT) consumers	It refers to electricity consumers connected to high tension network having voltage level of 11kV and above.
Hydrocarbons	It refers to organic compounds comprising only of hydrogen and carbon. In the energy sector, this refers to oil and gas resources.
Indian Electricity Grid Code (IEGC)	It refers to a set of technical and commercial rules, encompassing all the Utilities connected to/or using the Inter State transmission system (ISTS) to ensure among other things, the optimal operation of the grid. It defines a common basis for operation of the ISTS and is applicable to all the users of the ISTS.

Levelised tariff	It is a concept used in thermal power sector to compare project costs. It is an indicative tariff which, if paid over the entire duration of the PPA, would match the value of tariff that is quoted for each month or year, over the term of the contract. Thus, for the buyer, it represents the net present value of payments (monthly, yearly or per unit) to be made over the contract duration and hence makes it possible to compare tariff quoted by different projects for the same duration. In the renewable energy context, levelised tariff is the tariff set by the regulator or discovered through competitive bidding. Unlike thermal power this is the actual tariff paid to the developer over the entire life of the PPA.
Linkage	It is an arrangement to supply coal from a nationalised coal company (e.g.: Coal India Ltd.) to an identified end-user. Until recently, the Standing Linkage Committee (Long Term) allocated linkages for all sectors. Recently, a mechanism has been introduced to allow auctioning of linkages for certain category of end-use sectors.
Low Tension (LT) consumers	It refers to electricity consumers connected to the low tension network having voltage level below 11 kV.
Merit order	It is a sequence in which generators are chosen for dispatch. Merit order is prepared based on variable cost of generation. Stations with lowest variable cost of scheduled first. Renewable energy plants are generally not subject to merit order since they have a must-run status.
Multi Year Tariff (MYT)	It is a framework for tariff determination by regulatory commissions spanning multiple years (3-5 years). The objective is to enable longer term planning to provide certainty of revenue and costs to both, electricity companies and consumers.
Net metering	It is a billing mechanism usually adopted for rooftop solar PV systems which allows energy banking and credit for excess solar electricity fed into the distribution grid by the project. At the end of the billing period, the consumer only has to pay for the 'net' electricity consumed (difference between electricity consumed from the grid and electricity fed into the grid from the solar project). If the amount of electricity fed into the grid is more than that consumed from the grid, the excess is carried forward to the next billing period.
Ombudsman	It is an appellate body for settling consumer grievances in the electricity sector. Ombudsman is appointed by the state regulatory commission. Any consumer aggrieved by an order of the consumer grievance redressal forum can appeal against it before the Ombudsman.

Open Access (OA)	It is a mechanism which allows large consumers to purchase power from their choice of generator, trader or power exchange while being connected to the network of the distribution company. The Electricity Act, 2003 mandates non-discriminatory access to the distribution and transmission network for any consumer desiring open access.
Open Acreage Licensing	A mechanism wherein a prospective licensee can proactively express interest to develop an oil and gas exploration block without waiting for a formal bid round from the government. Once the expression of interest is received, the government opens the block up for bidding after undertaking prudence checks to ensure that the interest is justified.
Peak Load	It refers to the highest electricity demand (load) during a day. Peak load is usually met through flexible generation sources such as natural gas and hydropower.
Pooled Power Purchase Cost	In the context of Renewable Energy Certificate mechanism, Pooled Cost of Purchase is the weighted average pooled price at which the distribution licensee has purchased the electricity including cost of self-generation, if any, in the previous year from all the energy suppliers, long-term and short-term, but excluding those based on renewable energy sources.
Production Sharing Contract	A type of contract typically employed in oil and gas exploration and production, wherein the entity granting the contract, typically a government, receives a share of the production realised by the contractor. This share can be based on total revenue or profits or some combination thereof. In Indian oil and gas sector, a production sharing contract usually refers to aprofit sharing mechanism where the central government receives a share of the profit realised by the contractor after recovering exploration, development and production costs.
