

The Experience of Independent Power Producers in Developing Countries

Erik J. Woodhouse

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The Program on Energy and Sustainable Development at Stanford University is an interdisciplinary research program focused on the economic and environmental consequences of global energy consumption. Its studies examine the development of global natural gas markets, reform of electric power markets, international climate policy, and how the availability of modern energy services, such as electricity, can affect the process of economic growth in the world's poorest regions.

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Program on Energy and Sustainable Development

At the Center for Environmental Science and Policy

Encina Hall East, Room 415

Stanford University

Stanford, CA 94305-6055

<http://pesd.stanford.edu>

About The Experience of Independent Power Projects in Developing Countries Study

Private investment in electricity generation (so called "independent power producers" or IPPs) in developing countries grew dramatically during the 1990s, only to decline equally dramatically in the wake of the Asian financial crisis and other troubles in the late 1990s. The Program on Energy and Sustainable Development at Stanford University is undertaking a detailed review of the IPP experience in developing countries. The study has sought to identify the principal factors that explain the wide variation in outcomes for IPP investors and hosts. It also aims to identify lessons for the next wave in private investment in electricity generation.

PESD's work has focused directly on the experiences with IPPs in ten developing and reforming countries (Argentina, Brazil, China, India, Malaysia, Mexico, the Philippines, Poland, Thailand and Turkey). PESD has also helped to develop a complementary study at the Management Program in Infrastructure Reform & Regulation at the University of Cape Town ("IIRR"), which is employing the same methodology in a detailed study of IPPs in three African countries (Egypt, Kenya and Tanzania).

About the Author

Erik Woodhouse is a Postdoctoral Fellow with the Program on Energy and Sustainable Development. His current research focuses on energy infrastructure investment in developing countries. Other recent research includes work in comparative corporate governance and law in international relations.

Mr. Woodhouse holds a J.D. from Stanford Law School and a B.A. from Emory University in International Studies and Philosophy.

Disclaimer

This paper was written by a researcher (or researchers) who participated in the PESD study *The Experience of Independent Power Investment in Developing Countries*. Where feasible, this paper has been reviewed prior to release. However, the research and the views expressed within are those of the individual researcher(s), and do not necessarily represent the views of Stanford University.

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I. INTRODUCTION.

In the 1990s a rising tide of private investment in power infrastructure flooded into developing countries, much of it focused on power generators known as “independent power projects” (IPPs). The absolute level of investment peaked in 1996 and then ebbed rapidly by the end of the decade.

This draft reports on progress in a study to examine the IPP experience in thirteen countries—Argentina, Brazil, China, Egypt, India, Kenya, Malaysia, Mexico, the Philippines, Poland, Tanzania, Thailand and Turkey. At this writing, research is nearly complete in ten of those countries; in Argentina, Brazil and Tanzania work remains under way. The research team has drawn on detailed interviews and discussion with participants from industry, government, multilateral institutions, NGOs, and sundry other experts and stakeholders.

Part II of this paper provides an overview of the IPP market during its rise and decline in the 1990s, as well as a look to where the market is headed. Part III discusses the critical theoretical concepts and definitions that analysts have deployed in evaluating infrastructure investment. Having presented a factual and theoretical framework, the paper then presents a systematic analysis of the factors that explain outcomes in IPP investment.

The study pursues two objectives. First, we explain variation in country performance—namely why some countries have provided hospitable environments for investors, and have benefited from sustainable investment in power generation, while others have proven to be much more difficult environments. Second, we explain variation in project performance—why investors and hosts alike are happy with some projects while others, even in the same country, have created bitter disappointment for key stakeholders. Parts IV and V address these two questions in turn.

While the full story is complicated, and the work presented here still tentative, we suggest five major conclusions about the IPP experience. First, there is wide variation in the outcomes of IPP projects. We have distinguished between outcomes for investors and for host countries and found some cases where the two are not correlated. Moreover, the conventional perception that IPP investments have generally failed to meet expectations is incorrect; indeed, there are many projects that are viewed as a success by investors and hosts alike.

Second, the presence of macroeconomic shocks explains a substantial part of the range of observed outcomes—where shocks are prevalent, projects generally fare less well than when the macroeconomic context is stable. However, the extent to which shocks affect projects depends critically on the mechanisms that governments put into place to manage the adjustments that are required in the aftermath of these shocks.

Third, a few countries—notably Thailand, Mexico, and Egypt—have emerged as “best practices” for the IPP model. These countries have all managed to extract the maximum value from the classic IPP mode of investment. All three

include strong government support for the state utilities that purchase the power from IPPs; all have implemented relatively few reforms in the electric sector and have signaled to investors that other regulatory changes are unlikely. These cases indicate, however, the limitations of the traditional IPP model: payment guarantees are increasingly not credible as the liabilities from these schemes mount, and IPPs may frustrate the broader reforms that are essential to producing solvency and economic efficiency in the sector.

Fourth, IPP investors face enormous (but not insurmountable) difficulties when the perceived costs of their projects are much higher than those in the surrounding market. These perceptions lead to an erosion of confidence in the IPP model and, for individual projects, usually force a change in contracted payments. In practice, it is extremely difficult to make an objective determination of whether a project's costs are fair. Private generators operating in state-dominated power markets have completely different cost structures when compared with other generators in the country's experience. Because comparison is not an easy objective task, IPPs generally remain vulnerable to these criticisms.

Fifth, IPPs are like other capital-intensive infrastructure investments in their vulnerability to opportunistic government action. In the 1990s wave of IPPs, investors loaded these risks into contracts and relied on a handful of common methods to bolster these contracts' enforceability. Those methods, including recourse to international arbitration and enlisting well-connected partners, have delivered very mixed results. Arbitration has not provided the security sought by investors. Partnering strategies, while often necessary, have rarely been sufficient to insulate project stakeholders from pressure. In general, creditors have fared according to expectations, but equity investors have often seen their returns squeezed.

Sixth, despite these troubles in making contracts strictly enforceable, in practice contracts have had more traction than is commonly acknowledged. Pessimism about the role of contracts has been driven by unrealistic expectations that detailed contracts would fully solve the fundamental challenges of investments that, by nature, occur in a highly complex and changing economic and political environment. Outright repudiation of contracts is rare, but pressure on contract terms is commonplace. In general, government pressures on contracts focuses where there are opportunities for adjustment; government and investor alike attempt to negotiate and adjust contracts in an environment of highly imperfect information that is laden with suspicion and opportunism. In the face of these challenges, some countries have had notable success with mechanisms that yield stability by creating transparency in costs and benefits of IPP investments.

Mindful of these conclusions, which we will weave through Parts IV and V, Part VI shifts focus explicitly from reviewing the past to addressing the challenges of the future. Finally, Part VII concludes the paper.

II. OVERVIEW OF THE IPP EXPERIENCE, 1984-2004.

A. The Country Context for IPP Investment.

The world's electric power systems are in the midst of a dramatic institutional transformation. During the 20th century, across most of the world, the electric power system became organized through integrated state-owned enterprises (SOEs). That model has faltered for various reasons, and we will focus on the experience in the developing and reforming countries. In many countries, electricity became highly politicized and tariffs were set so low that the power enterprise could not cover its costs. Like most state enterprises, nearly every electricity SOE became encumbered by excess staff; the vast majority were also plagued by the inefficiencies that arise when key managers are selected for their political connections rather than business acumen.

Over the last fifteen years essentially every major developing and reforming country has undertaken some reform of its electric power system. Often, those reforms were ushered in during the political opportunities that arise in the midst of a financial crisis—themselves partly triggered by the mounting costs to the public sector of improperly priced electricity and poor management. These reforms have generally sought to introduce market forces to the power sector. Such efforts have been guided, in part, by the early experiences in Chile and in England & Wales—successful market reforms that helped to write a “textbook” for power sector reform that envisioned the unbundling of SOEs into separate generation, transmission, distribution and marketing companies, followed by privatization. This standard textbook model also envisioned that generation and marketing would be exposed to competition while independent professional regulators would oversee the natural monopolies of transmission and distribution.

In practice, most developing countries have found it difficult to implement the strictures of the standard textbook model. (Many in the industrialized world have also stumbled—spectacularly so in California.) Earlier research at Stanford has shown that these difficulties in implementation arise in several quarters. Notably, power sector reform depends on a series of interlocking changes elsewhere in government that are essential to imposing market discipline on the power sector. For example, state budget reforms have been essential to imposing hard budget constraints on SOEs; the imposition of independent corporate governance has been essential to creating truly competitive and accountable new private enterprises; legal reforms have been essential to giving regulators the standing to issue credible orders.

The myriad difficulties in reform and the fact that SOEs have been important sources of political patronage have led to an unanticipated outcome. Rather than the complete dismantling of the old SOEs and the emergence of independent competitive companies, most reform efforts have yielded a hybrid: firms that are laden with the political assets typical of SOEs and necessary to operate in a politicized power market and yet also exposed to some market forces that put a premium on good management that is more typical of private ownership and competition. We have called these “dual firms,” and in our earlier work we have shown that these firms resist a return to the old integrated state system, but they also resist further imposition of reforms that could erode the

firms' privileged position.¹ Power reform gets stuck in a halfway house between state ownership and private control.

In the face of immense difficulties in implementing complete reform of the power sector, governments in developing countries nonetheless have been forced to address an urgent problem. In many countries, the lights were literally flickering; new investment would be needed on a much faster timetable than the slow and politically painful process required for a complete overhaul of the power sector. In most countries, the politically expedient solution followed a path of least resistance. Driven by investment crises, reformers focused on meeting immediate needs, and politicians carved out a specific legal space for private investment in the form of private power plants.

These new independent power producers (IPPs) would sell bulk electricity into the state-dominated power system under a long term power purchase agreement (PPA). Such projects promised lower costs and offered the prospect of limited competition (or at least a competitive benchmark) in the sector. By tapping private capital, governments would no longer need to raise the financing for new capacity themselves, which was particularly attractive to governments that were attempting to manage financial crises and cash-poor state finances.

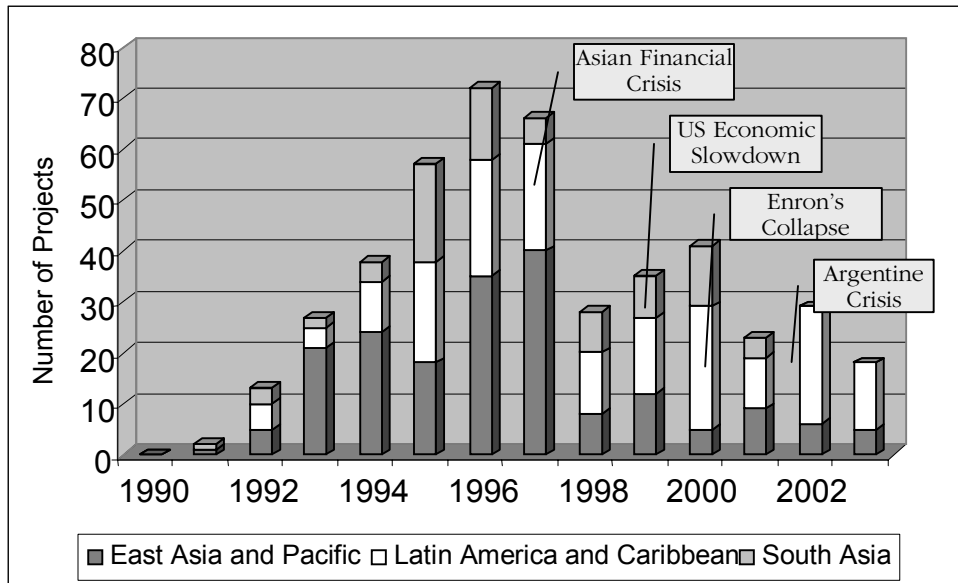
B. The Rise and Fall of IPP Investment.

Private investment in greenfield power generation projects in developing countries was a booming market for private investors in the 1990s. The total value of deals closed in 1996 alone was almost \$17 billion.²

FIGURE 1: PRIVATE INVESTMENT IN POWER GENERATION IN DEVELOPING COUNTRIES

¹ DAVID G. VICTOR AND THOMAS C. HELLER EDS., POLITICAL ECONOMY OF POWER SECTOR REFORM: THE EXPERIENCE OF FIVE MAJOR DEVELOPING COUNTRIES (Cambridge University Press)(forthcoming, 2005).

² Data drawn from the World Bank's Private Participation in Infrastructure Database, available at <http://ppi.worldbank.org> [hereinafter "World Bank PPI Database"].



Source: World Bank Private Participation in Infrastructure Database, available at <http://ppi.worldbank.org> (visited April 14, 2005).

The growth of this market was fueled by three interacting trends. The first was increasing demand, discussed above, from developing countries in response to electricity or financial crises. Second, key changes in lending policies from major multilateral banks shaped government's emphasis on private investment by restricting access to concessionary loans without complementary moves to reform and privatize infrastructure. From 1990 until 1996, the World Bank Group had a "no-lend" policy (officially promulgated in a 1993 paper) for the power sector unless accompanied by substantial reforms.³ Third, massive liquidity and tight domestic returns in US and European utilities markets drove investors to seek higher returns in new markets abroad. Prominent on this list were Electricite de France, Iberdrola, AES, Enron, Duke Energy, Edison Mission Energy, CMS Energy, Southern/Mirant, International Power plc, Powergen, and Suez/Trachtebel.

However, by 1999, this market had collapsed in both quantitative and qualitative terms. Private investment in IPPs sank to \$6 billion dollars in 2001.⁴ China, India and Argentina—countries, among many others, that had been prized attractions—saw investors flee in droves. Spectacular controversies such as the Dabhol project in India, the Hub project in Pakistan, and the entire IPP sector in Indonesia, dominated the industry headlines.

The early stages of this decline in IPP investment coincided with a rash of corporate scandal in the United States (including the downfall of Enron, a major IPP investor)⁵, the bursting of the dot-com bubble and domestic recession in the

³ World Bank, *Private Sector Development in the Electric Power Sector: A Joint OED/OEG/OEU Review of the World Bank Group's Assistance in the 1990s*, Report No. 26427 (2003), at 2.

⁴ *Id.*

⁵ See, e.g., Henry A. Davis, *How Enron has affected project finance*, 8 J. STRUCT. & PROJ. FIN. 19 (2002) (discussing the collapse in infrastructure project financing in the context of the major

United States, and somewhat later, the attacks of September 11th and an increasingly uncertain global security environment. All of these exogenous factors have affected the market for foreign direct investment in infrastructure; yet it has proven difficult to disentangle the relative significance of these exogenous factors from factors that are internal to the power sector. Many of the most prominent players in the IPP market have left—driven by losses in their home markets (El Paso, Mirant, Duke, CMS), or strategic decisions to refocus investment on industrialized markets (Bechtel/Shell, Powergen).

Today, the market is increasingly populated by multinational firms for whom foreign power investment is their core business (AES, Globeleq) and by domestic and regional actors who are perceived as more adept at managing the risks involved in developing country infrastructure investment (China Light & Power, Reliance, Malakoff, Mitsui). Additionally, state controlled firms spun-off from national utilities are assuming a more prominent role (ECGO, Huaneng Power Group, NTPC) while increasingly tapping international capital markets.

III. KEY CONCEPTS AND DEFINITIONS.

Despite its prominence in the pantheon of infrastructure investment, the collapse in the IPP market and its implications for future investment remain poorly understood. The existing literature on IPP investment suffers from one central deficiency: the lack of systematic attention to the factors that explain cause and effect. Much of the publicly available analysis has focused on a few projects, such as India's Dabhol, and proffered a range of anecdotal and tailored hypotheses for why particular projects fail. Indeed, the pathologist's attraction to grim failure has obscured the full scope of the IPP experience. Failures are usually more visible and easier to dissect with publicly available information than are the myriad of projects with different outcomes—many of them quite beneficial for investors and hosts alike.

Overall, more than forty countries have had experience with IPPs, and the total number of individual projects is in the hundreds.⁶ The relative success and failure of projects within this global sample is not known with precision—the vast majority of IPPs are financed privately, meaning that information providing a meaningful measure of success is difficult (and often impossible) for detached scholarly observers to obtain. Some projects have been cancelled, most have been renegotiated, and there has been significant equity turnover; yet most are also still generating electricity.

With these difficulties in mind, this section identifies key concepts that frame our exploration of the IPP experience, key questions to be addressed, and a methodology for generating focused results.

A. The Model IPP.

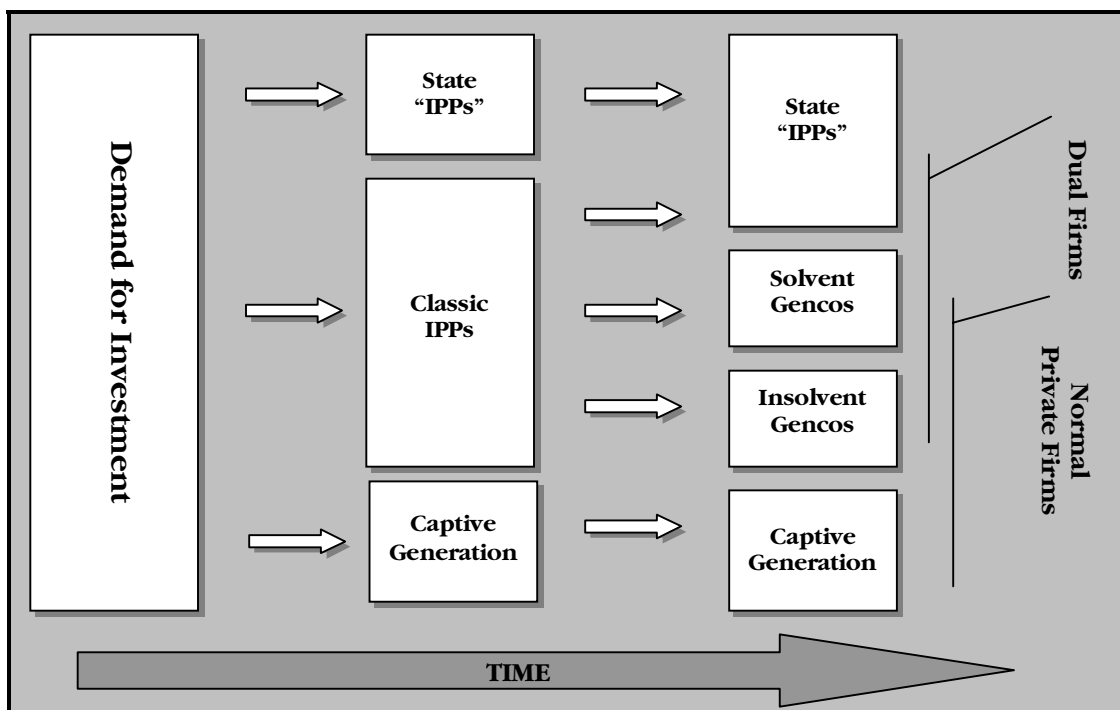
corporate scandals of the late 1990s); *IPP sector unravels on Enron Collapse, casts cloud over entire industry*, CORPORATE FINANCING WEEK (June 10, 2002).

⁶ Estimation based on calculations from the World Bank PPI Database.

The need for new power capacity along with a halting reform of the power sector has produced three types of enterprises that are often referred to as IPPs. Figure 2, below, summarizes the situation schematically. At the top are state dominated firms that masquerade as private firms, and increasingly compete with their fully private brethren. These enterprises attract the moniker “IPP” for various reasons, including the fact that some plants receive favorable tax or other treatment when they are viewed as IPPs. Often these plants are managed by the “dual firms” that emerged from a country’s restructuring process, and the desire to embrace something called an IPP is partly evidence of these firms’ savvy in seizing the latest management concepts in the power sector. In the extreme, all five of the state-owned generation companies created in China’s most recent reform of the power sector are formally called “IPP” although each firm is actually state-owned and state-controlled. This study is not focused on these generators because such plants do not confront many of the issues that comprise the focus of our study, such as the ability of private investors to enforce contract terms.

At the bottom are private generators that are not connected to the grid—often called “captive plants.” In some countries, these plants are regulated under the same law that governs grid-connected IPPs and thus often called “IPP.” (In Mexico, for example, the same IPP law is used for all privately built power plants whether or not the plant is designed principally to supply bulk power to customers via the grid.) Again, however, we do not focus on such plants in this study because the investor faces a different type of risk. Developers of captive projects work, usually, with a single private buyer and the enforcement of contracts is much easier, particularly when projects are developed for self-supply (as is often the case in India, Mexico, and the Philippines).

FIGURE 2: FORMS OF PRIVATE INVESTMENT IN THE POWER SECTOR



In the middle are “classic IPPs”, our quarry. These plants sell electricity under a long-term contract. In each of these cases, the key offtaker for the power is a state-owned (or state-regulated) electric utility, although in some cases, additional revenue is earned with sales to private distributors or large private users.

Classic IPPs are usually financed on a project basis, with a special purpose vehicle established to own and manage the IPP. The company draws equity from a number of foreign and domestic investors and secures debt from a syndicate of banks on the basis of expected revenues. Most projects are highly leveraged, with debt accounting for as large a share of project finance as the bank syndicate will tolerate.⁷

Developers and lenders entering these IPP arrangements knew that their ventures would be risky. To the extent possible, they sought to shift risk to the host government by relying on long term power purchase agreements (“PPAs”) and a host of other arrangements that they believed would insulate projects from the vagaries of government decision-making and unexpected changes in circumstance. They ran economic models that showed that the plants would be profitable so long as these minimum terms were met.

The architects of these deals usually demanded minimum offtake and tariff setting provisions. Where the offtaker was a state owned utility, a sovereign guarantee was often required to support their (usually) poor credit rating. Project documentation also usually shifted legal and regulatory risk to the government, typically through change-in-law provisions that indemnified investors for losses stemming from adverse legal or regulatory changes.

Because the electricity business generates revenues in local currency, while many of the cost components for IPPs such as capital, equipment and fuel, are set in hard currency the IPP investor is particularly sensitive to the allocation of currency risks. Arrangements addressing this mismatch have been a point of contention. In a typical deal, PPA payments are denominated in (or indexed to) a hard currency, but there are many types of currency arrangement and much of the variation in outcomes in the wake of large macroeconomic shocks depends on how this risk was managed.

Finally, the standard PPA also usually invoked international arbitration to settle disputes in order to avoid domestic courts that investors viewed as biased and capricious. These tools purported to focus responsibility for political risk in the hands of the party most able to tame political troubles—namely, the host government—although in practice we find that this risk is borne by the party least able to avoid having it thrust upon them. Risk was rampant, and builders and

⁷ We explore the attraction to high leveraging later, but one attraction to debt is rooted in the fear of expropriation. Many investors think that host countries are less likely to expropriate assets under the watchful eye of important banks, whereas they are more ready to offend the sensibility of risk equity. *See discussion, Section V.B.3., infra.*

operators of classic IPPs leaned heavily on contracts as the way to manage that risk.

B. A Theoretical Paradigm: The “Obsolescing Bargain.”

The generic problem of private investment in fixed capital where contracts are difficult to enforce is hardly a new issue. Indeed, for thirty years scholars have analyzed the peculiar risks that arise with capital-intensive investments—particularly those in settings where the enforceability of contracts is poor—through the lens of the ‘obsolescing bargain.’ The concept is simple. Negotiating leverage in a large private infrastructure project shifts during the project life cycle.⁸ Initially, the government needs private investors and thus offers attractive terms. Once operational, the investors face an amortization period of anywhere from 5 to 20 years to earn the full expected return. At the same time, the government has already secured what it needs (infrastructure); the original bargain has become obsolete. Theory predicts that the host will force a change in terms—either by outright nationalization or by squeezing revenue streams as far as possible. The original theory and its more recent embellishments have also underscored the role of expectations on both sides—bargains tend to become obsolete quickly for “one shot” investments, but ongoing ventures have a longer shadow of the future that (in principle) will dampen the incentives to expropriate an investment.

As a starting point, we note that the sample of IPPs we study have shown a wide array of adjustments to the original contractual arrangements—from outright cancellations, to official renegotiations to various other types of pressure (Table 1). The thesis of the obsolescing bargain has primed analysts to assume that these changes in deals will disfavor the investor and are evidence that attempts of expropriation are at work.⁹ We find that a blanket condemnation is premature, for the fundamental characteristics of investment in public utilities (including IPPs) introduce many uncertainties and stresses on contracts that are not solely the work of expropriation. In fact many instances of renegotiation are of mutual benefit, by making a project more competitive, by clarifying contract terms, or by otherwise making the investment more sustainable for both parties.

TABLE 1: ADJUSTMENTS TO CONTRACTS AND EXPECTATIONS IN THE IPP EXPERIENCE

⁸ The obsolescing bargain was originally proposed by Raymond Vernon in 1971. See VERNON, RAYMOND, *SOVEREIGNTY AT BAY: THE MULTINATIONAL SPREAD OF U.S. ENTERPRISES* (1971).

⁹ This emphasis is not limited to academic analysis, but is reflected in behavior by project sponsors and lenders. See, e.g., Wigmore, Gary S. and Susan E. Turner, *The Disappearing PPA: Moving to Merchant Power in Asia*, 19 J. OF ENERGY & NAT'L RES. L. 72, 73 (2001) (“[A] state owned utility’s failure to honour contract terms tends to erode investor and lender confidence in a host nation’s commitment to the rule of law, with resultant investor caution and higher cost of funds to be expected in the future”); Van Mejia, *The Philippines Re-Energizes: Privatization of the National Power Corporation and the Red Flag of Political Risk*, 16 COLUM. J. ASIAN L. 355, 363 (2003)(characterizing the 2001 review of IPP contracts in the Philippines “nothing more than an attempt to back out of contracts”).

| Government Action | Examples |
|---|--|
| <i>Cancellation</i> | Indonesia (six projects cancelled in aftermath of Asian financial crisis) India (Dabhol Power Company PPA cancelled) Philippines (mutual cancellation of San Pascual cogen project) |
| <i>Unilateral Changes to Original Agreement</i> | Argentina (“peso-ification” of infrastructure contracts) China (uniform tariff reductions) |
| <i>Renegotiation of original contracts</i> | Indonesia (most contracts renegotiated under pressure) Argentina (renegotiations incomplete, ongoing disputes) Thailand (renegotiation of contracts to benefit of investors) India (widespread corrections, adjustments to original agreements) |
| <i>Refusal to honor other obligations</i> | Brazil (repudiation of support obligations by Petrobras to thermal IPPs) India (refusal to honor state guarantee of Dabhol project) |
| <i>Regulatory or creeping expropriation</i> | Pakistan (delaying commissioning, imposing new taxes, slowing fuel delivery) Philippines (attempted elimination of VAT-exemption for IPPs) Brazil (decrees limiting offtake or contracting freedom of thermal plants) |
| <i>Otherwise altering leverage</i> | Philippines (unbundling rates and publishing inflated generation costs in bills) India (selective natural gas allocations to Andhra Pradesh IPPs) |

C. Regulated Utility Investment and the Social Contract.

The original obsolescing bargain model was developed the 1960s to account for widespread nationalizations of natural resources projects in the developing world, particularly in Latin America.¹⁰ While the basic observation about changing leverage during the life-cycle of an investment is readily transferable to the public infrastructure context, there are some key differences in the power sector that make direct application of the obsolescing bargain model to the IPP experience problematic.

First, for IPPs that rely on risk management through PPAs—as was the dominant model in the 1990s—nearly any change in circumstances will create pressure for a change in contract. Such changes may appear as obsolescing bargain phenomena when, in fact, other primal causes are at work. For example, consider the case of macroeconomic shock, which effects the revenues that flow to the investor, both through prices (which are affected by exchange rates) and through slack demand for power that typically accompanies periods of economic downturn. Under the “take-or-pay” provisions of typical PPAs, the macroeconomic context for a power plant presumably makes no difference—if the contract is enforced, project revenues for the most part do not depend on local prices or the actual level of power consumed.¹¹ Yet it is often impractical—especially when macroeconomic shocks create systemic trouble for state finances and draws political attention to contracts that become branded as sweetheart deals—for the host government to pursue any course other than renegotiating payment schedules, which requires re-opening the contract.

¹⁰ See VERNON, *supra* note 8.

¹¹ This is because the host government, offtaker or consumers (depending on the arrangements) absorb market and currency risk under the terms of most PPAs.

In contrast, with the natural resources projects of the 1970s that formed the original inspiration for the “obsolescing bargain” theory, investors did not attempt to manage market risk by allocating it to the government through offtake arrangements. Copper mines sold their product into international markets where, often, the very companies that owned the mines were major players; the investor could either hedge such risks themselves or had experience absorbing them as part of the normal business of trading in global commodities. For such classic mineral projects, a collapse in demand for the output of the project would be expressed as a collapse in demand; in contrast, for IPPs structured with long term PPAs, a collapse in demand creates pressure to renegotiate or cancel the project and thus looks like the obsolescing bargain.

Second, investment in the electricity sector is an activity that incurs exceedingly high political visibility—much more so than most private investments in factories or other activities that yield only private goods. Tariffs and service become part of a larger social contract implicit in electricity service,¹² and often such issues are highly politicized. Thus investors in IPPs may find additional unexpected obligations and changes in contractual terms that reflect the fact that social contracts are political goods without clear boundaries that can be neatly specified in legal contracts such as PPAs. Such changes may be driven by a range of pressures—from reasonable financial need to pure political opportunism—yet all will impose stress on the PPA.

Third, the regulation of electricity services is an extraordinarily complex and delicate process, requiring real time monitoring and response to variable conditions. Providing these functions in an objectively predictable manner requires strong institutions that operate according to codified norms—a tall order. Often key rules that govern power systems, such as dispatch and the handling of congestion, are invented “on the fly” in ways that even the most elaborate PPA could not anticipate or codify. Yet the aspiration for full description of risk sharing in PPAs—a key demand of investors, it appears—assures the need that original contractual terms will face pressure as the host country “learns” new rules for managing its power system. Inevitably, some of those new rules and arrangements will settle in ways that are unfavorable for the investor; for the PPA-centered firm, such outcomes will appear as regulatory expropriation.

Indeed, in the IPP sector, we find that adjustments are numerous and, in many cases, investors and hosts seem to prefer this outcome. Contractual inconsistency is not simply cynical opportunism.¹³ This may explain why, for

¹² See Thomas C. Heller, David G. Victor and Henri Tjong, *Electricity Restructuring and the Social Contract*, PESD Working Paper No. 15 (2003), available at <http://pesd.stanford.edu/publications/20203/>.

¹³ A recent study released by Standard & Poors, Citibank, ABN AMRO, Deutsche Bank, and Societe General found that, contrary to popular assumptions, project finance loans generally perform better than corporate loans—demonstrating lower default rates, and higher loan recovery rates post-default (“default” in this case encompasses *any* change in the contract, even mutual renegotiation). Chris Beale et al., *Credit Attributes of Project Finance*, 8 J. OF STRUCT. & PROJ. FIN. 5 (2002). One explanation for this finding would punctuate one of the main propositions of this paper—namely that instability and renegotiation are implicit in infrastructure investment, and that they are not

example, investors themselves often initiate renegotiation,¹⁴ or are willing to work with the government to find solutions when there is an obvious mismatch between contractual conditions and prevailing conditions.¹⁵

D. Selecting a Sample of Countries and Projects.

This study aims to explain the variation in outcomes for the IPP experience at two levels. First we examine a sample of countries that have had experience with IPPs. Second, within that sample of countries, we examine the experience for a sample of projects. Armed with the results from those two stages—countries, then projects—we proceed to a third and final task that is not rooted in history but rather looks to the future at the possible evolution of the industry.

We have paid close attention to the dangers of selection bias in choosing our samples of countries and projects. To guide the selection process, at the beginning of this study we identified a range of factors that we hypothesized could explain the variation in country and project performance. On the country level, we focused on the characteristics of the investment climate; we also examined the electricity market itself, including the types of market reforms that have been pursued and also the characteristics of major fuels. We also hypothesized that macroeconomic shock would affect country performance. We then compiled a list of all developing and reforming countries that have had at least one IPP, and from that large universe of more than fifty countries we chose a sample of ten that exhibited variation (as a group) on all the major factors that we hypothesized might explain outcomes. The research team performed a similar sampling exercise for projects in Africa, leading to the selection of three countries for study—a sample of countries that totals thirteen. The details of the selection process are reported elsewhere.¹⁶ Part IV of this paper works through each of those major factors and explains what we have found.

Armed with a sample of thirteen countries, we then selected a sample of IPPs within each country for more in-depth analysis. We were mindful that at this second stage of sampling—with projects, rather than countries, as the unit of analysis—the questions of interest are partly different. For this second stage of sampling, we compiled a list of the universe of projects in each of the thirteen countries and then selected for more in-depth analysis on factors such as the types of investors, financial structure, fuel and technology and power sales arrangements. Part V of this paper reviews our findings on all the major project-level variables that we studied.

equivalent to naked opportunism on the part of the host country. The sample was the entire project finance portfolio of Deutsche Bank, Citibank, ABN AMRO, and Societe Generale—24% of global project finance market for 1997-2002—although this sample does not distinguish developing country finance.

¹⁴ Guasch, J. Luis, Jean-Jacques Laffont and Stéphane Straub, *Renegotiation of Concession Contracts in Latin America*, World Bank Policy Research Working Paper 3011 (April 2003), at 2.

¹⁵ This statement reflects a common theme in our conversations with industry participants.

¹⁶ See Victor, David G., Thomas C. Heller, Joshua C. House, Pei Yee Woo, *The Experience of Independent Power Projects (IPPs) in Developing Countries: Introduction and Case Study Methods*, PESD Working Paper No. 23 (2003), available at <http://pesd.stanford.edu/publications/20528/>.

E. Measuring Outcomes.

The objective of this study—to explain the variation in IPP performance—merits some additional discussion. Our goal is to explain performance on two dimensions: the host country and the investor. In addition, we must explain performance for two levels of analysis: the country and the project. Unlike the physicist who can simply measure the velocity of a bouncing ball, it is much harder to measure the critical outcomes when the variables are comprised of many dimensions and objective data rarely exist. To solve this problem, we developed a checklist of indicators that the research team used to measure outcomes in each of these dimensions (Table 2).

TABLE 2: IPP STUDY RESEARCH GOALS

| Goal | Dependent variable (“outcomes”) | Indicators |
|--|---|--|
| <i>#1. To explain variation in country performance</i> | The success or failure of a <u>country</u> in attracting and maintaining private investment in the power sector | Investor behavior: Investor evaluation: Country behavior: Financial sustainability: |
| <i>#2. To explain variation in project performance</i> | The success or failure of a <u>project</u> to meet the reasonable expectations of key stakeholders (investors, lenders, host country policy makers) | Financial returns to investors: Technical performance: Adaptability under stress: Consistency with strategic goals: |

1. *Outcomes for Host Countries.*

From the host country perspective, we focus on three levels. First, we ask whether the country has succeeded in attracting investment that has satisfied realistic goals for privately-generated electricity. The primal impulse in IPP programs is to attract greenfield investment, and the basic indicator of success is whether such investment actually arrived. Second, we ask whether the price and quantity of private electricity, and other terms of the investment, are within a band of reasonable expectations for investors and hosts alike. Finally, we examine financial sustainability and explore whether the experiences of investors and hosts appears to be replicable for possible future rounds of investment. In examining these three broad aspects of country performance we rely on qualitative information such as gleaned from interviews, along with quantitative data—such as objective measures of electricity sector investment—where possible.

2. *Outcomes for Investors.*

In evaluating the experience of investors, we also focus on whether reasonable expectations have been met. Where financial data, or reliable proxies, are available we weigh financial performance. Often, however, such data are confidential or are aggregated in ways that make it difficult to examine the investor’s experience with a particular country or project. In these instances, we rely on other measures, such as the stability of contracts and the nature of adjustments and the record of payments; through interviews, we have elicited the assessments of the investors themselves, including assessments on whether their experience with particular countries and projects contributes to the firms’ strategic goals. Where possible, we have interviewed in-country as we have found often

large differences in the assessment of countries and projects when between the home base and field offices of foreign investors. In making these assessments of investor experiences, we have been mindful that “investors” is hardly a homogeneous group—it includes project builders and operators, banks, fuel suppliers and equipment vendors. It includes firms that specialize in these types of investments as well as generalists. Our samples of countries and projects aim to look across the many species that populate this ecosystem of investors.

3. *A Two-Dimensional View of Performance*

As we will show in detail through the rest of this paper, these two dimensions of IPP performance are not always correlated. Figure 3 shows a matrix, which we will populate with examples in Parts IV and V of this paper, which crosses the two dimensions. For now, we focus on the attributes of each cell in the matrix. The outcome for IPPs generally fall on an axis from the upper left box (good outcomes for investors and hosts) to the lower right (poor performance for both). However, as we will show, there are many examples that deviate from that axis. They include exploitation by investors (upper right) and by hosts (lower left)—situations that have animated much of the practice and analysis of private investment.

FIGURE 3: THE TWO-DIMENSIONS OF IPP OUTCOMES

| | Country Outcome POSITIVE | Country Outcome NEGATIVE |
|--------------------------------------|---|--|
| Investor Outcome POSITIVE | <p>Country attracts competitive and sustainable investment.</p> <p>Projects are paid and enforced as originally agreed.</p> | <p>Country IPP obligations excessive, unnecessary or expensive.</p> <p>Projects are paid and enforced as originally agreed.</p> |
| Investor Outcome NEGATIVE | <p>Country attracts investment that produces electricity.</p> <p>Private investors are squeezed out in favor of other actors.</p> | <p>Country IPP obligations excessive, unnecessary or expensive; or mismanagement deters future investment.</p> <p>Private investors are squeezed out in favor of other actors.</p> |

IV. EXPLAINING COUNTRY PERFORMANCE.

Even a brief glance across the global IPP investment record reveals wide variation in country performance. In this section, we explore the factors that appear to explain that variation, focusing on characteristics of the host country (so-called “country factors”). We begin by summarizing the actual performance with IPPs across our country sample (Subsection A). Next, we continue by examining

the primary factors that might explain this variation. These factors include the macroeconomic context (Subsection B), the management and structure of the host country electricity sector (Subsection C), and the host country investment climate (Subsection D).

A. A Review of Country Performance in the IPP Sector.

In Figure 5 we show how our sample of thirteen countries has scored on the two dimensions that we are using to measure performance—the experience of investors and of hosts. The richness of each country experience will emerge as our story develops; for now, however, we make four general observations about the variation in outcomes.

FIGURE 5: THE TWO-DIMENSIONS OF COUNTRY OUTCOMES

| | Country Outcome POSITIVE | Country Outcome NEGATIVE |
|---------------------|---|---|
| Investor Outcome | <p>Thailand</p> <p>Mexico</p> <p>Egypt</p> <p>Brazil (hydro IPPs)</p> <p>Argentina (pre-crisis)</p> <p>Turkey (BOOs)</p> <p>India (Andhra Pradesh)</p> <p>Philippines</p> | <p>Malaysia</p> <p>Turkey (BOTs)</p> |
| Investor Outcome | <p>China</p> <p>India (Maharashtra)</p> | <p>India (Gujarat)</p> <p>Poland</p> <p>Kenya</p> <p>Argentina (post crisis)</p> <p>Brazil (thermal IPPs)</p> <p>India (Tamil Nadu)</p> |

First, there is a large group of countries that, in general, populates the upper left corner. These countries have successfully attracted investment and have built largely stable relationships between government and investors. This group notably includes Mexico, Thailand and Egypt. In each of these countries the vast majority of projects that led to completed contracts have actually reached commercial operations, and the original contracts have largely held.¹⁷ This group is important for this study because these countries have extracted maximum value from the IPP arrangements, and the investors alike have generally gained returns that met their reasonable expectations. They are, in effect, the ideal outcome for the traditional IPP model—they are as good as it gets, and yet, in each case questions have arisen about the long-term sustainability of the such arrangements because in each the host government, as the single buyer of electricity, has assumed nearly all risks—notably foreign exchange liability, fuel supply and price risk, and market risk. The result being that the government has faced significant

¹⁷ The exception being Thailand, which by adjusting its PPAs to the benefit of investors to account for the shock of the Asian financial crisis, managed to navigate economic stress in a manner that maintained credibility with investors.

stress (e.g., Thailand, Egypt) or there are dark clouds on the horizon because the payment schemes that make IPPs attractive have resulted in a large accumulation of unfunded liabilities (Mexico).