Profit petroleum	In the context of oil and gas exploration and production contracts, profit petroleum is the total annual revenues from sale of oil and/ or gas minus approved exploration and production costs.
Reasoned order	It refers to orders issues by electricity regulatory commissions which document objections and suggestions of all parties and which provides reasons for the decisions taken in the order.
Regulations	It refers to rules made by the regulatory commissions as per their mandate under the Electricity Act, 2003.

Renewable Energy Certificate (REC)	It is a national regulatory instrument initiated by the central commission which allows for separating the green environmental attribute (represented by the REC certificate) of the renewable electricity and traded separately. Its objective is to overcome the mismatch between renewable energy resource availability and renewable purchase obligation compliance and also promote additional investments and to set up alternative cost recovery business models.
Renewable energy sources	It refers to resources representing energy flows, which are naturally replenished at a rate that equals or exceeds its rate of use and includes low-carbon technologies such as solar, wind, hydropower, tidal, wave and ocean thermal energy, as well as renewable fuels such as biomass. India only counts Small Hydro Power (SHP) < 25 MW as part of renewable energy; conventional large hydropower (> 25 MW) is not part of the official definition of renewable energy in India.
Renewable Purchase Obligation (RPO)	It is a target set by state regulatory commissions, which mandates distribution companies and other obligated entities like open access and captive consumers to procure a minimum fraction of their overall electricity consumption through renewable energy sources.
Revenue Sharing Contract	A type of contract typically employed in oil and gas exploration and production, wherein the entity granting the contract, typically a government, receives a share of the revenue realised by the contractor. Revenue sharing contracts are easier to administer than profit sharing contracts since prudence of costs undertaken by the contractor need not be verified.
Secondary energy	It is the quantum of energy generated in excess of the design energy on an annual basis at a hydropower station.
Standard bidding guidelines	These are guidelines issued by the Ministry of Power which lay down a framework and process for procurement of power through competitive bidding. Any power procurement by distribution companies under section 63 of the Electricity Act, 2003 needs to be in accordance with these guidelines.
Standards of Performance (SoP)	It is a set of performance parameters notified by the state regulatory commission to ensure a certain standard of electricity service. It includes standards for parameters such as deviations in voltage, time taken to attend complaints, restoration of supply after fault etc. It also specifies compensation in case of failure to comply with these standards.

Standby charges	It is a charge to be paid by an open access or captive consumer for procuring standby power in case its identified generator fails to supply. Generally the standby power is supplied by the distribution company. Standby charges are generally very high.
Steam coal or non-coking coal	This refers to lower calorific value coal used in industries such as power, cement, etc.
Transmission & Distribution (T&D) loss	It refers to the electricity losses in the transmission and distribution network.
Transfer scheme	As per the Electricity Act, 2003 the state electricity boards were to be unbundled into separate companies for distribution, transmission and generation. For this purpose, the state government was to launch a transfer scheme to settle claims and outstanding liabilities of the erstwhile electricity board and transfer assets and personnel to the newly formed companies.
True-up	It is an accounting term in the power sector which refers to adjustment of costs and revenue of regulated electricity companies based on past performance and actual audited accounts for that period.
Unscheduled Interchange (UI)	In the context of a generator or a trader it refers to the total actual generation minus its total scheduled generation for a given time block. For a buyer, it is the total actual drawal minus its total scheduled drawal.
Upstream	It generally refers to energy supply activities related to energy resource exploration and extraction. Typically used in the oil and gas sector, upstream refers to the exploration and production phase, where surveys are conducted to estimate oil and gas reserves, and wells are drilled to ascertain reserves and to extract crude oil or raw gas to the earth's surface.
Wheeling charges	It is a charge to be paid by open access/captive consumers to the respective distribution licensee for use of its distribution network.