At the margins of this group are countries in which the IPP program has addressed important needs, but where outcomes have been qualified by concerns surrounding high prices, lack of transparency, and in some cases popular or political backlash. This includes countries such as the Philippines, where the experience has been less positive because of severe difficulties in sustaining investment. The Philippines ranks highly for having attracted large investments into its power sector and also navigating the shocks of the Asian financial crisis in a way that has maintained the confidence of most IPP investors. Investors and the government alike have faced considerable challenges, including political controversy related to high prices and a sharp deterioration in the financial condition of the national utility, which has jeopardized the payments that IPP generators have expected. Currently, continued efforts at reform in the electricity sector have cast new uncertainty into the investment environment.

Second, at the opposite extreme, there are a few countries that have offered poor experiences for investors and hosts alike. The causes for these poor outcomes are varied, and that they are not simply cases of poor policy design or expropriation. In Poland, for example, the country began restructuring of the power market with modest goals for attracting investment in greenfield IPPs—indeed, only two IPPs of significant size were developed—but Poland found that it didn't even need these plants. It tried to cancel the PPAs but found itself barred from compensating the plant owners due to EU laws that limited such payments.

This lower right category also includes Kenya, which launched an IPP program in the midst of a severe power crisis. Saddled with a poor reputation and a large credit risk, Kenya was forced to sign very costly short term contracts for power generated from technologies that were particularly expensive. Subsequent projects improved on these terms somewhat, however, while Kenya continues to look towards the private sector for investment, government officials view the original projects as overpriced and a burden on the finances of the national utility, while many original investors have lost interest.

Third, the assessment of outcomes includes some countries that fit in the lower left box—an outcome that is similar to that predicted by the theory of the obsolescing bargain. China fits this theory most closely. In the early 1990s China needed foreign investment to keep up with soaring demand for power; the country extracted the available benefits of foreign investment and is now building power plants almost entirely with domestic funds. Indeed, in the last few years there has been about 40-50 GW of new capacity installed every year, essentially all financed with domestic capital. Further, China's access to FDI and to capital generally has not been affected by the difficult experiences in the IPP sector.

Fourth, there are some countries for which a “country” assessment of outcomes is must account for the fact that the IPP experience has been segmented. In Brazil, investors in hydropower projects are pleased, but those who have tried

to build gas-fired plants have all encountered severe difficulties with changing rules and the challenge of competing in a power pool with hydropower sources that have nearly zero short term marginal cost. Argentina has also seen a divided experience—not by fuel but over time. For ten years, Argentina’s privatization of the power sector had been successful and sustainable; the outcomes were lower prices, improved service, lighter burdens on the government’s capital budget, and an attractive business environment for private investors. However, the 2001-02 crisis has largely erased that success, with a series of bitter disputes emerging from the government’s aggressive policy towards foreign infrastructure investors. Recently, the prospect of inadequate power supplies, has forced the government to cut special deals with private generators for investment in new power capacity. Turkey has often adjusted its legal arrangements for IPPs in an effort to fine-tune the level of investment—thus it has been a positive experience for investors (but costly for the country) under an early IPP law and has improved under a later law. Some states in India exhibit characteristics of the obsolescing bargain even as others struggle to create a sustainable investment environment for the state and investors alike.

These stories emerge from some striking patterns in our assessment of outcomes. Establishing cause and effect more systematically, however, requires looking at each potential cause in turn—a task to which we now turn.

B. The Case of Macroeconomic Shock.

The most prominent single explanation for the collapse of the IPP market in the late 1990s is a succession of macroeconomic shocks—notably the Asian financial crisis, the related devaluation of the real in Brazil, and the Argentine meltdown in 2001-02. While macroeconomic stability is often included as part of the investment climate, which we examine later, here we focus on such shocks specifically due to their perceived dominance in explaining the IPP experience. We find that while macroeconomic shock has had a substantial effect on investors and hosts, government policies have played a large role in mediating the stress that is imposed on PPA contracts in the wake of a macroeconomic shock.

The particular impact of macroeconomic shock on an IPP sector is determined by a wide array of factors, including the severity of the crisis, the origin of fuel supply, the currency denomination of wholesale tariff, the extent of domestic financing, and amount and timing of IPP contracting, and the relationship between wholesale and retail tariffs.¹⁸ A breakdown of these factors within the countries in our sample appears in Table 3, below.

¹⁸ This discussion relies on a model first proposed in a policy note prepared for the World Bank and reproduced in various forms thereafter. See R. David Gray and John Schuster, *The East Asian Financial Crisis-Fallout for Private Power Projects*, Viewpoint, Note No. 146 (The World Bank, August 1998); Thierry Lefevre and Jessie L. Todoc, *IPPs in APEC Economies: Issues and Trends*, Paper Presented at “The Clean and Efficient Use of Fossil Energy for Power Generation in Thailand,” The Joint Either APEC Clean Fossil Energy Technical Seminar and Seventh APEC Coal Flow Seminar, APEC Clean Fossil Energy Experts’ Group, Bangkok, Thailand, October 30-November 3 (2000).

TABLE 3: EXPOSURE TO FOREIGN EXCHANGE RISK OF IPPS IN SELECTED COUNTRIES

| Exposure to... | | Foreign exchange risk | Foreign exchange risk | Foreign exchange risk | Market risk | Payment problems |
|----------------------------|--|---|-------------------------------------|-------------------------------------|---|--|
| Via... | <i>... severity of economic crisis</i> | <i>... origin of fuel supply</i> | <i>... currency of IPP payments</i> | <i>... foreign project debt</i> | <i>... proportion of power from IPPs</i> | <i>... retail tariff margin</i> |
| Indonesia 1997-98 | Rupiah lost 80% GDP growth -13% | LOW Indigenous | HIGH Hard currency | HIGH 14% local | HIGH 1055MW operating. 10000+ planned | HIGH. Retail tariffs not adequate. |
| Thailand 1997-98 | Baht lost 60% GDP growth -10% | HIGH Imported | LOW Local currency | LOW 75% local* | LOW 5900MW planned. 0MW operating. | LOW. Retail tariffs provide adequate margin. |
| Malaysia 1997-98 | Ringgit lost 50% GDP growth -7% | LOW Indigenous | LOW Local currency | LOW 90% local | HIGH 4277MW operating. 9044MW planned. | LOW. Retail tariffs provide adequate margin. |
| Philippines 1997-98 | Peso lost 35% GDP growth -0.5% | HIGH Imported | HIGH Hard currency | HIGH 3% local | HIGH 3676MW operating. 3000+MW planned. | HIGH. Retail tariffs not adequate. |
| Turkey 2001 | Lira lost 100% GDP growth -7.49% | HIGH Imported gas | HIGH Hard currency | HIGH Mostly foreign | HIGH. 1810MW operating. 5930MW planned. | MEDIUM. Persistent high cross-subsidy. |
| Egypt 2002-03 | Pound lost 50% GDP growth 3% | LOW Domestic | HIGH Hard currency | HIGH Local, but USD denominated | HIGH. 2051MW operating. | HIGH. Retail tariffs not adequate. |
| Argentina 2002 | Peso lost 200% GDP growth -10.89% | HIGH. Domestic, but dollar denominated | HIGH. Hard currency | MEDIUM. Limited project Finance. | HIGH. Almost 100% of electricity sector private. | LOW. Retail tariffs adequate until frozen. |

Source: Adapted from model first presented in R. David Gray and John Schuster, The East Asian Financial Crisis-Fallout for Private Power Projects, Viewpoint, Note No. 146 (The World Bank, August 1998); additional data based on PESD research.

The instances summarized in this table point to a wide array of scenarios by which macroeconomic shocks have affected IPPs. Most crucial to understanding these effects is analysis of the policies that governments implement in response. In Thailand, the epicenter of the Asian crisis, the weight of the baht's decline would have rested with the IPPs themselves, because the contracts were denominated in local currency. At the time of the crisis, no IPP was operational (some SPPs—private plants less than 90MW—were operational) and only one PPA (with International Power) had actually been signed. The effect of the crisis would have been to essentially end these projects—obtaining financing in the post-crisis environment was close to impossible. Investors, for their part, argued that floating the baht had triggered the change-in-law provisions in the PPAs (which, although unsigned, were largely agreed upon) which required indemnification for the loss flowing from the changing currency law. The

government, responding both to this argument and to the realization that the IPPs would basically evaporate without some support, agreed to index the IPP payments to the dollar. At the same time, the government also negotiated for a delay in the commercial operations date (COD) for many of the IPPs—which fit the IPPs needs anyway, because securing financing in the post-crisis environment was a laborious process even with indexed payments.

In Malaysia, the impact of the crisis on the IPPs, as observed above, was muted by the fact that most project costs were ringgit-denominated. However, Tenaga did find itself under substantial pressure due to its own foreign-denominated borrowing, which amounted to 40% of its total debts, or US\$2.2 billion. Further, the IPP contracts faced criticism (even from government officials) as being expensive and burdensome on the government—the IPPs there had not been competitively bid and were relatively more costly than EGAT’s private generators in Thailand.¹⁹ Despite rumblings from government and civil society,²⁰ available evidence suggests that the contracts were never altered—although with the government as the principal lender and minority shareholder in most of the projects, we speculate that adjustments may have been made in less transparent ways.

The Philippines also managed to navigate the fallout from the crisis with relative facility. Here, the impact of the crisis was less acute than in other South East Asian economies—where Thailand and Malaysia’s currencies spiked, the Philippine peso was already suffering a long and gradual loss of value dating from the early 1990s. However, with roughly 3000MW of largely dollar-denominated IPPs operating, and 3000MW on the way, the Philippines faced a serious and immediate impact on its power purchasing cost that none of its neighbors faced. Nevertheless, it was almost four years before the government made any moves to change the terms in the contracts—and then did so in a largely cooperative process with its IPPs. During this time, Napocor was regularly passing costs through to consumers via an adjustment mechanism; while retail tariffs were affected (becoming almost the highest in Asia at one time), Napocor’s solvency was not negatively impacted by its IPP obligations. Rather, beginning in 1999 the government began interfering with tariffs and the pass-through mechanism, reducing the first and capping the second, in a way that concentrated the insolvency of the electricity system on Napocor’s books. The spiraling debt of the state utility arguably forced the government’s hand in turning to the IPPs to seek concessions on the original contracts.

In contrast to the relatively positive stories in the Philippines, Malaysia and Thailand, experiences in Indonesia and Argentina have been notably less so. At

¹⁹ Albouy, Yves and Reda Bousba, *The Impact of IPPs in Developing Countries—Out of the Crisis and Into the Future*, Public Policy for the Private Sector Note No. 162 (The World Bank, December 1998).

²⁰ See, e.g., Report on Tenaga Nasional, *International Country Risk Guide – Asia and the Pacific*, Apr 1, 1997 (“Aggrieved over the rising profits of the IPPs, Tenaga began lobbying the government for more favorable treatment.”); S. Jayasankaran, *Lighting Tenaga’s Path: Malaysia grapples with an untenable power market*, FAR E. ECON. REV., Nov. 7, 1996, p. 93; S. Jayasankaran, *Kuala Lumpur: Price of Power*, FAR E. ECON. REV., Jan. 30, 1997.

the time of the crisis, Indonesia had only 1000MW operating and several thousand more megawatts in the development pipeline. However, the story of the acrimonious disputes that followed is inseparable from the mode in which most projects entered the Indonesian market—by partnering with members of then President Suharto’s family. A cloud of corruption and overpricing hung over the entire IPP sector and the post-Suharto administration had enormous incentives to take strong action. While the experience in the Philippines and Thailand suggests that a gentler government policy would have evoked a more flexible response from investors, the viability of such an option was eroded by the projects’ close association with the then-departed Suharto regime.

In Argentina, following the devastating economic collapse of 2001-02, the government froze infrastructure tariffs and converted all infrastructure contracts to pesos (which had lost 200% of its value against the dollar). Additionally, emergency economic measures imposed limits on the repatriation of profits by foreign investors,²¹ and forbade utilities from reducing services in response to their declining revenue.²² Additionally, the crisis dampened electricity demand—total consumption in Argentina, which had been growing about 5% per annum for most of the 1990s, slowed in 2001 and fell by roughly one billion kilowatt hours in 2002.²³ Falling demand led in turn to lower prices on the spot market.

Since this disastrous beginning, the government of Argentina has displayed little capacity (or perhaps little interest) to resolve the dispute with infrastructure investors. The government began trying to renegotiate in March 2002, but the dispute continued throughout the year, repeatedly stalling on the power companies’ demand to raise tariffs by 30% to offset the cost of the devaluation, while the emergency economic law of January 2002 forbade such increases unless accompanied by a renegotiation of the contracts that governed power sales. Between November 2002 and February 2003, President Duhalde did attempt to raise tariffs several times (by 9%), but was blocked by a series of legal challenges. The new Kirchner government has not moved quickly to complete these contract renegotiations and has moved its deadline twice (now standing at December 2005). Close to thirty arbitration claims have been filed against the Argentine government in recent years,²⁴ and power sector investors continue to rate the country very negatively.²⁵

Both Egypt and Turkey have also faced economic shock that washed over their IPP sector, making dollar-denominated payments more expensive and causing government officials to question the initial commitments. In both countries, the increasing costliness of the projects invited pressure on from

²¹ World Markets Research Council, *Country Report: Argentina* (Jan. 14, 2002).

²² World Markets Research Council, *Country Report: Argentina* (Nov. 22, 2004).

²³ Data from the Energy Information Administration, available at <http://www.eia.doe.gov>.

²⁴ Ada Karina Izaguirre, *Private Infrastructure*, Public Policy for the Private Sector Note No. 274 (World Bank, Sept. 2004).

²⁵ Ranjit Lamech and Kazim Saeed, *What International Investors Look for When Investing in Developing Countries*, Energy and Mining Sector Board Discussion Paper #6 (The World Bank, May 2003), at 7.

government officials to alter the contracts, although projects in both countries seem to have held, with small adjustments.

The implication of these cases is that IPPs can, and perhaps should be expected to, weather even severe macroeconomic shocks—if not unchanged, then with at least an intact and productive relationship between government and investor. We do not downplay the seriousness of such crises for either host countries or for investors. Price inflation for hard currency denominated power has undermined IPP outcomes for host governments and consumers, and has also contributed significantly to the current hesitance on the part of either governments or investors to accept this risk. However, there are many examples where governments have offered credible commitments to absorb risk or investors have been willing to share some pain when the sky falls. Dismal outcomes have largely flowed from poor decisions, or have been driven by collateral aspects of the investment experience (such as the involvement of the Suharto family in the Indonesian IPPs and the political transition in that country).

C. Power Market Structure and Reform.

The IPP drama unfolded almost entirely on the larger stage of electricity sector reform in the developing world. As countries move to reform their power sector, IPPs have been built in a wide variety of power market circumstances. (*Annex A provides a summary of the electricity sector investment context for IPPs across our country sample*). While the primal urge for IPPs was most often a bare need for investment, they were often also viewed as a critical first step in the reform process.²⁶ It is now generally recognized that IPPs have not met this expectation.²⁷

In this section we examine two major aspects of power sector reform—first, the larger reform process and the particular models adopted for reform; second, we examine the particular issues surrounding the IPP program.

1. *The electricity sector reform context.*

(a) The Single-Buyer Model.

Most countries that have instituted IPP programs have adopted a single-buyer model in which the IPP sell power under long-term contract to a single enterprise (usually a national utility) that transmits and distributes the electricity to final users. This mode has been attractive to many countries because it facilitates rapid investment while requiring a minimum of meaningful reform. Mindful that most power sector reforms arise in a time of crisis, and the single-buyer market allows the quick fix of securing additional generating capacity without the need to

²⁶ See, e.g., *Global Energy Sector Reform in Developing Countries: A Scorecard*, Joint UNDP/World Bank Energy Sector Management Assistance Program (The World Bank, July 1999) (“It was hoped that IPPs would indirectly (1) set an example to the rest of the energy sector and (2) eventually force the sector both to become more efficient and to be willing to embrace privatization of existing assets.”).

²⁷ *Id.*

address the more difficult tasks of unbundling the state utility or the creation of complicated power pool arrangements. Often these systems do not even pursue retail tariff reform. The disadvantages of the single buyer model, however, have been precisely that it generally requires the public sector to absorb substantial risks and may even stifle further reforms that would be needed to make the electricity sector solvent. Thus, in many cases, a single-buyer approach to IPPs may arguably replace an electricity crisis with a fiscal crisis.

This dynamic is illustrated in Mexico, Thailand and Egypt—all countries that have at the center of their power systems a large state utility whose finances are deeply intertwined with those of the government as a whole. In Mexico, CFE's budget actually comes from Congress each year, while in Thailand, the EGAT Act makes the national government responsible for all of EGAT's liabilities. In Egypt, numerous efforts at reform (beginning as far back as 1964) have produced uneven results (including a "re-bundling" of state companies into integrated utilities in 1998), but oversight has remained within a central government ministry, no independent regulator was created until 2000, and the various permutations of industrial organization that have been experimented with amount to re-packaging of state entities, with political control remaining consistent.

In all three countries the IPP sector has been successful in important ways. All three, relying partly on the government backed balance sheets of their utilities, attracted competitively bid projects that supply low cost electricity. All three countries have maintained strong payment records with respect to their IPPs under the original contracts (with the post-crisis indexation in Thailand). In general, investors rate all three countries highly as sites for investment.²⁸

The stability and attractiveness of the state-dominated single buyer model creates many hidden costs that governments, eventually, must manage. In Mexico, doubts are growing about the government's ability to sustain the streams of payments of its soaring liabilities for PPAs. In Egypt as in many countries, past promises to absorb currency risks are leading to a backlash against new IPPs. In Thailand, by contrast, the government has moved to keep the IPP program financially sustainable because EGAT (unlike CFE in Mexico or EEHC in Egypt) has largely been allowed to recover its purchased power costs. However, even here the politicization of power prices has caused a backlash that has led the government to flirt with the option of anointing state-controlled firms as the builders of new "IPPs," which would chill interest from investors not eager to compete on an uneven field.

Success with the single buyer model has occurred only where state utilities have been able to recover their power purchase costs; where state utilities have not been able to draw on state resources or engage in other financial engineering, their commitment to repay IPPs has not been credible and the investment experience has been much more uneven. Indeed, private generators in this context often exacerbate the insolvency of the state electricity companies, which find themselves stuck with large payment liabilities and no means (or desire or

²⁸ Lamech and Saeed, *supra* note 25, at 7.

political instruction) to pay them.²⁹ This has been the case in India with the almost universally bankrupt state electricity boards, and in the Philippines in the late 1990s, when politically motivated policy began depressing Napocor's ability to pass-through purchase costs.

(b) The Multi-Buyer Model.

The multiple buyer model predominated in Latin America, and in our sample is seen in Argentina, Brazil; at present, the Philippines is slowly introducing such a model. While a stable and wholly privatized multiple-buyer market, as in Argentina during 1992-2002 and still in Chile, probably delivers the most sustainable returns to the host country and to investors, these advanced markets are extremely difficult to establish and remain the exception. In the multiple-buyer framework it is comparatively difficult to isolate the IPP from broader market risk in the electricity sector. The IPP experience in this context depends heavily on the success of reforms generally.

Thus, in Argentina, private generators competed in a well structured market, providing returns to both investors (although narrow returns because of purchasers in Argentina largely relied on the intensely competitive spot market) and to the host government. The failure of this model stems almost entirely from mismanagement in other areas, principally reliance on the currency board that pegged the peso to the dollar as an artificial restraint on government expenditure.

In Brazil, the inability to craft a regulatory framework that is workable for thermal generators has haunted both government and investors. Driven by impending crisis in the late 1990s, the government offered generous incentives to investors to install thermal capacity that would bolster their overwhelmingly hydro-dependent electricity sector. These incentives ranged from having Petrobras guarantee minimum revenues to a series of priority thermal projects, to authorizing higher than usual pass through of purchase costs to distribution companies to encourage their owners to build thermal capacity. Not surprisingly, IPPs that fit neatly into the pre-existing market framework (i.e. hydro plants) perform better on average than plants on the cutting edge of the reform process (i.e. thermal plants in a system dominated by hydropower).