Parameters	Thermal (coal & gas)	Large hydropower	Renewables	Distribution	Coal	Natural gas
Ownership and Industry structure	• Upto 1990: Mostly Government owned • 1992: opened for private sector and 100% foreign investment, but share of private sector continued to be very small till 2000 • 2003: setting up thermal capacity de-licensed under Electricity Act 2003 • 2016: 38% of thermal capacity is privately owned • More than half of the capacity added in the last decade is by private sector	• Up to 1990: Mostly Government owned • 1992: opened for private sector and 100% foreign investment, but share of private sector continues to be small • Apparent increase in pace of creation of privately owned capacity in late 2000s, but faltering once again • March 2016: 7.3% capacity is privately owned • Several private projects taken over by public sector	• Early 90's to 2012: Virtually entirely based on private sector investments, with exception of older small hydropower projects, most of which are state owned • 2012-2016: Small but steadily rising investments and ownership from some PSUs like NTPC, SECI, Railways, OMCs etc. • Solar sector has structurally ingrained competition with high number of players, while wind sector is still large vertically integrated with lesser competition. IPPs growing in wind sector	• Up to 1996: Integrated SEBs in all States. Private distribution in Mumbai, Kolkata, Ahmedabad and Surat • Distribution privatisation in Odisha (1999) and Delhi (2002) • 2016: Most SEBs unbundled into state owned companies, private franchisees in few urban areas, Odisha distribution back with state government • Transmission largely publicly owned, but slow growth of joint ventures and private companies	• Up to 1973: Mostly private sector • From 1973: Government owned after Coal Mines (Nationalisation) Act passed in 1973 • Coal India Ltd. (7 mining subsidiaries, 1 subsidiary focused on exploration) now produces ~80% of India's domestic coal	• Pre-independence: Mostly private sector • 1950s up to 1999: Predominantly public sector • Since 1999: Increasing role for private sector in exploration, production and refining • Since 2007: Increasing role for private sector in transportation and distribution of gas
Institutional structure	• Tariff: can either be discovered through bidding or determined on cost-plus basis by the regulatory commission • Performance regulated by Central or State Electricity Regulatory Commission (SERC) • Any disputes between a generator and buyer to be resolved by the respective regulatory commission, appeals can be filed before the Appellate Tribunal for Electricity (ATE)	• Tariff: regulated on cost-plus basis by the regulatory commission, subject to certain conditions like international competitive bidding for equipment and construction • Little competition or market based operation in the sector • Project developer fully protected from hydrological risk for ten years, beyond which there is still significant protection from hydrological risk • CEA concurrence needed for projects with more than the notified outlay • CDM benefits for several hydropower projects provided significant revenue bonus	• Policy making by MNRE and state govts, with increasing role of MoP in last few years • Mandatory minimum Renewable Purchase Obligations (RPOs) for obligated entities set by SERCs • Preferential tariffs/feed-in-tariffs set by SERCs separately for each RE technology for each year (cost plus tariff). However solar has moved on to competitively discovered tariffs while wind continues with FiTs. MNRE initiating competitive bidding for wind power projects starting with 1 GW in 2016-17 • Any disputes between a generator and buyer to be resolved by the respective regulatory commission, appeals can be filed before the Appellate Tribunal for Electricity	• Ministry of Power and Central Electricity Authority prepares national policies and plans • Many large scale central sector programmes for loss reduction, access and financial support, monitored by the GoI and implemented by DISCOMs • National, regional and state load dispatch centres to coordinate grid operation • Multi-state generation, transmission and markets regulated by Central Electricity Regulatory Commission • DISCOM tariff and performance regulated by SERC, appeals can be filed before the ATE • Three tier institutional mechanism to address consumer grievances – DISCOM grievance forum, Consumer Grievance Redressal Forum and Ombudsman • State DISCOMs managed by the energy ministry	• Governed by Ministry of Coal, assisted by Coal Controllers' Organization (part of MoC) • Nothing equivalent to a quasi-judicial independent regulator in the sector	• Governed by Ministry of Petroleum and Natural Gas • Director General of Hydrocarbons (DGH) is the government regulator for the exploration and production (E&P) activities • Petroleum and Natural Gas Regulatory Board (PNGRB) is the independent regulator dealing with gas transportation and distribution
Reform milestones	• 1992: Independent Power Producers (IPP) policy. MoU based project selection • 1995: Mega power policy, which provided many incentives and tax holidays for large size plants (>1000 MW). The policy is still in force, though terms have been modified from time to time • 2003: Electricity Act and introduction of competitive bidding for capacity addition based on transparent process • 2005-06: Ultra Mega Power projects (UMPP) policy, special case of competitive bidding for large size (4000 MW or more) projects for which central/state government would provide the site (land), fuel, water, environment and forests clearance and ensure substantial progress on land acquisition through a shell company	• 1992: Independent Power Producers (IPP) policy. Directly negotiated MoUs and PPAs • 1995: Tariff notification, enshrining several incentives, protection from risks • 1998: Notification removes limit on amount that private projects could raise from Indian public financial sources • 1998: New hydropower policy notes public sector would continue to play a dominant role for some time and reiterates the need to increase private investment. Measures to encourage both public and private developers. Recommendations include premium pricing for peaking power, expert committee to sanction cost escalation due to geological problems, insulate project from problems of R&R and land acquisition • 2003: The 50,000 MW initiative to install as much capacity by 2017 launched by then PM Vajpayee • 2008: New hydropower policy brought out, with explicit focus to promote private investment in hydro	• 1992: Opening up to private sector with 100% FDI allowed • 1993: MNES advisory to states to price RE at min of ₹ 2.25/kWh with 5% annual esc. for 10 yrs. Incentives of accelerated depreciation and energy banking • 2003: Electricity Act, 2003 brought in RE targets (RPOs) • 2006: Tariff and Electricity policy institutionalised cost plus preferential/feed-in tariffs • 2008: Launch of National Solar Mission as part of NAPCC and subsequent move to competitive solar price discovery • 2010: Launch of Renewable Energy Certificate mechanism to overcome geographical mismatch of resources • 2010: Regulatory initiatives to mandate forecasting and scheduling of wind and solar power started, but only begun to be operationalized in 2016 • 2009: Generation Based Incentive for wind power • 2012: National Clean Energy Fund through cess on coal • 2016: Tariff policy amended, recommends 8% solar RPO by 2022	• 1996: Unbundling starts in Odisha, with World Bank support • 1996-2016: Distribution privatisation and introduction of franchisees • 1998: Electricity Regulatory Commissions Act • 2001: Energy conservation Act and institutionalising Bureau of Energy Efficiency (2002) • 2003: Electricity Act and national policies, introduction of electricity traders and open access • 2005: National rural electrification program – RGGVY • 2008: Introduction of power exchanges • 2015: National programs on energy efficiency, proposals to amend Electricity Act 2003	• 1973: Nationalization of coal mining • 1993-2010: Captive blocks allocation round one • 2000: Price decontrol – coal mining PSUs free to set their own prices • 2007: New Coal Distribution Policy • 2015: New legislation enabling commercial mining by private sector • 2015-16: Captive block allocations round two • 2016: Mines alloted for commercial mining by state PSUs	• 1955: Formation of Oil and Natural Gas Directorate (later renamed ONGC) • 1981: Nationalisation of OIL • 1991-1995: Private sector participation in E&P through pre-NELP production sharing contract (PSC) auctions • 1999-2012: Private players compete on equal terms with public sector companies in E&P through NELP PSC auctions where profit is shared between contractors and government • 2007: Petroleum and Natural Gas Regulatory Board set up to regulate cross-country pipeline and city-wide distribution networks • 2014: New gas pricing policy announced