(c) Continuous and Ambiguous Reforms

In all of the countries that we have examined, the electricity sector remains in flux. With the exception of Argentina, the most common environment for a private power producer is one of partial reform—a hybrid market that combines elements of market activity with large state dominated sectors. In this context, instability is common; firms that thrive in that context are those able to operate in persistently politicized markets.

²⁹ For example, in India the crushing weight of unpaid receivables from state electricity boards to the national generation company, NTPC, became such that the federal government negotiated a settlement whereby the outstanding payments would be securitized as state-guaranteed bonds, for which NTPC would have the right to intervene in any disbursements from the central to the state government.

Two principal trajectories have emerged. In the first, countries with domestic resources seem to be re-trenching towards a managed electricity sector that is populated by state-controlled firms. This is the case in China and Thailand. Originally aggressive in seeking foreign IPP investment, China has dramatically reversed its initial enthusiasm for foreign IPPs in favor of supporting a series of state-controlled generating companies spun-off from the former State Power Corporation. In these shifting sands, foreign investors have generally fared poorly against domestic actors with access to concessionary finance and connections with local power authorities.³⁰

Similarly, in Thailand, the emergence of state-dominated spin-offs from national utility EGAT, and the potential entrance of state gas company (PTT) in the electricity market, has raised alarms among investors concerned about the value of competing on a playing field tilted by the presence of these quasi-public companies that enjoy an advantage due to their combination of political and market strength. Whereas in the first round of IPP tenders, EGCO was barred from participating, in the upcoming round there is growing unease about potential bids by EGCO, Ratchaburi and PTT in the tender. Already, these firms have made a dramatic entrance into the seven original IPPs—of which only two (Eastern Power and Glow Power) remain independent. Of particular concern in the next round is whether state gas monopoly PTT will be allowed to bid. In the first IPP tender, the issue of fuel arrangements was a sticky and contentious point that was sorted out only when EGAT agreed to sign a master fuel supply agreement with PTT for fuel to supply the gas-fired plants. With PTT potentially participating in the next round of bidding the fuel issue looms large. First, they may demand far more difficult terms for the IPPs than in the first round. Second, they may bid low because of their ability to manage the fuel risk better than anyone else. Third, PTT may favor its own IPPs in fuel allocations and prices once the plants are operating. If investors are not comforted that PTT will be restricted from making such moves, the second round of investment may be far less convincing than the first.

In the second pathway, several countries continue the reform process, aiming at increasing private involvement while eschewing a full merchant model. This is the case in the Philippines, Poland, and to a certain extent Brazil. In the Philippines, IPPs thrived in a single-buyer system; plans to overhaul the electricity sector began as early as 1995, but concrete steps were not taken until the 2001 EPIRA law laid the foundation for a transition to fully private multiple-buyer market. This process must contend with the challenge of integrating existing IPPs into what is envisioned as bilateral contract market with a spot market for balancing. Private generators with long term PPAs will nonetheless be required to compete in this market, but will be compensated for shortfalls in revenue beneath contracted amounts via a universal levy, which has raised the fear that predatory bidding will distort the spot market. Additionally, the bilateral contract market has been gridlocked as hundreds of small, private distribution cooperatives adjust to a

³⁰ Pei Yee Woo, *Recurring Dream or Incessant Nightmare?: Foreign Direct Investment in China's Power Industry* (2003)(unpublished thesis on file with PESD).

commercial environment for the first time—and worry, with reason, about contracting for power when large users are subject to poaching by generators selling directly. In this environment, competition is likely limited to actors willing and able to undertake the arduous task of selling power supply contracts to a hesitant and dispersed market. While in some ways a positive development, by placing a premium on local knowledge and commitment, it also limits potential investment drastically.

India blends the last two approaches. The Electricity Act of 2003 has been designed to transform the industry from a single-buyer market to a multi-buyer, multi-seller system—and in the process to remove the weak link of the state electricity boards that has undermined reform efforts to date. At the same time, domestic actors have emerged that are capable of mobilizing substantial investment in the electricity sector, including state-controlled NTPC, and private firms Reliance, Tata, GVK, and others.

Finally, some countries are continuing a single-buyer model without substantial reform plans. This is the case in Mexico, Kenya, Egypt, and Turkey. These countries, however, are increasingly confronting the systematic limitations of the model IPP framework that depends on foreign investment, and uncertainty looms over continued investment as government and investors grapple with risks no one wants to bear.

2. *Management of the IPP program.*

In addition to the architecture of the power sector itself, the variation in outcomes for IPPs also depends on the particular arrangements for private generators—what we call the IPP program. Governments have adopted a wide array of these programs; in some cases they have viewed IPPs as one-off arrangements, and in others they have created elaborate and permanent programs with competitive bidding and special market rules.

In most cases, the decision to invite private generation is driven mainly by the need for investment. However, countries have also pursued other goals, such as the discovery of a competitive benchmark, diversification of fuel mix, the attraction of novel technologies, and a reduction in prices. Measuring a country's experience with IPPs requires attention to its goals.

(a) Competitive bidding.

Countries have taken very different approaches to private bidding for IPPs. At one extreme are those that have combined the goal of attracting private investment with competition. In all these cases, competitive bidding has been a keystone to the IPP process. Thailand, Egypt and Mexico have attracted the most competitively priced private power in our sample; they have remained focused on the importance of low prices (among other goals). Because these countries have built their IPP programs prior to facing an immediate power crisis they have been able to reject unattractive offers—as Egypt did, for example, when it rejected Enron's sole bid to develop a project and opted, instead, for a competitive bid

system. In Thailand, roughly 50 bidders submitted 88 bids in the 1994 solicitation, out of which only 7 were chosen. In Egypt, 50 firms applied for prequalification in the Sidi Krir tender. In Mexico, the first 8 projects attracted 48 bids between them. While officials in Egypt and in Thailand, responding to the impact of respective financial crises, seek to reduce the government's exposure to foreign exchange risk in new IPP contracts, they still generally regard the first round projects as successes.

Although this observation should not be surprising, a striking number of countries nonetheless decide to eschew bidding and, rather, negotiate contracts directly. Often this situation arises when governments have failed to design a workable framework for private investment. Both Brazil and Turkey had substantial difficulty attracting the investment they needed until it was almost too late to avert a crisis—and certainly too late to benefit from strong investor interest. In Brazil, potential investors in thermal projects were wary of accepting take-or-pay contracts for gas supply when they were not confident that they could match those fuel commitments with power sales. This, and a host of other issues, stalled investment in such plants.³¹ In response, Brazil's state-owned gas company, Petrobras, was instructed to engineer a package of measures such as minimum revenue guarantees and fuel risk assumption) to induce some private investment in gas-fired power.

By the same token, early projects in Philippines and in India were negotiated in an environment with little or no competition. While we address the prickly question of whether these deals actually were too expensive elsewhere, for now we note that they certainly were (and are) widely perceived to be more expensive. While there are examples of negotiated deals that have been stable—many of the early Philippine projects, for example—the tenor of public discourse around them is noticeably more critical.³²

(b) Control over Contracting

Countries have also varied in their delegation of authority over contracting for IPPs. Those that have vested a central authority with control over the relationship with private generators have generally been able to manage most stresses that arise in for IPPs—provided that the stress is not so severe that it jeopardizes the entire solvency of the power sector. Thus, in the core single buyer countries such as in South East Asia and in Turkey, IPP development proceeded through various challenges until upended by the Asian financial crisis. This observation is amplified in the Philippines, which exhibits both forms. The larger “classic” IPPs signed agreements with the state utility Napocor (or Meralco, which though private is the dominant controller of distribution services in the country) were generally able to accommodate typical challenges in IPP management—such as enforcing offtake arrangements or addressing unreliable fuel supply from state enterprises. Serious challenges to the fundamental contract arrangements arose in

³¹ Dymond, Christopher and Ilse Pineda, *Brazilian Power Project Finance*, 7 J. OF PROJ. FIN. 29 (2001).

³² At the extreme, there is, of course, Indonesia, that essentially allocated projects to companies able to accept “local” partners—usually members or associates of the Suharto family.

response to macroeconomic crisis. In contrast, projects that set PPAs with subnational entities such as the export-processing zones or (somewhat strangely, as it is a national company) the Philippine National Oil Company,³³ have reported more chronic problems.

By contrast, through the 1990s India and China both delegated authority to state or provincial authorities. In these countries, difficulties such as the inability to enforce a contract often escalate into seemingly unsolvable chronic problems. In these environments, incentives within the host authorities often diverge, and different actors become responsible for key aspects of IPP management. In China, lack of transparency regarding authority over annual tariff reviews exacerbated the already difficult process, and made local protectionism more difficult to address. In India, there are often blurred relationships between state and central government officials on matters of reviewing costs or allocating fuel. Projects in both countries found themselves defending terms they though had been agreed previously, often unsure of where to turn.

Both countries have taken some steps to assert a greater degree of central control on IPPs. For example, IPPs in India are eager to secure classification as “mega” projects—which allows them to sell power to the Power Trading Corporation (PTC), a national government entity that sells power across states. Payment from the SEBs to PTC is supported with mandatory letters of credit and senior rights over central government funds to the states.³⁴ In China, IPPs struggled to operate in local environments where local actors enjoyed powerful advantages in securing dispatch for their plants. Substantial changes in the late 1990s focused on taking the IPPs out of the protected local context, far from Beijing’s oversight, and connecting them to larger regional grids, at least in part to remedy these problems. Thus, the offtaker for Shajiao C was changed from the Guangdong Electric Power Bureau to Yudean and Guangdian, entities that sell electricity to the regional South China Grid.

(c) Timing: An exogenous constraint on effective IPP policy.

The factors identified above are within the realm of decisions by government. The ability of a government to exert leverage over these policies, however, is constrained by a number of factors. Prominent among these is simply timing. When Thailand entered the IPP market, Asia was the hot market in the world, and Thailand was seen as particularly stable and attractive within Asia. Conversely, when Brazil began working to attract investment into thermal generation in the late 1990s, the major aggressive US firms were either overextended in Latin America or already reeling from the shock of the Asian

³³ For example, one of the only arbitrations in the Philippines grew out of CalEnergy’s two geothermal plants there, *see CalEnergy International and PNOG Energy Development Corp.*, Global Power Report (June 20, 2002). In the Philippines, the state maintains a monopoly over geothermal resources, so geothermal IPPs sign energy conversion agreements with PNOG, which owns and provides the steam and also purchases the electricity before on-selling to Napocor.

³⁴ *See, e.g.*, INTERNATIONAL ENERGY AGENCY, *ELECTRICITY IN INDIA: PROVIDING POWER FOR THE MILLIONS* (2002); Mark Riedy, *Project Finance India 2005: Overcoming Hurdles to Growth*, Andrews Kurth LLP Press Release (2005), available at http://akllp.com/Page.aspx?Doc_ID=2870.

financial crisis. Sponsors working in the mid-1990s complained that top-of-the-line equipment and contractors such as Siemens and GE would not even quote a price because their backlog was so long.

D. The Investment Climate.

The overwhelming focus that characterized the project finance and infrastructure investment boom of the 1990s was the mantra to: “identify risks and allocate them to the party most able to bear them.” Central to this task was the attempt to allocate all “country” risks to the country (usually via the state enterprise that purchased the power). In this section, we discuss the range of factors that comprise the investment climate—a broad collection of issues, many of which are often compiled together and discussed as “country risk.”

The definition and measurement of “country” risk have long been the subject of controversy. Many studies have explored the relationship between investment climate and aggregate levels of FDI in infrastructure;³⁵ to a lesser degree, analysts have examined the relationship between investment climate and the structure and management of investment.³⁶ Those studies show that, on an aggregate level, foreign investors behave as expected—higher levels of foreign capital flows to areas with better investment scores. Further, countries with higher investment scores are more likely to sustain foreign capital inflows, suggesting some relationship between these objective measures and the outcomes of investment.

We have not examined the relationship between broad measures of country risk and country performance because IPP projects are sufficiently large and specialized that their “investment climate” is probably comprised mainly of a set of more focused attributes. Risk, in any project, stems from the particular constellation of factors at work in the country, the project, and the investor, during

³⁵ See, e.g., Beatrice Weder and Mirjam Schiffer, “Catastrophic Political Risk versus Creeping Expropriation: A Cross-Country Analysis of Political and Regulatory Risks in Private Infrastructure Investments in LDCs,” Paper presented at the World Bank conference “Private Infrastructure for Development: Confronting Political and Regulatory Risks,” September 8-10, 1999, Rome, Italy (finding that investors weigh catastrophic risk—nationalization—more than creeping expropriation risks when deciding whether to invest in a given country); Aymo Brunetti and Beatrice Weder, *Investment and Institutional Uncertainty: A Comparative Study of Different Uncertainty Measures*, International Financial Corp. Technical Working Paper No. 4 (1997) (presenting quantitative analysis of a menu of investment climate indicators, and finding that weak rule of law, high corruption, volatility in real exchange rates have the strongest negative correlation with investment rates).

³⁶ See, e.g., Guy L. F. Holburn, *Political Risk, Political Capabilities and International Investment Strategy: Evidence from the Power Generation Market*, mimeo (2001)(finding that the decision to invest in electricity infrastructure in a given country is driven primarily by investor experience in similar countries and projects); Esty, Benjamin C. and William L. Megginson, *Creditor Rights Enforcement and Debt Ownership Structure: Evidence from the Global Syndicated Loan Market*, draft working paper, June 24, 2002 (finding that political risk is positively correlated with debt ownership structure).

the investment period.³⁷ For IPPs, we observe a fairly discrete list of factors that are prominent across our country sample. Here we identify five.

1. *Public finances and capacity to cover IPP payments.*

The introduction of IPPs into a single-buyer market (as most IPPs were) increases the firm cost basis of the state utility offtaker—the amount of money that must be paid on-time, every month, at a level that covers the PPA obligations. Unlike the previous integrated state-owned system, which in most cases did not cover costs and did not face a hard budget constraint, IPP payments create an obligation that must be covered with an increase in rates or some other source of revenue.

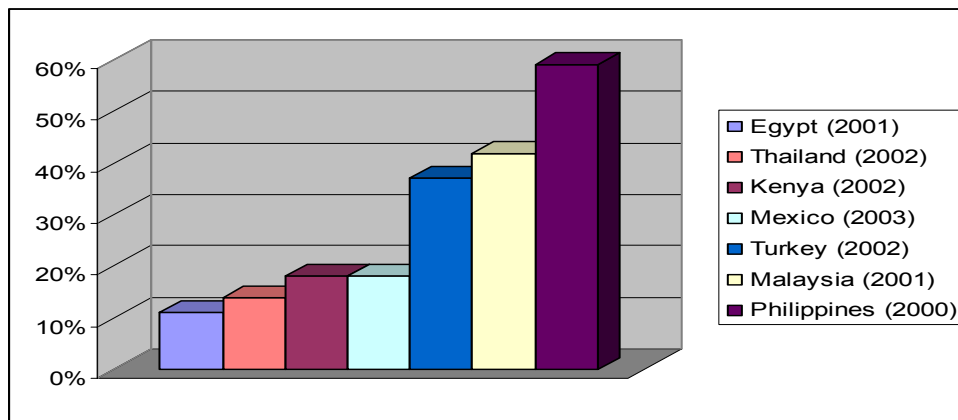
Where adequate pass-through mechanisms exist, this leads to increased prices for consumers. While these increases are not a trivial matter, countries with pass-through mechanisms have generally seen sustainable outcomes for investors and the hosts themselves. A full pass-through regime, however, often becomes unsustainable when the price rises are steep, as in instances of macroeconomic shock. Argentina is the obvious, although extreme, example. When the peso lost 200% of its value in a matter of months the government refused to let the cost get passed to consumers.

In most cases, a functioning pass-through to consumers performs well for a time before succumbing to political pressure of one form or another. Such was the case in the Philippines, where the pass-through mechanism absorbed nearly all PPA commitments until the government imposed a cap that forced Napocor to absorb the difference between PPA payments and lower than expected revenues. In Thailand, the pass-through mechanism for foreign exchange and fuel price fluctuations was enforced relatively consistently until recently, when the government asked the state utility EGAT to assume some of these payments. This change is correlated with a less aggressively pro-market government policy under the current government, but also with increasing amounts of IPP electricity coming online.

In all these cases, when the pass through mechanism has failed then the burdens of payments must shift either to the government (the offtaker) or to the IPP. The outcome often depends on whether the government has the financial wherewithal to cover the sudden subsidy that is needed. For this reason, some of the variation in country experience is related to the size of the IPP market as a fraction of the country's total generating portfolio. The best-performing countries not only utilize a single-buyer model, but in general they are cautious in their embrace of IPPs—they contract for a few projects and maintaining a smaller percentage of their total generating capacity in IPPs.

FIGURE 5: PRIVATE POWER GENERATION, % OF TOTAL³⁸

³⁷ Gerald T. West, *Managing project political risk: The role of investment insurance*, 2 J. OF PROJ. FIN. 5 (1996).



In Figure 5, all three of the best cases—Egypt, Thailand, and Mexico—cluster near the low end of the spectrum. In these cases, the IPP obligations are small enough in relation to the electricity sector or government budget as a whole that the increased costs are manageable—a strategy that is usually available only to countries where the IPP sector is small relative to total generation. The outlier at the low end—Kenya—was a late arriver to the IPP context, sought private investment under extremely adverse conditions (economic embargo from multilateral and foreign official lenders), and has contracted for diminutive IPPs in a diminutive electricity sector.

Still, financial strain is usually evident—in Egypt, IPP payments are covered at least in part by not paying state owned plants. This problem is particularly acute in Mexico, where the Pidiregas financing scheme—which keeps massive PPA liabilities off the government’s balance sheet—is coming under increasingly intense scrutiny, as lenders to CFE and to Mexico question the sustainability of the utility to continue underwriting its IPP obligations while maintaining subsidized retail tariffs. The system has lasted this long, at least in part, because CFE is under the direct budgetary control of the Mexican Congress, which oversees the utility’s finances as part of the national budget. If current growth in Mexico’s power sector is met substantially by private sector investment, CFE’s Pidiregas liability has been estimated to reach 60% of CFE’s book value and 3% of Mexico’s GDP within 10 years.³⁹

By contrast, both Turkey and the Philippines have had trouble managing the contingent liabilities imposed by their state-guaranteed IPP programs; in the Philippines, IPPs account for more than half of generation. These countries have felt the impact of devaluation extremely keenly; for example, in the first 6 months of the Philippines’ cap on the pass through of PPA costs, Napocor had to borrow US\$500 million to cover its shortfall.⁴⁰ The outlier on the upper end of the spectrum—

³⁸ Based on author’s calculations. Figures for Turkey include all privatized generation, not only greenfield development; figures for Thailand include the private “Small Power Producer” program; figures for Malaysia refer to Peninsular Malaysia only.

³⁹ Morgan Stanley Equity Research (Latin America), *Electric Utilities: Power to Converge*, Jan. 27, 2003, at 15.

⁴⁰ MYRNA VELASCO, *SURVIVING A POWER CRISIS: THE PHILIPPINE EXPERIENCE* 100 (forthcoming 2005).

Malaysia—relied almost exclusively on domestic inputs of capital and fuel, which also happened to minimize vulnerability to currency devaluation flowing from the IPP sector itself.

In Indian states, even those with a relatively high percentage of private generation by Indian standards, payment obligations to IPPs have in some cases been more manageable because of the small share of private capacity in the state dominated system. In Andhra Pradesh, IPPs account for only 12% of installed capacity, and in Gujarat only 10.5%. Although the relatively expensive price of undepreciated private plants here has attracted political attention and resulted in arguably manageable renegotiations, the state offtaker payment history has remained strong. By contrast, in 1999, the advisory branch of Indian rating agency Crisil estimated that if Tamil Nadu were to follow through on the 2,564MW of private projects that were in development (equivalent to 26% of installed capacity), the subsidy to keep the state electricity board solvent would need to double.⁴¹ Tamil Nadu has since produced what some observers call the “next Dabhol”; a simmering dispute between investors and the state government over unilateral and drastic tariff-reductions.⁴²

2. *A Viable Domestic Industry.*

The 1990s IPP market was built, in part, on the logic that private investors—notably foreign investors—were essential to financing, building and operating new generating capacity. The dependence on foreign investment reflected the sheer inability of the state system to maintain sufficient investment of its own, the immature development of domestic capital markets, and often an interest in foreign technology and management practices. Where these needs have declined, the fate of foreign IPPs has often followed suit.