Major controversies	• IPP policy: Ad-hoc and non-transparent selection process for signing MoUs, secrecy in negotiating tariffs. Most projects for which MoUs were signed never materialised • Competitive bidding: Encouraging start, tariff discovered seemed economical. More than 40 GW of capacity added. Uncertainty due to post facto revision of discovered tariff, governance issues in various bidding rounds • UMPP: Only 4 out of 10 identified sites awarded till 2016. 3 out of these 4 UMPP contracts won by a single company. 2 out of these 4, namely Tilaiya and Krishnapattanam have been abandoned. Only 2 UMPPs (Sasan & Mundra) are generating power but seeking revision of quoted tariff	• IPP policy: Ad-hoc and non-transparent selection process for signing MoUs, secrecy in negotiating tariffs • Allocation of sites in Himalayan states through high upfront payments making projects fait accompli and vitiating environmental & forest clearances processes • Maheshwar project, representing many of the ills of the reforms. Handed over to private developer in early 1990s, non-transparent process, capital cost shoots up on privatisation, PPA skewed to benefit developer, indicates very high tariffs, failed R&R, opposition from affected communities. In 2016, project still incomplete, CEA puts cost at 6800 crores for this 400 MW project. Most of the 2300 crores spent till date is from public financial sources	• Allegation in the early years, that wind projects came up mainly for fiscal benefits with little focus on siting and generation performance • Adverse impacts on the local natural environment and irregularities in land transactions and compensation in some projects • Failure of SERCs to penalise obligated entities for RPO non-compliance in line with their own regulations	• Repeated financial bail-outs for state owned DISCOMs • Failed Odisha privatisation: Exit of AES (2001), revoking license of other 3 companies (2015) • Bidding and implementation issues, leading to termination of some urban franchisee agreements • States preparing over ambitious capacity addition plans, power surplus reported in many states in 2016 and DISCOMs paying for stranded generation capacity – all due to faulty power purchase planning • Agriculture consumption is largely not metered, leading to high consumption estimate, large subsidy demand and low T&D loss claim by the DISCOMs	• Captive blocks allocation I: Ad-hoc, discretionary, and some illegalities • Linkage allocation: Ad-hoc, unrealistic, ambiguous • Captive blocks allocation II: Legal and regulatory complexity, potential unviability of bids	• NELP: Contract related issues in administration of the PSC regime, e.g., cost recovery, contract area relinquishment, gas pricing and reservoir management. Governance issues and weak regulatory capacity • PNGRB: Bad legislation leading to weakened regulator, legal controversies and uncertainty
Areas neglected	• Demand estimation: No scientific demand forecast. Capacity addition based on gross estimates • Social and environmental issues concerning thermal projects • Proper recording and monitoring of plant performance • Fuel allocation policy: Ad-hoc and ambiguous leading to disputes, price escalation and legal issues • Regulatory governance issues concerning bidding process, sanctity of contracts and capacity addition	• Social and environmental issues of hydropower projects, particularly land acquisition, resettlement and rehabilitation • Cumulative impact assessments and river conservation • Impacts of climate change • Assessing extent to which projects will actually deliver peaking power, creating appropriate framework to incentivise peaking power	• Strict RPO compliance • Bringing in competition in the wind sector • Integrating variable renewables like wind and solar in grid operation protocols (forecasting, scheduling, and commercial settlement of deviation) • Fully operationalizing and facilitating net metering for rooftop solar • Local environmental and land procurement aspects • Integration of RE within overall electricity sector planning, operation	• Monitoring supply quality • Household electrification • Agriculture supply • Regular tariff determination and performance evaluation • Electrical safety • Reliable affordable power supply to small consumers • Energy efficiency	• Resource estimation • Coal market structure and efficiency • Law and order issues • Comprehensive approach factoring in consuming sectors	• Gas pricing: Inadequate attention to policies guiding arm's length pricing of gas in the absence of a national gas market • Transparency in E&P operations: contractual milestones vis-à-vis achievements, development plans etc. not available in public domain