In China, the government’s initial desire for private investment in the electricity sector was driven by the need to meet rapidly increasing demand for electricity as the economy took off in the late 1980s and 1990s, combined with a tight fiscal and credit situation domestically. Private capital streamed into the country’s electricity sector with more than \$9 billion invested in private power projects between 1990 and 1997. But by the late 1990s, the need for foreign capital had evaporated. China’s state dominated financial system was awash with capital; the State Power Corporation (and its later spinoff companies) along with key provinces were increasingly able to marshal resources for power investment on their own. Foreign investors fared poorly, facing repeated tariff reductions and unenforceable contracts. Under these circumstances, the weaknesses in the original contract and security arrangements began to show more prominently—China, in effect, squeezed the private investors and offers an example of the obsolescing bargain logic at work.

⁴¹ *Subsidy support to TNEB required to be doubled*, Business Line (The Hindu), October 25, 1999.

⁴² As of 2005, Tamil Nadu has 992MW of IPP capacity in operation, equivalent to slightly more than 10% of installed capacity. Further, the electricity board in the late 1990s was among the least insolvent of its peers, and maintained strong debt payment records. Economics are not all that is driving the dispute there.

In India, domestic companies including state-controlled NTPC and private firms such as Reliance, Tata, and regional firms such as GVK and Lanco, are mobilizing substantial investment in the electricity sector. These competitors reduce the need for, and interest in protecting, foreign investors. They also enjoy competitive advantages, such as political connections, that give potential foreign players pause. For example, NTPC has had its own problems with payment from the state electricity boards. However, because of its status as a central government entity, the mounting problem was solved with a global settlement that converted outstanding debt into state government-guaranteed bonds, and provided NTPC with senior rights in recovering further distributions from Delhi to the states; private firms, by contrast, are further down the line for payment. In another well-known example, the privatization of the Delhi distribution company linked tariff levels to the reduction of line losses, including the euphemistically termed “non-technical losses” representing theft of power. Imposing payment discipline on Delhi consumers is not a task many foreigners would relish.

3. *Management of fuel markets.*

The critical dependence of a thermal plant for a reliable fuel supply has often been an area of vulnerability for IPPs when fuel markets are unstable or inefficient. In an earlier study, PESD observed that the management of factor markets, particularly domestic fuel markets, has had a substantial impact on the ability of reformers in the electricity sector to alter the organization, efficiency and financial solvency of the state system. IPPs, often in the vanguard of reform within either unreformed or partially reformed systems, have in many cases borne the brunt of this challenge.

India presents a striking example of this. There is a curious prevalence of power plants firing on naphtha, a fuel that is little used elsewhere in the world for power generation. In the early days of India’s IPP program, potential investors faced enormous difficulties in securing fuel promises for thermal plants. Low grade Indian coal was abundant, but government agencies controlling coal and railways were leery of delivering to power producers after weathering repeated payment default from the SEBs; the railways were unable to make credible delivery commitments.⁴³ The major alternative was to import fuel, high import tariffs notwithstanding, and pass the increased fuel costs on to the state utilities (itself a risky proposition due to unpredictable import restrictions).⁴⁴

At the same time, the country was building up a surplus of domestically produced naphtha, due to uneven demand for petroleum byproducts.⁴⁵ In 1996, the Petroleum Ministry decided to allocate this naphtha to support the development of 12,000MW of combined cycle generation to be fired on natural gas and naphtha—despite limited gas supplies available at the time.⁴⁶ However, in 1998, when some naphtha burning plants had come online (e.g. Dabhol) and

⁴³ Navroz K. Dubash and Sudhir Chella Rajan, *The Politics of Power Sector Reform in India*, at 12, draft paper available at <http://pdf.wri.org/india.pdf>.

⁴⁴ *Id.*

⁴⁵ *Id.*

⁴⁶ Rahul Tongia, Stanford-CMU Indian Power Sector Reform Studies, at 12 (February 4, 2003).

several others were waiting in the wings (e.g. a series of tariff-bid projects in Andhra Pradesh), the government deregulated the price of naphtha, which doubled within the year as international prices of crude oil rose. The ensuing price increase for power purchased from naphtha-fired IPPs precipitated a host of problems between SEB's, which were reluctant to purchase the expensive electricity, and IPPs, which were suddenly vulnerable to pressure while struggling to secure a gas allocation.

Currently, some of the most stable projects in India have led the way in securing private gas supply contracts that have two-way take-or-pay provisions, in which the supplier will indemnify the power plant for the costs of failing to deliver. Essar Power and CLP Paguthan, both in Gujarat, have availed themselves of nearby private gasfield developments to secure such private contracts and move away from expensive naphtha firing. Essar had weathered the difficulties of running on naphtha in part because the project is primarily captive, providing power to a massive steel plant owned by the project developers. CLP Paguthan, on the other hand, had faced serious difficulties with the Gujarat Electricity Board while firing only on naphtha—after bringing down the tariff by running on natural gas, the dispute subsided and the GEBs payment record has improved.

Both Brazil and the Philippines found themselves in poor circumstances because of aggressive decisions to exploit available natural gas resources. In Brazil, the partly politicized decision to provide a market for natural gas from Bolivia was one of the early drivers of the priority thermal program there. The Philippines, eager to provide a market that would encourage Shell to develop the offshore Malampaya field (estimated to have gas reserves in the range of 400-450 million cubic feet per day for 20 years⁴⁷), pushed through several gas-fired IPPs. Contracts for these projects were signed in late 1997 just before the Asian financial crisis broke. As demand for power dipped between 1999-2002, Napocor operated with excess capacity, just as 2500MW of new natural gas-fired electricity came online along with another 800MW of new hydro power projects. Adding to the overcapacity woes that plagued Napocor, the costs for many of these projects fell directly on the state utility because a provision in the 2001 EPIRA law barred cost recovery for projects not registered with the ERB by Dec. 31, 2000; several of the gas-fired plants suffered from that provision. The ensuing drain on Napocor's finances contributed to public and political dissatisfaction with the power sector generally, and made the IPPs generally increasingly vulnerable to criticism.

Two of the most competitive IPP markets—Mexico and Thailand—have thus far had success using a master gas supply agreement that the national electricity utility (CFE in Mexico, EGAT in Thailand) would sign with the state-owned gas supplier (PEMEX in Mexico, PTT in Thailand). Such arrangements contributed to fuel market stability and fueled investor interest in those countries, but these arrangements have proved difficult to sustain. In Thailand, new tenders for IPPs are facing fresh difficulties securing competitive fuel contracts, not least because PTT is weighing a possible entry to the electricity market. In Mexico, the

⁴⁷ PRIVATE SOLUTIONS FOR INFRASTRUCTURE: OPPORTUNITIES FOR THE PHILIPPINES, Public-Private Infrastructure Advisory Facility & the World Bank Group (2000), at 23.

government has gradually moved away from forcing CFE to assume the risks associated with gas pricing (especially as gas prices have risen sharply since 2001), and current IPP guidelines shift substantially all fuel risk—including procurement, contracting, pricing, and quality—to the private operators.⁴⁸ Investors in Mexico now worry that they will be unable to compete directly with state-owned plants that have special fuel arrangements.

4. *The political climate and the role of civil society.*

Political and social concerns affect large energy infrastructure investments in a variety of ways. In our sample of countries, two principle trends have emerged: first, the impact of social opposition to private ownership and profit in public utilities; and second, the impact of a shifting political context on private power investment.

In many countries, public disapproval of IPP programs has been widespread, focusing on a range of concerns—from suspicions of corruption, to objections to high prices or perceived levels of profit, to environmental concerns (including siting, fuel choice, population displacement, and others). In Thailand, otherwise a haven for competitive private developers, violent protests against two coal fired projects led to their essential failure—they have been largely taken over by state-controlled companies, changed to natural gas, and relocated. A host of countries have seen popular dissatisfaction with IPPs lead to public or political investigation, including the Philippines, Kenya, India, Indonesia. Popular objection to IPPs is serious—farmers in Andhra Pradesh have committed suicide in protesting the IPPs in that state.

However, operating projects have not been affected by such opposition, unless accompanied by some other trouble, such as macroeconomic shock, or a heavy taint of corruption. More often, these issues affect the electricity reform process generally, and may filter through to the IPPs by affecting regulatory decisions such as allowances for the pass-through of costs, or preventing management reform (and therefore revenue generation) of state-owned utilities. Where IPPs themselves become particularly high profile objects of popular concern—as in the Philippines and in India—local authorities face the delicate process of “doing something” about the IPPs while maintaining investor confidence. In those countries, politically high profile negotiations have been presented as victories for the host government, yet produced results that reflect a give-and-take with investors. The first Dabhol renegotiation falls into this category, as well as the 2002-03 renegotiation process in the Philippines (*discussed in more detail on pp. 47, below*).

Second, in many countries, political tides have begun to disfavor the IPPs of the past, driven in many cases by troubles with those projects. This is the case in Argentina, Egypt, Thailand, China, and India. While not a reaction against private ownership *per se*, this trend can adversely affect the viability of existing IPPs (e.g.

⁴⁸ John Schuster and Bob Marcum, *Emerging Fuel Supply Issues in Mexican IPP Project Financing*, 8 J. of Struct. & Proj. Fin. 40, 42 (2002).

China, India) or plans for expansion of existing plants (e.g. Thailand, the Philippines, Egypt). In Thailand, for example, the government's efforts to prepare another round of IPP contracts is being viewed warily despite the assessment by both government and investors that the first round was a qualified success. That first round of IPPs weathered the Asian crisis and has begun delivering electricity to EGAT and reasonable returns to investors. On the government side, the concerns are partly technical—focusing particularly on the management of foreign exchange risk. However, for both the government and investors, the political and institutional context for private investment in electricity has shifted since the mid-1990s. In particular, the current Prime Minister Thaksin Shinawatra has emphatically backed away from the ambitious liberalization of the electricity sector espoused by his predecessor.⁴⁹ While plans for the delicate privatization of EGAT move ahead, the market context for foreign investment in IPPs remains clouded with concerns over the participation of “state champion” firms EGCO, Ratchaburi and PTT.

5. *The Importance of the Legal Framework.*

IPPs are often in the vanguard of reform, entering countries that are in the process of transforming their economies from an old state-dominated system to a new market oriented framework. Because of this, both investors and governments have been keen to isolate projects as much as possible from the surrounding context, carving out specific legal space for private power producers. Getting the legal framework right is a difficult process, and has affected outcomes for investors and hosts alike.

Where investors generally withhold capital pending the establishment of a favorable legal framework, countries often respond. In Turkey, the initial BOT law for private investment in power was passed in 1984, but ten years passed before the first deal was signed. Among the factors causing delay was the Constitutional Court's interpretation of relevant law, limiting private participation in public services to concession contracts, which were subject to a dizzying array of overlapping approvals. In 1994, facing an electricity crisis, the Turkish government passed a new BOT framework, this time offering sovereign guarantees for offtake requirements and specifying that the contracts would be governed by private law, and not as concessions, in order to bypass the burdensome requirements of the rest of the Turkish electricity sector. Although several IPP contracts were signed under this framework, the Constitutional Court struck down the private law distinction.⁵⁰ Thus, in 1997, the Turkish Parliament passed a law creating a “BO” framework for IPP investment, allowing 100% sovereign guarantees, and for the first time allowing recourse to international arbitration. Since 1997, 6000MW of foreign-sponsored IPP generating capacity has been added to the Turkish grid. While substantial pressure has now grown up around the

⁴⁹ See, e.g., Chuenchom Sangarasri Greacen and Chris Greacen, *Thailand's Electricity Reforms: Privatization of Benefits and Socialization of Costs and Risks*, PAC. AFF., Vol. 77, No. 3 (Fall 2004).

⁵⁰ Because the IPP contracts had been signed before the Court decision, however, they were allowed to retain their private status.

projects, the contracts have largely held, and continued to define the relationship between investor and government.⁵¹

The problem is that investment often flowed to countries that left large gaps in the legal framework for IPPs. Where investors have overlooked such risks, or accepted them, outcomes have been more difficult. The almost mythic “unenforceable” contract exists in its most pure form in China. Administrative regulations there subjected IPPs to yearly tariff reviews that programmed uncertainty into the deals. Final authority for deciding tariffs was often unclear, resting somewhere among local authorities in the power bureau and provincial government, and national authorities in Beijing. Unable to allocate the tariff setting risk to the government as IPPs in most other countries did, investors streamed into China anyway, and contented themselves with a variety of improvised tools intended to “keep people honest” in the words of one participant.

The most common of these were contractual arrangements between foreign and local partners. In China, most projects were required to carry substantial local participation, which often came from entities closely bound with local government. Thus, a common mechanism to protect foreigners would pass tariff reductions onto the local partner by reducing any available revenue stream—in some cases the EPC payments (*e.g.* the Shandong Zhonghua project), or equity dividends (*e.g.* Mirant’s Shajiao C project). In the cases we know of this strategy has been successful. For example, in the Shajiao C project, the offtaker (Guangdong Electric Power Bureau), the relevant regulatory authority (Guangdong Provincial Price Bureau), and the majority equity holder (Guangdong Shajiao, a corporatized state owned entity) were all connected to the Guangdong provincial government. When the Price Bureau began demanding price reductions from IPPs in Guangdong, the renegotiation triggered a clause in the joint venture agreement between Guangdong Shajiao and Mirant that required Guangdong Shajiao to “make whole” any loss suffered by the foreign investor. Thus, the money saved by the province in lowering offtake costs was reimbursed out of the pocket of the equity share of a government-owned entity. While accounts of these types of mechanisms are common, they critically depend on the enforcement of contracts, and we are skeptical that their overall protection has been strong.

V. EXPLAINING PROJECT PERFORMANCE.

A. Overview.

Specific projects exhibit a wide range of variation, both within and between countries, in meeting the reasonable expectations of investors and hosts. Figure 6 shows our assessment of the outcomes for a sample of the approximately 35 projects that we examined. (*Annex B details these projects*).

⁵¹ Even the best of these mechanisms have their limits. Where projects find themselves outside of the supposedly sealed world of special IPP arrangements, foreigners find themselves once again on an uneven playing field. Bankruptcy proceedings for projects in the Philippines or in India, or corporate law disputes between investors in project in India and Brazil, often leave projects in unhappy territory.

FIGURE 6: THE TWO-DIMENSIONS OF PROJECT OUTCOMES

| | Country Outcome GOOD | Country Outcome POOR |
|--------------------------|---|--|
| Investor Outcome GOOD | Merida III (Mexico) Rio Bravo II (Mexico) Eastern Power (Thailand) Quezon Power (Philippines) Gebze, Adapazari, Izmir (Turkey) GVK (India) | Sidi Krir (Egypt) Trakya (Turkey) |
| Investor Outcome POOR | Meizhou Wan (China) Samalpatti (India) | Elcho (Poland) Macaé (Brazil) Karaha Bodas (Indonesia) Dabhol (India) |

Most projects in our sample fall on the axis from northwest (positive outcomes for host and investor alike) to the southeast (poor for both). This pattern may reflect three factors at work. First, the northeast cell is unstable for projects—it would be populated by projects that are unreasonably burdensome for the host country yet are paid according to the investors’ expectations. Projects such as the Dabhol plant that would occupy that box appear to unravel quickly and then head either to the south east (if the contract terms are not adjusted) or to the west (if the terms are adjusted). Second, the southwest cell is unstable for countries. It can be populated under only special circumstances—where the country does not mind (or is unable to avert) the reputation of exploiting investors; in our sample, perhaps only China can exhibit such behavior because after the first round of IPPs the Chinese government no longer needs outside investors. Third, the northwest-southeast axis may reflect a measurement bias in our study. It is extremely difficult to assess whether PPAs are too costly because there is no objective benchmark for what are often first-of-a-kind projects; some projects that we have scored as good for a country may, with closer scrutiny, be examples of over-pricing by investors.

In this part, we aim to explain the variation in project outcomes. The 1990s were a period of great experimentation with power sales agreements, financing terms, foreign exchange management, and other factors that we expected would explain project outcomes. In the first section, we examine the major elements of standard IPP contracts—the structure of power sales arrangements, security mechanisms and financing structure—through which most investors attempted to allocate risks that governments could control to the governments themselves. (Fuel supply arrangements, which we examined earlier, are also important elements of standard IPP contracts.) Some of the variation in project outcomes is explained by variations in these basic project structures—a point that we explore in the first section, which addresses the main elements of standard IPP

arrangements. Next, we address the commercial context in which IPPs sell their power, focusing on how IPPs compare with the cost of other power supplies available to the country. Finally, we examine the ways that investors and host governments have tried to manage their relationship, including the enforcement of contracts.

B. Major Elements of the “Standard” IPP.

1. *Power sales arrangements.*

The model IPP sold electricity under a long term contract with minimum offtake and tariff setting provisions. Projects that deviated from this norm often fared poorly. For example, all IPPs in China faced annual tariff reviews that allowed local authorities to change tariffs easily, with little recourse for investors. Often, Chinese authorities succeeded in having a plant built and then squeezing the tariff down, leaving bitter memories for the foreigner but paying little price in the long run. In the Philippines, two projects developed during the early 1990s power crisis to sell electricity to export processing zones. These investors accepted price risks by allowing a tariff that would be indexed to the national grid price.⁵² Each of these projects has run into problems as Napocor’s rate-of-return was eroded progressively during the 1990s.⁵³ In 2002, the parent company wrote off the entire investment in each.⁵⁴ In these cases, deviation from the standard model—a long-term contract with a specified tariff—amplified the price risk.

On the other hand, some IPPs have been able to manage these market risks by sharing their production between the grid (i.e., the standard IPP arrangement) and private customers. In India, this has provided tangible benefits for at least one plant, which is operated by selling baseload power to the captive customer (a large steel mill), which allows the plant to remain online at a high load factor and ready to meet short term calls for peak and balancing loads as requested by the grid operator. In Mexico, we see a similar result but for quite different reasons. There, the bidding for CFE’s projects is so competitive that generators often must avail themselves of a new provision that allows them to install extra capacity for direct sales to large users. Revenue from these “extra” sales subsidize the grid. Increasingly, countries are moving towards this type of arrangement where public (grid) and private customers compete for power from the same plants.

2. *Security arrangements.*

The special purpose vehicles that are typically established for each IPP have relied on a wide array of arrangements to secure payments. They include sovereign guarantees for offtaker performance, escrow arrangements and letters of credit. All of these are designed to provide confidence around a predictable stream of payments for project partners.

⁵² Covanta Energy, Form 10-K (2003).

⁵³ Although these projects have been mired in controversy, it is somewhat strange to note that such extensive private acceptance of risk might be precisely what a country needs in an IPP program.

⁵⁴ Covanta Energy, Form 10-K, at 23-24 (2005).

Many of the countries in our sample, for example Egypt, Turkey, and the Philippines have extended explicit sovereign guarantees for IPPs. In addition to these cases, the projects in Mexico and Thailand have *de facto* guarantees, because the state-owned utilities that purchase the power (CFE and EGAT) are both supported by the national budget in their respective countries. These arrangements are associated with strong country performance, even in the face of macroeconomic stress, however, in light of competing factors at work in these countries, and we are skeptical that reliance on guarantees has been a significant factor.

In general, governments have objected to these arrangements, and many countries attempted to phase out the most demanding security provisions (notably sovereign guarantees) as the IPP sector matured. State utilities have often chafed at tariff guarantees that they view as subsidies for IPPs. Brazil's priority thermal projects burdened Petrobras with onerous guarantees to foreign IPPs; after bitter resistance, such arrangements have often ended in arbitration. It remains to be seen how Mexico handles the growing liabilities under its payment security scheme (known as PIDIREGAS); investors and lenders are growing increasingly skeptical, which would suggest that PIDIREGAS promises are declining in credibility.

In India, in addition to sovereign payment guarantees, investors relied on escrow arrangements or letters of credit to ensure payment. These mechanisms have not performed well, often because the relevant authorities have simply refused to implement their provisions. In every Indian IPP project that we have examined we found no instance where such security provisions were actually utilized in an attempt to force payments—even when the elaborate financial engineering had been done to put the mechanism in place and the investors were suffering from payment failures. In cases where projects have received central government guarantees, the record is uneven. Dabhol has certainly not been saved by the overlapping guarantees it received from state and central government authorities. Driven in part by the controversy created by the Dabhol guarantee, the central government scaled back guarantees for subsequent projects—GVK and ST-CMS, as far as we know, received only guarantees for foreign debt service payments. In both cases these payments have been met, but the guarantee has not been clearly relevant—GVK has enjoyed a relatively stable relationship with AP Transco, and in the case of ST-CMS, all of the projects in Tamil Nadu have received debt service coverage from the TNEB.

Where security is scarce, investors often internalize these arrangements. In China, investors tended to rely on arrangements that shifted the risk of payment shortfalls to local partners. For example, in Shajiao C, a mechanism of this nature called for indemnification of the foreign investor for reductions in the tariff. When provincial authorities lowered the applicable grid rate, the local partner (which was essentially an arm of the state government) paid the difference under the indemnification clause. We examine such local partner strategies in more detail below.

3. *Financing arrangements.*

The typical IPP was financed on a project basis and secured as much debt as syndicate of lenders would allow; debt levels often approached 70-80%. Although reliance on heavy doses of debt reflects a range of motivations, including the possibility of maximizing equity returns, in the developing country context there is another goal at work. Investors expect, or hope, that the involvement of financial institutions (particularly large international banks and multilateral development banks) would deter host governments from squeezing the IPPs opportunistically.⁵⁵ Indeed, every government official interviewed for this study identified debt payments as a lower limit for renegotiations. Even in cases as extreme as Tamil Nadu—where the government routinely squeezed projects—*ad hoc* payments to cover debt service requirements were commonplace.

However, high levels of debt also increase the brittleness of the project structure in the face of stress.⁵⁶ Highly geared project financing is sensitive to any instability in revenue; virtually every dollar of revenue is already allocated before it comes in and even small changes register loudly in the contractual structure that governs this allocation. The debt holders who bear most of the downside risk are extremely cash flow sensitive because of the limited recourse nature of the project company.⁵⁷ These characteristics are exacerbated in the developing country context. First, because of the limited recourse nature of project finance, restrictive loan covenants common to all lending tend to be stricter in these deals,⁵⁸ for example, often containing “institutional environmental provisions” that trigger redemption or take-over rights when there is a change in the underlying regulatory or legal environment.⁵⁹ In addition to the terms of loan documentation, the structure of lending syndicates may be different as well. Banks respond to developing country risk by arranging ever larger lending syndicates—with each

⁵⁵ See, e.g., THEODORE MORAN, *Lessons in the Management of International Political Risk from the Natural Resource and Private Infrastructure Sectors*, in *MANAGING INTERNATIONAL POLITICAL RISK* 70, 78 (Theodore H. Moran, ed., 1998).

⁵⁶ Concerns about heavy reliance on debt are beginning to crystallize in some quarters, after percolating for years in vague terms. On the first point, see Luis Correia da Silva, Antonio Estache, Sakari Jarvela, *Is debt replacing equity in regulated privatized infrastructure in developing countries?*, World Bank Policy Research Working Paper No. 3374 (2004). On the second point, see, e.g., Ada Karina Izaguirre, *Private Participation in Energy, Public Policy for the Private Sector Note No. 208* (World Bank, Washington, DC, 2000), at 4 (“[t]his frenzied approach to lending ‘resulted in lenders downplaying the role of sponsor equity through overleveraging of projects, the loosening of project structure, and a failure to adequately assess the fundamentals of long-term country risk and to take a sufficiently long-term view of the nature and values of such assets’”).

⁵⁷ Albouy, Yves and Reda Bousba, *The Impact of IPPs in Developing Countries—Out of the Crisis and Into the Future*, Public Policy for the Private Sector Note No. 162, The World Bank (Dec. 1998), at 7 (“In contrast to balance sheet financing, project finance can mobilize little equity. And since it offers lenders mostly downside risks, they subject it to a minute assessment and allocate these risks conservatively”). One study examined 210 projects in 37 countries, and found that low debt-service coverage ratio (“DSCR”) is correlated with project default, but that this relationship is significantly stronger when combined with other factors (country risk, economic contagion) that impact project viability. Klompjan, Richard and Marc J.F. Wouters, *Default Risk in Project Finance*, 8 J. OF STRUCT. & PROJ. FIN. 10, at 10, 20 (2002).

⁵⁸ Dailiami, Mansoor and Robert Hauswald, *The Emerging Project Bond Market: Covenant Provisions and Credit Spreads*, World Bank Policy Research Working Paper 3095 (July 2003), at 10.

⁵⁹ *Id.* at 9.

bank holding a smaller share of project debt.⁶⁰ As the numbers of debt holders increases, it becomes more expensive and difficult to restructure a project.⁶¹

This dynamic is significant because, in the face of stress, IPPs have most often engineered some flexibility in two ways: (1) restructuring their financing arrangements, and (2) renegotiating their fuel contracts. In practice, such restructuring requires a delicate negotiation between host country authorities, project managers, equity and debt holders, and other stakeholders such as EPC contractors and fuel suppliers.⁶² Officially, such commercial restructuring occurs between the project company and the host government; in practice, each stakeholder monitors the process carefully, and may hold a veto. The relations between these parties are largely governed by the relevant contracts and their dispute resolution provisions—an interlocking regime of reporting and consent obligations and contractual remedies that seems ill-suited to the delicate process of renegotiating contracts in the uncertain legal and business environment of a foreign country. Such fine-tuned financial and legal engineering may explain the strikingly high frequency of technical defaults across the IPP experience. The vast majority of projects examined in the study have experienced periods of technical default under their loan agreements, while actually missing a debt service payment remains a rare occurrence.

Evidence of the cost that such gridlock imposes on projects has been difficult to obtain because it resides in the most sensitive moments of already sensitive projects. This phenomenon has been noted in some well-documented cases. In Enron's Dabhol plant in India, for example, the project entered technical and real default under various agreements almost immediately upon the MSEB's failure to make payments under the PPA, and lenders resultant suspension of disbursements related to Phase II of the project, which induced an additional default, this time to the projects EPC contractor. From this dismal beginning, in addition to intransigence by Indian government officials, the project company reportedly was also unable to coordinate action among project stakeholders to develop a renegotiation strategy and the project slipped into deep default.⁶³

⁶⁰ Esty, Benjamin C. and William L. Megginson, *Creditor Rights Enforcement and Debt Ownership Structure: Evidence from the Global Syndicated Loan Market* (draft working paper, June 24, 2002) at 18.

⁶¹ *Id.* Additionally, as country risk deepens beyond the point of commercial viability, many sponsors and lenders turn to multilateral credit enhancements (such as guarantees from MIGA or OPIC) to increase the debt capacity of a particular project. One study finds that the availability of credit enhancements is the most significant variable associated with higher levels of debt in countries with weak institutional environments. Devapriya, K.A.K. and H. Wilhelm Alfen, *Role of Institutional Arrangements in Financing Project Companies in Asia* (draft working paper, Oct. 2, 2003). As uncertainty increases, multilaterals step in and allow projects to become more leveraged. The problem is that if the above observations are true, this leverage also makes the project more brittle, and does so precisely in circumstances likely to breed instability.

⁶² See generally, Kargman, Steven T., *Restructuring Troubled Power Projects in the Emerging Markets*, 8 J. OF STRUCT. & PROJ. FIN. 19 (2002).

⁶³ Piyush Joshi, *Dabhol: A Case Study of Restructuring Infrastructure Projects*, 8 J. OF STRUCT. & PROJ. FIN. 27 (2002).

To extend this analysis of the effects of project financing on the brittleness of projects, we suggest two areas for additional research. First, in some jurisdictions there have been stresses that have affected IPPs within the jurisdiction in quite different ways—allowing for a natural experiment that could be used to test whether and how the financial engineering affects project outcomes. An unfolding drama between the IPP and local authorities in Tamil Nadu offers one opportunity. Facing identically dismal treatment by the state electricity board, each IPP in Tamil Nadu has fared somewhat differently, and the ease of flexible refinancing may have contributed to these outcomes. (To date we have not been able to map with sufficient precision the experience of each project to arrive at firm conclusions.)

Second, in Latin America the proportion of projects that included less or no project debt was substantially higher than in Asia. Examining the performance of projects in Brazil and Argentina to pressure from host government authorities may yield valuable insight into the impact of reduced leverage in the IPP context. This work will take place during June 2005.

C. Host Market Fundamentals.

Most of the variation in project experiences is due to fundamental economic characteristics of the market in which IPPs sell their power—in particular, cost. In this section, we introduce the importance of these fundamental factors and then explore whether IPPs are destined to be high-cost suppliers.

1. *The (Qualified) Primacy of Cost.*

When describing the potential benefits of IPPs, hosts and investors alike usually cite a wide array of factors. They include diversity in fuel mixes, environmental efficiency, access to sophisticated technology, and even collateral public goods such as irrigation water from hydroelectric plants. In practice, however, these benefits have played a relatively minor role in explaining project outcomes; what matters much more is cost.

At the early bidding or project negotiation stages, project developers often appear to have focused on getting the best contract rather than situating an IPP competitively within the host electricity sector. The result has been projects that defy normal commercial principals and are prone to explode as host utilities and governments focus on the difference between project arrangements and the rest of the electricity sector.

Many of the IPPs in our sample display this disconnection from host market fundamentals. Enron's famous Dabhol plant is perhaps the most extreme example. For a that particularly needed additional peaking power, Dabhol offered a massive baseload facility. For an offtaker with annual revenues of roughly \$1.8 billion, Dabhol offered an 18% expansion of capacity at a price tag of almost \$1.3 billion—70% of total revenue. Dabhol was planned by looking to wildly exaggerate estimates for growth in demand; and project planners confused latent demand with the actual level of power consumption for which customers would

pay.⁶⁴ In Maharashtra during the development of Dabhol, electricity demand was projected to grow at 18% annually; in reality growth averaged 5.1%. Indeed, many countries in our sample—the Philippines, China, and India, to name a few—have a history of not meeting demand growth projections. Similarly, actual practice has often fallen far short of the expectation that retail tariffs would be raised to a level that recovered costs alongside the development of private power programs so that entire sector could arrive at a financial equilibrium. As prices have remained stubbornly low, the offtaker’s capacity to pay for new electricity consequently lagged.

This central role for price as a driver of outcome is qualified in several ways. First, across most of the countries (except India), the earliest IPPs tend to benefit from the longest periods of relative stability. This was the case in Poland, where Enron’s ENS operated as the country’s only greenfield IPP for several years—with relatively little scrutiny and comparison to other potential projects—before the Polish government began attempting to cancel the PPAs. In the Philippines, all of the early fast track projects operated for about a decade until broader troubles in the power sector caused politicians to look more closely at IPPs. Projects that entered in these early waves often could capture high risk-adjusted returns for many years before macroeconomic shock or political pressure began to erode their position.

Second, the commercial viability of projects is not a static concept. As a country’s IPP program develops, some IPP investors have adjusted their strategies—often shifting to wholly new technologies and contractual arrangements to remain competitively positioned. A striking example of this is Mirant’s portfolio of IPPs in the Philippines. The IPPs that were developed by CEPA/Mirant in the Philippines anticipated the evolution of the IPP program there. This portfolio has included nine plants at various times; here, however, we focus on just the five largest as detailed in Table 4, below:

TABLE 4: MIRANT’S MAJOR IPPS IN THE PHILIPPINES

| Plant | % Owned | Fuel | Capacity | Term | PPA/FIN/COD | Project Cost |
|---------------|--------------------|-------------|-----------------|-------------|--------------------|---------------------|
| Navotas I-III | 100% | Diesel | 210MW | 12 years | 1988/1991/1991 | \$40 million |
| Navotas IV | 100% | Diesel | 100MW | 12 years | 1992/1993/1994 | \$40 million |
| Pagbilao | 95% | Coal | 700MW | 29 years | 1991/1993/1996 | \$888 million |
| Sual | 92% | Coal | 1200MW | 25 years | 1994/1995/1999 | \$1,200 million |
| Ilijan | 20% | Nat'l Gas | 1200MW | 20 years | 1997/2000/2002 | \$960 million |

Note: PPA (signature of the power purchase agreement); FIN (financial closure); COD (commercial operations date—the onset of commercial operations)

The progression of these projects has anticipated the evolution of the Philippine generation market generally. The Navotas projects were intended to address the looming electricity crisis—the PPA terms were relatively short, and the fuel & technology choices reflected the need to build and operate the plants

⁶⁴ In the early years of the IPP boom (and still today), one hears the phrase, “no electricity is more expensive than the electricity you don’t have.” While true in an economic sense, this oft-quoted appeal to the opportunity cost of *not* investing obscured the commercial nature of the electricity market.

quickly. These diesel plants quickly became commercially obsolete when larger baseload coal and hydro IPPs entered the Luzon grid in the mid-1990s. As a result, the Navotas projects saw low utilization rates for the rest of the decade. While costly, these plants were seen by the Philippines government as essential to eliminating the power crisis and also as critical demonstration projects on the mechanisms for attracting private investment in the country.

Shortly thereafter, Pagbilao and Sual entered service, bringing availability payments for 1700MW of generating capacity. These plants led the way in diversifying the Philippine fuel base from expensive oil to coal—a move that likely prevented further major disruptions in the late 1990s when oil prices began to climb after a decade of declining prices. Later in the decade, Ilijan arrived on the scene, and while exacerbating the overcapacity that already existed on the Luzon grid, also demonstrates some of the benefits of long and stable experience with private power. A 2002 government review of the IPPs reviewed the project favorably on several fronts. Excluding fuel cost, the project was the 7th lowest cost IPP in levelized terms.⁶⁵ Ilijan was also one of the first plants to receive only a partial performance undertaking (under a 1995 government initiative to phase out the use of full guarantees), rather than the full PU that dominated during most of the 1990s.⁶⁶

In the renegotiations following the EPIRA review, Mirant was the first company to reach agreement with the government, and was one of the largest contributors to the net present value of the savings generated by the “renegotiations.”⁶⁷ The revenue loss from this agreement was not trivial—for example, Mirant’s SEC filings state that revenues at the Pagbilao station decreased by \$8 million in 2004 and an additional \$3 million in 2003 as a result of the agreement, and the overall net present value of Mirant’s contributions reached over \$165 million. However, the report continues to state that the settlement (which became effective in 2003) had no material financial impact on the contracts. The principal provision of the agreement had been a commitment by Mirant not to exercise its rights under a peculiar “overnomination” clause common in Philippine PPAs—this clause allowed a generator to nominate up to 105-110% of contracted capacity for the sake of calculating availability payments. This provision was intended to encourage investment in generation capacity, with the result that actual nameplate capacity of plants built was much larger than that originally contracted by the Philippines offtakers—an arrangement that made it difficult to plan and, not surprisingly, became unsustainable when developers made extensive use of the provision.

Notwithstanding these developments, Mirant’s Philippine assets appear to be quite profitable, generating revenues of roughly \$500 million annually from

⁶⁵ INTER-AGENCY COMMITTEE ON THE REVIEW OF THE 35 NPC-INDEPENDENT POWER PRODUCERS (IPP) CONTRACTS, FINAL REPORT (5 JULY, 2002).

⁶⁶ Kepco later paid an annual fee of \$800,000 to expand the coverage of this guarantee. *Id.*

⁶⁷ Mirant’s agreement with PSALM became effective in March 2003. Mirant Corporation, 2004 10-K at 16.

2002-2004.⁶⁸ Mirant has consistently ranked among the most profitable companies in the Philippines. In 2001 and 2002, Mirant was the top earning corporation in the country, and in 2003 Mirant subsidiaries accounted for three of the ten most profitable companies in the country. Both the Sual and the Pagbilao plants were criticized in the IAC Review for rapid payback periods, reflecting for example the fact that Pagbilao paid out 59% of the initial equity investment in its first four years of operations (1996-2000).

Third, when measuring cost it is important to examine the full range of benefits that the host was seeking when it created an IPP program. However, although host governments profess to weigh these benefits heavily, in reality projects that are not also highly competitive in terms of cost usually find their tariffs under pressure.

China, in its aggressive pursuit of foreign IPP investors was interested in attracting *foreign* capital and *foreign* technology, while protecting local markets. Thus, most foreign IPPs were not allowed access to debt from Chinese banks and were encouraged to bring in technology from abroad. In the early development of the Meizhouwan project, the developers were even told not to rely on local coal for the project, because that region of China was experiencing shortfalls in its coal supply at the time. The reasons justifying these choices faded once the immediate need was met and the cost of the arrangement became clear, to the detriment of foreign investors. In the Philippines, the large hydroelectric projects (CBK, Casecan, San Roque) have faced particularly harsh popular criticism and political treatment. Among other objections, each is criticized as being inordinately expensive—a fact that may result from the fact that electricity prices reflect a subsidy for irrigation water for surrounding communities.

Energy policymakers are often eager to involve IPPs in improving the fuel diversity of the electricity market. While IPPs can play a central role in introducing new fuels, in some of the most successful cases the new fuels were also highly competitive with incumbent power supplies. In the Philippines, the coal-fired IPPs that entered service in the late 1990s (including Pagbilao, Sual, and Quezon) filled an important need to diversify the fuel mix away from oil, but the costs of these plants also compared favorably within the overall electricity market, even while generating strong returns. In Mexico, the IPPs have largely spearheaded the introduction of natural gas into electricity generation. However, the Mexican government awarded all its IPPs through effective competitive bidding and offered secure repayment terms, which helped to secure competitive prices; in addition, new gas-fired capacity has allowed the country to retire old, dirty and inefficient plants—especially oil-fired plants that are costly—and thus avoided overcapacity and low dispatch that often obscures the potential efficiency of private generators. By contrast, in Brazil, the government desperately needed thermal plants in the late 1990s and offered generous incentives to developers to sink investment into thermal generation. When the country returned to normal

⁶⁸ See also, Mirant Corp. 10-K (2005) (“Our power generation businesses and our integrated utilities in the Philippines and Caribbean continue to provide consistent, stable gross margin and operating cash flows.”).

hydrological conditions, the special deals that had been put in place quickly unraveled. To remain sustainable, IPP developers have had to focus on how their projects compare to the cost and performance of the incumbent grid-connected system.

2. *Cost Disadvantages for Foreign Investors.*

Mindful of the importance of cost, we now focus on whether foreign investors may be at a permanent disadvantage when compared with local suppliers. A comparison of two projects in China—Intergen's Meizhouwan and CLP's Shandong Zhonghua—illustrates the higher costs that often accompany foreign investors. These two projects both had a large role for foreign participation but quite different management of foreign exposure and costs. Those differences, we argue, explain the difference in outcomes. Meizhouwan has stumbled in the face of aggressive pressure from the Fujian provincial government to lower its tariff. By contrast, Shandong Zhonghua seems to have weathered the widespread tariff reductions in relatively good shape.

Meizhouwan was a wholly foreign owned, foreign financed project with foreign coal imports coming from Indonesia, sponsored by Intergen, Lippo China Resources Ltd., and El Paso. The total cost for the 724MW project is estimated at \$755.2 million. Financing for the project came from a combination of international commercial banks, multilateral lenders (ADB), and foreign export credit agencies (COFACE). Under the original PPA, Meizhouwan was to provide electricity to Fujian for twenty years at a price of roughly RMB 0.517/kWh.

Shandong Zhonghua is a 3000MW coal fired project, developed jointly by China Light & Power of Honk Kong, Electricite de France, and two Chinese local government entities (Shandong Electric Power Corporation and Shandong International Trust & Investment Corporation). The entire project included brownfield investments (rehabilitation of two existing units) and also greenfield development of two new units. The \$2.2 billion financing for the project came largely from domestic Chinese banks and from the revenues earned by the brownfield assets.

Outcomes for these two projects have diverged in notable ways. Meizhouwan ran into trouble quickly; after its testing period in mid-2001, when the plant sold some power at low testing tariffs, the project company indicated its intention to declare commercial operations. According to project sponsors, local government officials refused to recognize COD, arguing that governmental approvals had not been met and raising technical questions regarding the units. From the project company's perspective, there was no mention of government approvals in either published regulations or the PPA, and technical requirements for COD had been met. Accordingly, they declared COD unilaterally and one of the units was shut down in late September by Fujian government officials until early 2002. Subsequently in June 2002, the project company missed the completion deadline and was technically in default; by September 2002, Meizhouwan was over \$20 million short in debt service due to non-payment by the local government offtaker.