Key challenges	• Proper demand estimation in the face of dwindling consumer base of distribution companies • Financial viability of distribution companies, which continue to be the key buyers • Shaky future in light of reducing costs of renewables and storage (in the long run) • Fuel sector policy and governance – availability, affordability and quality continues to be a concern • Controlling and mitigating social and environmental impacts • Non base load (cycling) operation due to increase in renewables and excess capacity • Implementation of new stricter environmental norms for coal plants	• Handling social and environmental issues • Uncertain financial viability and future of hydropower projects uncertain without significant support and incentives • Balancing hydropower development, particularly in cascades of multiple projects in a basin, with the stated objectives of river conservation and rejuvenation, defined as including *aviral dhara* and protection of ecological integrity of rivers • Lack of basin wide carrying capacity studies and cumulative EIA studies	• Weak data management • Evolving national and state transmission planning practices which are sensitive to renewables and having uniform inter-connection practices across states • Reliable grid integration with minimal additional costs • High interest rates affecting cost of RE power • Incentivising growth of RE (enforcing RPOs, net metering, concessional RE based open access) without severe strain on DISCOM finances • Continuation of separate solar and non-solar RPO and REC categories when solar prices going below wind • Differing priorities and capabilities of the Centre and state on some issues	• Universal access to households and small consumers • Financial health of DISCOMs • Professional management of DISCOMs • Weak capacity of Regulatory Commissions • Managing growth of markets and renewables • Appropriate power purchase planning • Designing equitable and viable tariff structures • Metering, energy audits and loss estimation • Public oversight of transmission sector	• Lack of open, transparent and participative governance structure • Market concentration • Lack of independent regulation • Socio-environmental impacts handled poorly • Weak demand and dwindling interest	• Weak regulatory capacity, independence and effectiveness • Poor and difficult to access domestic gas reserves • Need for a licensing and pricing regime that strikes a balance between investor interest, government revenue and availability and affordability of natural gas
Upcoming initiatives	• New bidding guidelines to make fuel costs completely pass through • Subsidy schemes to generate power from stranded gas based capacity	• New hydropower policy and incentives framework in the offing, appears to be "more of the same"	• Dedicated Renewable Energy Law, significant amendments in Electricity Act, 2003 to boost growth of RE • Offshore wind, wind and solar hybrids, repowering of old wind sites • State level forecasting and scheduling and deviation settlement regulations for RE • Competitive bidding for wind	• Increasing role of market and renewables and consequent sales migration • Scheme to bring about financial turnaround of DISCOMs – UDAY • Possible entry of multiple suppliers in DISCOM area • 24 x 7 power for all • Feeder separation in all states • Large investments in transmission – by govt and private companies • National level programmes for appliance efficiency	• Ambitious plans to ramp up production • Auctioning linkages • Potentially more players involved in commercial mining	• Revenue sharing contracts and open acreage licensing announced for E&P • Marketing and pricing freedom for gas produced from difficult to access areas and marginal fields

Prayas (Energy Group)

Many Sparks but Little Light,
January, 2017

The electricity sector and allied fuel sectors in India have been subject to various waves of reforms from the early 1990s. This book critically examines many of these reforms and the impacts they have had, to understand if they achieved their expected objectives and if they helped in achieving the desirable socio-environmental outcomes. The in-depth analysis covers thermal, hydropower and renewable generation, electricity distribution, and associated fuel sectors of coal and natural gas.

The book concludes that while the sector has made some significant strides, the reforms have generally disappointed. The stated objectives of reforms have not been fully met and India is far from meeting its socio-environmental objectives in electricity. The sector is also plagued by insufficient competition, weak institutions, and poor design and implementation of policies and laws. The book argues that the usual polarised debate of 'for and against privatisation' is misleading. It proposes that discussions should instead be centred on how to have robust governance and institutions – within and outside government – that can achieve desirable socio-environmental goals in a transparent and accountable manner. This is essential if future reforms are to deliver better results.

Prayas (Energy Group)