Renegotiations produced an interim agreement in late 2002, including plans to apply an interim tariff of RMB 0.418 kWh while negotiating a permanent accord. The project was able to lower its costs by switching to domestic coal and by refinancing the foreign-denominated debt. In the meantime, Fujian's power surplus had eased and the project's electricity again became important to the government.⁶⁹ During the period of the power glut, the behavior of the Fujian government closely approximated that predicted by the theory of the obsolescing bargain.

In contrast, operations at Shandong Zhonghua have been relatively smooth. The brownfield units have operated as expected, producing revenues that helped finance the greenfield units that entered service in 2003 and 2004. All units have dispatched at high levels. No disputes or other problems have been reported publicly thus far. The province was able to absorb the incremental supply, which coincidentally came online during a period of strong economic growth in the province. By 2004, however, it appears as though results even for this project may be eroding—local officials in the annual tariff negotiations did not allow the project to recover the full costs of increased coal prices.⁷⁰

Several factors potentially differentiate Meizhouwan from Shandong. First, the average tariff for Shandong was only 10% higher than that of surrounding projects; the Meizhouwan premium, by some accounts, was 36.8% because it operated in a region dominated by hydro power that has intrinsically low variable costs. Second, the foreign Shandong sponsors likely set lower internal hurdle rates for their investment. Both CLP and EDF are national utilities that enjoy steady and healthy returns in their home market; both have viewed their foreign excursions as long term commitments (this is particularly true of CLP when investing in China). Third, Shandong was able to access inexpensive local inputs to a greater extent than Meizhouwan by relying on their local government partner. For example, Shandong was among very few foreign invested IPPs in China that obtained local RMB-denominated debt finance, which came at a lower cost and longer tenor than international finance for comparable Chinese projects at the time.

In the future, it does not appear that the cost disadvantages of foreign investors are likely to evaporate. The risk premium demanded by foreigners is likely to remain—especially where regulatory conditions are uncertain and arrangements for managing currency risks are poor. Access to local inputs and markets will remain limited. While in some cases, foreigners may overcome these obstacles through partnering arrangements (which we examine below), the role of the prominent industrialized nation utility company is dwindling in favor of domestic or regional companies. Many countries will likely be able to meet their investment needs from this pool, but many countries, particularly those that are least developed, will remain thirsty for electricity. For these countries, and

⁶⁹ However, there are concerns that the tariffs specified for the interim period may be further reduced. Even the management of Huaneng Power International (a national generation company) has cautioned that its plants in Fujian may receive tariff cuts of up to 10 percent in the near future. Pei Yee Woo, *supra* note 30, at 211.

⁷⁰ China Light & Power Annual Report (2005), at 26.

investors active in their markets, minimizing these cost differences or making sustainable decisions about how to manage them, will pose critical challenges.

3. *The Regulatory Challenge: Are IPPs too Expensive?*

More generically, questions have been raised about whether all private power—foreign and domestic—is too costly. The debate includes claims by government that private plants are laden with inflated risk premia and negotiated through corruption. The investors, for their part, argue that first-of-a-kind projects are often costly, and that state owned plants are inappropriate benchmarks. While evaluations of cost are, of course, different from project to project, the debate is often strikingly similar. In many countries, IPPs remain vulnerable to accusations of overpricing, with important consequences for the political and social sustainability of private power programs.

This debate is not easily resolved, even in particular cases. Hard comparisons of plant cost in the absence of standardized indicators (such as bids into a merit based system) are difficult to make in the absence of objective financial and performance data. Project costs for private developers reflect an array of site specific expenses that are difficult to compare. Investors also argue that their prices are affected government decisions in many fundamental ways including fuel and siting choice, and dispatch levels. In India, for example, a perceived surplus of naphtha led the government to encourage IPPs to use the fuel; a later decision to deregulate naphtha prices sent costs soaring. In turn, naphtha plants were dispatched for fewer hours, which afforded a lower base for amortizing capital costs. By contrast, state-owned power plants often operate on extremely loose terms relative to their private counterparts—with limited offtake requirements, flexible payment schedules, and often poor accounting of cost and revenue. Determining the cost benchmark for state owned plants is often impossible—indeed, many countries looked to IPPs as a potential means of introducing a competitive benchmark to the industry.

Often these disagreements are magnified by the lack of objective and transparent information and credible regulatory mechanisms. Conversely, mechanisms to share information and yield transparency have often mediated or averted disputes—allowing investors to reveal fuller information about costs and governments to avoid posturing that can make it impossible to adjust IPP arrangements in light of changing circumstances. In the Philippines, eleven contracts marked as problematic by the IAC Review committee (which did not consult or interact with the IPPs) were dismissed by PSALM (which did consult the IPPs and gained access to more detailed information on their financial status) as having no room to work on concessions. In India, investors report that at least one political review of IPP contracts dissipated once serious investigation began because government officials found nothing to address. In China, industry participants speculated that the equity participation of local government entities minimized distrust of the Shandong Zhonghua project and maximized distrust of the wholly-foreign owned Meizhouwan project.⁷¹

⁷¹ Pei Yee Woo, *supra* note 30, at 117.

To the extent that these observations are valid, the fundamental challenge to private investment in infrastructure is not simply one of costs and contracting, but also one of creating credible mechanisms for eliciting information and applying regulatory decisions. These challenges are hardly unique to the developing world. In the United States, the development of electric power markets was characterized by a similar pattern as now observed in developing countries. The terms of private concessions to private power companies were continually squeezed for value by public counterparties—either in signing new contracts, or even in changing the terms of existing contracts.⁷² Power companies saw their margins diminish; a stable equilibrium was attained only when independent regulators were established to oversee the market, allowing an acceptable return to investors while safeguarding the consumers' interests.

D. Understanding and Managing Political Risk.

1. *The Investor-Government Relationship.*

Fundamentally, all these projects face the risks that are typical of capital-intensive, long-lived investments—namely, they are in principle vulnerable to opportunistic government behavior. The relationship between investor and host, however, is not so simple. We have found three broad patterns that characterize the investor-government relationship for IPPs. In this section we examine those patterns; in the next section we explore how investors have attempted to manage the relationship in a way that reduces the risks of government opportunism.

First, the relationship between infrastructure investors and government is often characterized by overwhelmingly imperfect information. As discussed above, in many countries, there are vast differences of opinion regarding the cost and benefits of private plants—and how they compare with state-owned ventures or plants in other countries. Nor is there any agreement on how to make such comparisons.

Second, when governments have put pressure on contracts they have focused on identifiable weaknesses and points of leverage. Cases of outright repudiation of contracts are rare—the Dabhol case and the Tamil Nadu IPPs in India, Argentina's infrastructure contracts, perhaps some of the priority thermal plants in Brazil. More often, government pressure on IPPs focuses where the IPP arrangements are vulnerable—for example, during periods of spiking fuel prices or technical difficulty, or during the period prior to financial close or other events that lock in commitment with an increasingly wide array of actors.

Third, the outcome of government decision-making is not the outcome of a simple integrated process. In the Philippines, significant contributions to the concessions in the 2001 negotiations came from companies willing to make a deal—either because they had resources or (in the case of a project cancellation)

⁷² See George L. Priest, *The Origins of Utility Regulation and the "Theories of Regulation" Debate*, 36 J. OF LAW & ECON. 289 (1993).

because the company in question was also interested in exiting a project. In Andhra Pradesh, projects that had been tariff-bid at lower prices than the earlier fast track projects were pressured to renegotiate their tariff when the prices of naphtha began to rise, while a tariff-bid project that had already achieved financial close was excluded from this demand. The process is opportunistic as opposed to rational.

2. *Solutions?*

(a) Reliance on contracts.

In seeking to allocate risks in an efficient manner, the structure of classic private power projects loaded risk onto the contractual framework. Both investors and governments seemed comfortable operating within a world defined by the tightly worded provisions of a PPA or loan covenant. If the terms of the project were right, the deal would go through.⁷³ The success of this model was exaggerated, or perhaps evaluated prematurely, with the tendency of industry literature to proclaim “success” upon financial close.⁷⁴ If a deal secured financing, it was a good deal. In this environment, investors often failed to examine the world outside of the contract. At the same time, governments in many cases secured funds necessary to keep the lights on, and avoided the need for more meaningful reform.

This model meant that the turbulence of the late 1990s registered loudly on the increasingly complex contractual structures that had been loaded with risk. Contract instability was often seen by uncritical observers as evidence of failure; primed to expect governments to expropriate investments, observers interpreted contract stress as evidence of expropriation and assumed that stressed contracts would be broken. In fact, the pressure that came to bear on contracts during this period flowed from a variety of causes, and contractual protections have provided more traction than is commonly perceived.⁷⁵

Perhaps the most important case in this respect is the Philippines. In 2001, after several years of mounting pressure on the IPP contracts due (in part) to the progressive devaluation of the peso against the dollar-denominated IPP payments,

⁷³ See, e.g., Suman Babbar and John Schuster, *Power Project Finance: Experience in Developing Countries*, RMC Discussion Paper Series, No. 119, The World Bank (1998), at 10 (“As long as countries enable private project sponsors to sell power under long-term PPAs, countries do not have to make additional regulatory and market reforms to reduce the dominance of state-owned enterprises”); United States Agency for International Development, *Analysis of the Relationship Between Improved Energy Sector Governance and the Attraction of Foreign Direct Investment*, January 30, 2002 (finding that levels of greenfield investment in generation, distinct from other forms of power investment, demonstrated little correlation to improvements in electricity sector governance).

⁷⁴ For example, each of the most disastrous projects that litter the IPP field—including Enron’s Dabhol project in India, and National Power’s Hubco project in Pakistan—were awarded numerous accolades as “deal of the year” by industry publications upon securing financing.

⁷⁵ Broad evaluations of the utility of contracts in developing country infrastructure investment were quick to proclaim complete defeat in the aftermath of the crisis. See, e.g., Tom Marshella, *Debt Financing of Projects in Emerging Economies: Lessons from Asia*, 7 J. OF PROJ. FIN. 30, 31 (2001).

the Philippine Congress included in an electricity sector reform law a provision establishing a committee to review the IPP contracts for provisions that were “grossly disadvantageous, or onerous, to the Government.”⁷⁶ This committee produced a controversial report identifying twenty-nine projects with issues of various kinds, and handed their findings to the agency tasked with disposing of Napocor’s assets in the privatization process, PSALM, which was to implement the findings of the committee and to “diligently seek to reduce stranded costs, if any.”⁷⁷

Over two years, PSALM consulted with the IPPs to explore ways of reducing Napocor’s liabilities under the various contracts, eventually reaching agreement with eleven companies (responsible for eighteen projects) on adjustments that generated savings to the government of roughly US\$1 billion in net present value. In all but a few cases, the process was conducted in a cooperative manner without government threats of unilateral changes to the contracts. Project officials interviewed for this study often reported satisfaction with the process.

In Andhra Pradesh, the road has been more treacherous, but with outcomes that are worth noting. There, most of the projects have changed the terms of their original bargain under pressure from state entities. GVK Jegurupadu, a 214MW natural gas fired plant, and the first “fast track” project to reach commercial operations in India, was renegotiated twice before reaching commercial operations. These renegotiations addressed some issues of mutual concern, such as awkward provisions in the original contract, but also lowered the performance incentives that the plant was eligible to earn. However, since commercial operations in 1996, the PPA has been performed as expected, with timely payments from AP Transco.⁷⁸

The GVK story is amplified by the experience of a set of competitively bid projects that signed PPAs with the AP government utility (APSEB at the time; AP Transco today) in 1997 and were caught in the crosshairs of gas politics in India. As with many IPPs in India, these projects were designed to run on naphtha, with an anticipated shift to natural gas when expected gas fields came online. In 1998, naphtha prices were deregulated by the Indian government and rose sharply, which under the pass-through treatment for fuel prices in the Indian IPPs translated into a steep escalation of the cost of power from naphtha burning plants.

The PPAs for these plants included a condition requiring financial close occur by December 1998. Only one of the projects, Lanco Kondapalli, met this deadline. During this time, naphtha prices were rising steeply and gas allocations were failing to meet expected levels—a precarious position for IPPs that had not yet secured financing, yet had only naphtha as their fuel. Subsequently, these tariff-bid projects, with the exception of Lanco Kondapalli, were required to lower

⁷⁶ Republic Act No. 9136, § 68 (Phil.)(2001).

⁷⁷ Republic Act No. 9136, § 68 (Phil.)(2001).

⁷⁸ Currently there is another possible round of renegotiation—following a political review of the operating IPPs in Andhra Pradesh.

their tariff to equal the lowest fixed cost bid in the original tender in order to gain support for securing a scarce gas allocation,⁷⁹ and in 2005 none of these projects has reached commercial operations. Lanco Kondapalli, after lowering its tariff somewhat (although by far less than the other plants) and covering the cost of the conversion to natural gas, was commissioned in 2000 and has been performing under the PPA ever since.

What distinguished Lanco Kondapalli from the other tariff-bid projects? The AP government's reluctance to pressure Kondapalli seems to reflect both the fact that there was no clear means of handling the changing circumstances through the PPA contract, and Kondapalli was furthest down the path to commercial operation. The additional contractual layers that had accompanied Kondapalli's financial close and the start of construction had placed meaningful constraints on the government's ability to reduce the tariff. Instead, the government found leverage on the other three plants, which were in a weak position because they had failed to meet the contractual deadline and were facing an inability to get natural gas to fire their plants.

Even in settings that appear dismal for investors—such as the unfolding drama in the Indian state of Tamil Nadu—the fundamental power sales agreement provides some hope. The Tamil Nadu Electricity Board has maintained records of outstanding payments to the IPPs and has indicating its intention of covering these payments. These promises may, of course, prove to be illusory. However, the original power sales arrangements continue to frame the relationship between investor and government.

In nearly all the success stories for hosts and investors alike, adjustments to contractual terms have been necessary. In Thailand, according to industry participants, investors in the first IPP tender in 1994 gave little thought to the risk of currency devaluation, due to the fact that the baht had been credibly pegged to the dollar for several years. The projects weathered the financial crisis because of the government decision to allow the contracts to be adjusted for dollar-indexed payments. However, the outcome would have been far worse had the government decided to take a harder line—barring the adjustment of contracts—as most of the investors would have simply lost their development costs and gone home, unable to secure financing in the post-crisis environment.

GVK in Andhra Pradesh and Quezon Power in the Philippines, both successful projects, have each been renegotiated several times. The occasions for these renegotiations often were not pleasant, but the ensuing agreements often resolved awkward arrangements in the original contracts. In Quezon, for example, the original agreement called for Meralco to purchase all of Quezon's contracted output on a take-or-pay basis, whether or not that output was actually available. When the plant suffered from low availability in the early years of operations, Meralco grew increasingly frustrated, eventually precipitating a

⁷⁹ This was Gautami Power's fixed cost bid of \$0.06/kWh (foreign exchange component) and 0.69 rupees/kWh (local currency component). This account, repeated in several forms by industry participants in Hyderabad, is recounted on the website of the Andhra Pradesh government, at <http://www.aponline.gov.in>.

renegotiation by withholding payment. In the outcome, however, the parties agreed to limit capacity payments to the actual rated capacity, stiffen the penalty for not meeting contracted availability (both of which were important to Meralco), and to clarify the application of the take-or-pay terms to specify that Meralco must take all contracted energy that is available from Quezon.

The global IPP experience is no doubt littered with such experiences, from both successful and unsuccessful projects. The examples in this brief discussion serve to illuminate the fact that many problems that IPPs encountered in the 1990s reflect growing pains in a new and rapidly growing market, rather than fundamental propensity for host countries to expropriate investments or fundamental weaknesses in the potential for private investment in power generation itself.

(b) Local partners.

Among the most prominent strategies employed by investors operating in a foreign environment is reliance on partnership with local actors. This is seen as a way to facilitate communicating and operating in a foreign environment; it is also prized as a way to mitigate the political risks inherent in being a foreigner. The need to manage these risks is particularly acute when, as in electric power, the investment is prone to a high degree of politicization.

The traditional “political insider” partner—a partner whose connections are so omnipotent that they can fix all problems—has been rare in the IPP experience. Almost all of the Indonesian IPPs had as a partner a member or associate of the Suharto family, and with the end of the Suharto regime shortly after the financial crisis washed over Indonesia, the new government faced decisions about private infrastructure contracts that were becoming increasingly expensive as the local currency plummeted. In addition to addressing the cost of the projects, the new administration under President Habibie, set up a commission to investigate allegations of corruption (under its now famous Indonesian acronym, “KKN”). Popular suspicion of corruption in the IPP sector was thick, and although no allegations were ever proven (to our knowledge), the close family ties and non-transparent bidding process for the projects left the IPPs very little leverage in the public eye, while bolstering the position of politicians eager to assume a hard stance. The political insider partners acquired by IPPs were essential when Suharto ruled but quickly became liabilities when the political leadership changed.

The Malaysian IPP sector is sometimes seen as having investments that are politically allocated. However, there are important differences contributing to the relatively positive outcomes in Malaysia. First, the domestic businesses that dominated the IPP sector in Malaysia were all legitimate companies (although not always in the electricity sector—Genting Berhad, which has continued its IPP investments, was originally a gaming concern). Second, the Malaysian IPP sector was nearly entirely a Malaysian enterprise—with local investors, local capital, local fuel and mostly local construction. When Tenaga came under pressure in the aftermath of the financial crisis, there were rumblings about the need to address the “expensive” IPP contracts. Available evidence suggests that, in fact, no action

was taken to alter the terms of the original deals, or if it was, the process was handled behind closed doors.

The ingredients of classic insider governance in the Malaysian sector were all present. First, the government was a controlling shareholder in the publicly listed Tenaga—it appointed the Tenaga board and had final authority over any significant corporate decisions. Second, Tenaga itself held a 10-20% stake in most of the IPPs when most of the post-Asian crisis action occurred. Third, the principal lenders to the IPPs were state controlled—most of the banks lending to the projects were state banks, while the largest (and sometimes the only) bondholder providing funds to the IPPs was the state pension fund. Finally, most of the IPP deals had been led by investors with close ties to the Malaysian government—long term relationships, both within and without the IPP sector, were on the line. Everything we know suggests that the Malaysian IPPs have fared just fine since the crisis.⁸⁰

More common than the “political insider” are partnerships with domestic private companies. In fact, in the sample of countries and projects that we have reviewed, it is difficult to find examples of successful projects that do not have a local partner. These partnerships focus on supporting the operations of the project, such as by navigating local input markets or by managing relationships with employees and government officials. These benefits are subtle, and often difficult to evaluate without in-depth treatment on a case-by-case basis.

The Shandong Zhonghua project in China, discussed earlier, was able to access low cost local input markets in a way impossible for wholly foreign IPPs in China by working through their local partner. Investors in Poland have avoided some coal-fired plants in which the labor force was unionized, to avoid tangling with the powerful coal unions. Investors involved in the 478MW natural gas-fired Trakya Elektrik project in Turkey have reported productive results from their partnership with Turkish construction conglomerate Gama. The principal benefits identified in all positive evaluations of local partners have been relatively unexciting—arranging meetings, identifying appropriate contacts, explaining local business or government practice, managing relations with employees or state officials. Notably, we have encountered no cases where the local partner deployed political resources to resist government pressure or other classic political risk.

The principal costs of all local partner arrangements flow from the fact that such arrangements often generate new risks in project governance because the norms of the local partner can differ from those of the foreign investor, and it can be difficult for the outside investor to police the behavior of its partner. With the exception of China, most of the poor experiences in local partnering have come in projects in which the local partner was the majority stakeholder, and controlled the project company—perhaps reflecting the governance challenges when interests diverge.

⁸⁰ Jeff Rector, *The IPP Investment Experience in Malaysia*, at 12-14 (draft working paper on file with PESD)(June 2005).

In some cases, such arrangements have allowed local partners to conceal poor management, such as in the case of Spectrum Power in Andhra Pradesh. The 200MW Spectrum Power project was one of the original “fast-track” projects in India and was developed by a non-resident Indian engineer and an associated firm from Hyderabad. Problems began when the project’s foreign sponsor and minority shareholder, in the course of a dispute with the local partner, discovered that project costs had exceeded projections by 30%. Fueled by this discovery, the dispute escalated with the detection of cost irregularities in the development and construction of the plant, which involved the project’s lenders in investigating the situation. Concerned by allegations of fraud against the local partner, and delicate financial health of the plant due to mismanagement, the lenders eventually declared an event of default and assumed control of the project in 2001. The government of Andhra Pradesh has since moved to file criminal charges against the local promoter, alleging fraud in the management of the contract.

While this story is largely driven by the poor selection of the local partner, the project was also structured in a way that allowed these problems to escape detection. For example, the loan documentation has no trust and retention agreement to govern the handling of project revenues—the foreign partner and even the local banks had to physically investigate irregularities that would have otherwise been more readily apparent. Additionally, unlike other fast-track projects in India, Spectrum did not apply for a counter-guarantee from the government of India. After the GOI’s first counterguarantee—for Enron’s Dabhol project—generated such controversy, the process of obtaining such guarantees became extremely arduous. Spectrum’s primary lenders, the State Bank of India, did not require the counter-guarantee, and Rolls-Royce (the EPC contractor for the project) had coverage from the British export-credit agency. Without additional scrutiny, the project rolled forward with little check from authorities (the Government of India) that otherwise would have had a strong incentive to help police the partner’s behavior.

In other cases, the local partner proves unwilling or unable to deliver the types of benefits the foreigner expects. Local investors have long term and diverse interests in the host country, interests that often constrain zealous insistence on contract terms in one. The extreme example of this is seen in the Pillai Perumal Nallur (“PPN”) project in Tamil Nadu, a 330MW project firing on naphtha with a planned transition to natural gas. PPN Power Generating Company was promoted by local partner Apollo Infrastructure Projects Finance, which held a 28 percent equity stake. The project’s other equity partners are Marubeni, the equipment supplier (26 percent), El Paso Energy (26 percent) and PSEG (20 percent).

The PPN project, which commenced operation in April 2001, is a 330 MW combined-cycle plant, designed as a baseload facility selling exclusively to TNEB under a 30-year PPA. PPN originally fired on naphtha, provided under a long-term fuel supply agreement with the state-owned Indian Oil Corporation. The project later switched to a combination of naphtha and natural gas based on a gas allocation for 60 percent of its capacity. The project expected to obtain a full gas allocation from GAIL before the end of 2003, but is now seeking to close a deal

with the private Hindustan Oil Exploration Company, Ltd., for gas from the offshore PY-1 field.

In 2001, TNEB announced a decision to pay its five IPPs only 2.25 rupees per kWh—a figure obtained by reference to the amount of cost recovered by TNEB in its electricity sales. After this notification, TNEB failed to pay even this amount to PPN, and the plant was shut down as the project defaulted on its Q1 2003 debt repayment obligation of Rs 5 billion (approximately US\$107 million), and lacked money to buy fuel due to the TNEB's payment failure.

In response, PSEG and El Paso sought to have PPN Power Co. file an arbitration claim against the Tamil Nadu state government. This effort was blocked by the local partner, who enjoyed the cooperation of the other foreign investor (Marubeni), in helping defeat the proposed board resolution for arbitration by a vote of 8 to 5. Instead, PSEG Global and El Paso initiated arbitration proceedings on their own behalf before the International Court of Arbitral Tribunal seeking to recover Rs 4.69 billion (approximately US\$100 million) owed to the project by the TNEB. The project is now embroiled in controversy as the project company filed anti-arbitration suits against El Paso and PSEG in Indian court. Overdue receivables from TNEB to the project as of December 21, 2002 were \$36 million⁸¹ and by 2004 had reached \$110 million. In 2005, El Paso sold its stake in PPN for \$20 million—a poor return on an original investment of \$41 million.⁸²

(c) Prominent victims (multilateral and foreign official partners).

The other principal partnership strategy employed by private investors, particularly foreign private investors, is to involve a prominent multilateral or foreign public entity in a project, with the goal of deterring adverse host government action for fear of stepping on big toes. The information necessary to investigate the scope and effectiveness of this strategy is almost impossible to obtain in a systemic and public form.⁸³ This is due primarily to the incentives of the parties involved. Governments do not want to admit acquiescing to pressure from such entities, while multilateral or foreign government entities do not want to appear to be bullying sovereign counterparts.

In the IPP experience, we have encountered mixed evidence regarding the effectiveness of this tool. These actors seem to be most effective when given clear boundaries to enforce—such as preventing outright expropriation, recovering a paid insurance claim, or protecting debt payments.

Several projects with involvement of multilateral or foreign government agencies have nonetheless suffered severe host country troubles. Meizhouwan

⁸¹ El Paso Corporation, Form 10-K, at 150 (2003).

⁸² El Paso Corporation, Form 10-K, at 63 (2005).

⁸³ In one starting point, the World Bank notes that MIGA has issued 72 guarantees to 39 electricity investments, 32 of which were in the generation sector. Of this number, one claim has been paid (\$15 million for a project in Indonesia) and five disputes have been “mediated.” World Bank, *supra* note 3, at 23-25.

enjoyed support from the ADB and from the United States Export-Import Bank (“US Exim”). Dabhol secured substantial financing from US Exim. GVK had the IFC as lender and equity holder. Quezon had substantial lending from US Exim. Hubco in Pakistan enjoyed substantial World Bank support, and many of the greenfield projects in Argentina included substantial support from multilaterals or export-credit agencies.

The involvement of prominent actors on the international stage as a tool for political risk mitigation seems primarily a blunt instrument—useful, at times, for staving off disaster and for protecting debt coverage. Equity seems relatively exposed, even with participation from prominent partners; such partners appear to offer little cover in the several projects that have seen equity investors’ returns whittled away through a series of smaller disputes more akin to “creeping expropriation” than to the rare instance of unrestrained aggression.

This weak influence of prominent partners is likely due to two primary factors. First, multilateral and foreign government agencies are almost always lenders or guarantors of projects—rarely equity holders in any significant way. Thus, their self-interest is limited to debt service or to events in which a guarantee is called. In the IPP universe both payment default on loans and events triggering a guarantee have been quite rare. Second, multilateral organizations are not free to use their influence because they must be attentive to their other relationships. Multilateral banks must sustain their broader relationship with a host government. Foreign ECAs are primarily interested in facilitating the business of their home country exporters, which are not always identical to serving the equity holders in a project; equipment suppliers are usually paid more quickly, and exit with their profit intact.

(d) Legal recourse: litigation and international arbitration.

This study has not focused on experience of legal workouts in the IPP arena. First, this is because reaching arbitration or insolvency already connotes a dismal outcome in itself. Perhaps this is why, despite widespread trouble in the IPP sector, only relatively few have sought recourse through international arbitration. Second, the value of legal proceedings is something of a moving target; numerous arbitral proceedings are ongoing, including parts of the Dabhol case in India, two of El Paso’s projects in Brazil, and all of the claims flowing from Argentina.

However, experience to date suggests that few investors or governments have gained much from arbitration. Investors, who so far as we know have not lost a single arbitral claim, commonly face anti-arbitral injunctions in the host country prior the proceeding and costly enforcement battles afterwards. Governments, for their part, face enormous claims for amounts that, in some cases (e.g., Dabhol) include the full discounted value of revenues for the project over its lifetime—an aggressive application of common law principles governing the award of expectation damages, and one that may encourage some of the extreme resistance to arbitral awards that the industry has seen.

Some cases of domestic judicial repudiation of arbitration clauses or judgments are clearly egregious—including the kidnapping of an Indonesian arbitrator in the Karaha Bodas case, and the three page opinion in the Pakistani litigation that granted an anti-arbitration injunction against the sponsors of the Hub River project. However, running through many of these cases is a profound disagreement regarding legal principles of hardship, changed circumstance, and economic force majeure. In the major cases that have flowed from instances of macroeconomic shock, consideration of these principles is obscured by the fact that the defendants in those claims—Indonesia and Argentina—failed to even negotiate in good faith.⁸⁴

VI. VISIONS FOR THE FUTURE: IMPLICATIONS FOR PRIVATE INVESTMENT IN POWER.

The world for private investment in power generation has changed. While the long-term PPA is not a thing of the past, the pure single-buyer model of the 1990s may have run its course. Several countries in our limited sample, including Malaysia, Thailand, Kenya, and Mexico, will continue to rely on IPPs with long term contracts for a substantial part of their power supplies. However, governments are increasingly unwilling to provide the comfort that was available in the 1990s round of power projects.⁸⁵ Governments have been particularly averse to the extension of sovereign guarantees and to the assumption of foreign exchange risk through hard currency denomination or indexing. In other cases, such as Brazil and the Philippines, the process of broader power sector reform is continuing, with potentially large risks for private investors. All these situations raise uncertainty and elevate risk premia (and costs), which could make the traditional IPP model additionally unattractive for investors and hosts alike.

The first round of IPPs arose in markets where demand for power was rising more rapidly than state-owned generators could deliver supply. These countries relied mainly on foreign investors for IPPs, although in a few cases (notably China and Malaysia) local private (or quasi-private) investors played a central role.

In some of the countries in this initial set, there has been a large increase in domestic finance for electricity—including China and Thailand. These countries, now, face little pressure to attract foreign capital and technology. To the extent that these power systems can remain largely closed to private foreign investment, they are unlikely to be sites for major foreign IPP investments. However, these countries could generate vibrant domestic IPP investments.

⁸⁴ This was noted explicitly by the tribunal in the Himpurna case. *See* Final Award of 4 May 1999 Himpurna California Energy Ltd. (Bermuda) v. PT (Persero) Perusahaan Listrik Negara (Indonesia), 14 Mealy's International Arbitration Reports, at A-1 to A-58. By contrast, it seems a likely factor in the Argentina cases, which remain pending—the most advanced being a claim by CMS Energy concerning its investment in a gas transmission network. *See* CMS Gas Transmission Company v. Argentine Republic (Case No. ARB/01/08).

⁸⁵ At the far end of the spectrum, Kenya is considering the use of guarantees in future IPP arrangements in order to lower prices.

Many other countries—including the Philippines, Egypt, Kenya, and others—continue to face the need to attract investment from abroad. In the absence of the highly liquid markets in the industrialized countries that fueled much of the 1990s boom, a premium will be placed on these countries' ability to provide an investment environment that will attract scarce capital.

The next wave of IPP investment is likely to be dominated by two main types of actors. The first is the foreign IPP investor. These investors are already familiar in today's IPP market, although the exact identities of these firms has shifted a bit—especially in the wake of the troubles in the sector during the late 1990s.

The second type of IPP investor is a less familiar actor. In place of the American and European firms that have dominated the IPP market, a host of domestic and regional firms from the developing world are taking their place. These new actors are firms that are comfortable operating in power sectors that are a hybrid of the previous state system and the new more market-oriented systems. They rely on local knowledge and domestic capital; by contrast, the normal foreign IPP relies on expertise in global technology and access to global financing.

It is too early to determine whether these new actors—what we have elsewhere called “dual firms”—will create an uneven playing field that would chill participation by conventional private investors (notably foreign investors). The example of Thailand, grappling with the increasing participation by state-dominated firms in the electricity sector, suggests that the field will be tilted to favor such firms. Moreover, the emergence of these firms may also delay broader reforms, such as tariff rationalization and collection—indeed, firms that thrive in this market often do so precisely because they are comfortable with the risk implied by this mismatch.

This suggests that both the main actors in the IPP market are likely to bring with them some attributes that lead to unsustainable patterns of investment. The “shock therapy” of foreign investment, as practiced in much of the 1990s, involved high risk premiums and high-strung contracts—an arrangement that, where costly and inflexible, has not performed well. At the same time, the well-connected dual firms that have access to cheaper capital seem likely to yield distorted markets in which normal private actors, including foreign firms, are unable to compete.

We now explore the possible elements of a new model by identifying several shortcomings of the existing model and remedies that could apply.

A. Elements of a New Model?

We are still in the early stages of assembling the implications of this study for the next wave of investment, but so far we have identified a few important elements.

Improved transparency and regulatory capacity.

Earlier in this paper, we argued that one of the critical roles of regulation has historically been to protect utility investors against inevitable political pressure. Most directly, regulators that exercise robust jurisdiction over the electricity sector can effectively insulate energy market participants. More importantly for our purposes, however, is to observe the key role that regulators can play in resolving the information problem in a long term-regulated investment, by signaling publicly a fair allocation of costs and benefits.

Where it has proved too difficult to establish a credible regulatory body then alternative mechanisms are needed to assure public credibility. This can be accomplished in several ways, ideally in combination. On the investor side, serious thought may be given to ways in which to increase the amount and transparency of information available to government counterparties or to the public. On the government side, reformers may (in addition to pursuing traditional reform activities), promulgate a framework for evaluating the costs of state owned generation, the intended goals of inviting private power projects, and how to evaluate private sector participation within the power sector as a whole. Both sides can work together in the project development process to incorporate these principles into the contractual obligations for specific projects.

Where institutions are weak and dispersed, establish centralized entities that act as the legal and financial counterparty for private investors.

A recent joint study by the Asian Development Bank, Japan Bank for International Cooperation, and the World Bank, reviewing the record of infrastructure investment in Asia, found that (among other things) “the center matters.”⁸⁶ The almost inherent instability of IPP programs, when inserted to an unreformed electricity sector, means that investors rely largely on the governance capacity of local institutions. In many countries, this capacity grows thin with distance from central government institutions. Additionally, incentives shift as sub-national actors respond to local, rather than national, concerns.

This trend is echoed in the IPP experience, both in countries that share authority over electricity between national and subnational actors (India and China) and in countries that have both types of arrangements (the Philippines). The success or failure of India and China in centralizing the IPP relationship may point the way for countries with similarly complex governance characteristics. Countries that lack, or for other reasons wish to avoid a national utility or single buyer model, marketing and sales arrangements such as these may offer added stability and the opportunity to simplify the management of delicate reforms.

Insist on commercial viability, but set modest goals in areas other than price.

A clear, and presumably uncontroversial, lesson from earlier power investment is that price is critical driver of outcomes for IPPs. Following this

⁸⁶ Asian Development Bank, Japan Bank for International Cooperation, World Bank, *Connecting East Asia: A New Framework for Infrastructure* (2005).

point, policymakers and investors should set modest goals for private power projects in areas other than strict commercial viability. IPPs that have led the charge in other areas of development in the electricity sector have almost universally fared poorly. Prominent among these are the thermal projects in Brazil, most of the (hypothetically) natural gas-fired projects in India, and the rare wholly foreign ventures in China.

More Sophisticated Risk Management

It is not practical for investors in most markets to shift the full weight of market and political risk to the government. In the 1990s, risk was often allocated in undivided chunks—100% denomination of payments in US dollars, or 100% of the market risk allocated to government. Many of these risks proved to be unmanageable, or if so, then only with considerable pain. As the decade proceeded, risk was increasingly allocated in smaller bits and pieces—partial guarantees, private fuel obligations, tailored indexation mechanisms. How far can this model be taken? As we have seen, governments have grown wary of accepting those full liabilities, and even where they have accepted them in contracts often such provisions do not hold. Provisions that align incentives more precisely with control over risks could be more productive. For example, project operators whose fixed assets make themselves vulnerable to being squeezed could establish fuel subordination agreements that make part of the fuel payments contingent on maintaining project revenue.⁸⁷

Contracting for flexibility.

Much ink has been spilled on the need to include flexible terms into long term contract arrangements such as PPAs.⁸⁸ However, the marketability of such arrangements has remained suspect, and few concrete proposals have been put forward. The IPP experience that we have observed suggests two areas, in particular, where flexibility may be possible and quite useful in yielding better project outcomes.

First, the most common area that developers have turned to when under pressure to lower prices is the reduction of pass through elements—notably by altering fuel contracts or by refinancing with local or lower-interest debt. However, there appears to be some disagreement regarding how this is to be handled. Some investors expected that among the benefits of long term sales contracts, they would be able to capture the profits of these types of cost-reducing moves, while governments reasonably note that elements outside of the control of investors should be passed on to consumers. Clarifying the terms according to which these benefits are to be divided promises to smooth the renegotiation process in many cases.

⁸⁷ Wigmore, Gary S. and Susan E. Turner, *The Disappearing PPA: Moving to Merchant Power in Asia*, 19 J. OF ENERGY & NAT'L RES. L. 72 (2001).

⁸⁸ See, e.g., Jeswald Salacuse, *Renegotiating International Project Agreements*, 24 FORD. INT'L L.J. 1319 (2001).

Second, the experience in the Philippines as it limited payments from the peculiar overnomination clause in the PPAs offers a model for explicitly identifying the revenue streams that would be flexible during a renegotiation and the circumstances under which these can be adjusted. Many projects have included ways to make “extra” revenue through PLF incentives or other avenues—these revenues could provide a cushion for specific time so difficulty.

VII. CONCLUSION.

Meeting the electricity needs of developing countries in the coming few decades will require several trillion dollars of investment. Although governments and multilateral institutions have rekindled their interest in official lending for infrastructure in some cases, the provision of infrastructure will require substantial private involvement. As the dust settles on the first round of investment, both governments and investors look back with mixed feelings, even while gearing up for another round of investment in the near term.

In this study we evaluate whether IPPs have met the reasonable expectations of key stakeholders—notably investors and host governments. Generally, we find that IPPs have met reasonable expectations of host governments where the scope of the program was limited, where care was taken to solicit competitive investment, and where the country can marshal the resources from consumers or from taxpayers to afford private power.

However, many countries have not followed this path, and have extracted less value from the IPP experience. Often this was the result when an IPP program was implemented in response to crisis, or when private investors built generators but government did not implement the reforms necessary to allow the electricity sector as a whole to cover its full costs.

For investors, the IPP experience has been similarly mixed. Poor outcomes, in general, have been precipitated by either macroeconomic shock. In a few countries, other identifiable factors have played a major role—such as amorphous legal standards in China or corruption in Indonesia. Even when confronted with macroeconomic shock, a striking number of projects have managed to weather the storm.

Some of the challenges that characterized the first round of IPP investment—poorly structured projects, uncritical acceptance of the credibility of a host country’s commitment to private infrastructure investors, or inattention to an offtaker’s real ability to pay—may be corrected in the next round. Our study has begun to identify a handful of factors that could (and should) play a major role in the next round; an ongoing task that will be the central focus in the final months of the study. This new round of investment will arrive with a new generation of lawyers, bankers, and developers ready to solve the challenges of the past with new contracts and new financial engineering techniques. It is crucial to focus on the sources of trouble and opportunity from the 1990s, lest the next wave repeat the same mistakes of the past.

Electricity Market Context for IPP Investment

| Country (# IPPs) Year of first IPP | Generation Year Opened | Electricity market context ... |
|---------------------------------------|---------------------------|--|
| Argentina (16+) 1992 | 1992 | IPPs developed in privatized electricity market, selling in highly competitive contract and spot markets. |
| Brazil | 1995 | IPPs developed in partially private electricity market, selling to distribution companies and large users. |
| China (32) 1985 | 1985 | IPPs developed in reforming electricity market, selling to provincial power authorities. |
| Egypt (3) 1998 | 1996 | IPPs developed in unreformed electricity market, selling to vertically integrated national utility holding company. |
| India (16) 1991 | 1991 | IPPs developed in reforming electricity market, selling to state electricity boards. |
| Kenya (4) ⁸⁹ 1996 | 1996 | IPPs developed largely unreformed electricity market, selling to state transmission and generation monopoly. |
| Malaysia (13) 1993 | 1993 | IPPs developed in unreformed electricity market, selling to vertically integrated national utility. |
| Mexico (16) 1995 | 1992 ⁹⁰ | IPPs developed in unreformed electricity market, selling to vertically integrated national utility. |
| Philippines (45) 1988 | 1988 | IPPs developed in unreformed electricity market, selling to national generation and transmission utility. |
| Poland (3) 1997 | 1997 | IPPs developed in reforming electricity market, selling to a national grid operator; ongoing reform has led to stranded cost problems. |
| Thailand (7) 1997 | 1994 | IPPs developed in unreformed electricity market, selling to national generation and transmission utility. |
| Turkey (9) 1994 | 1984 ⁹¹ | IPPs developed in unreformed electricity market, selling to national utility. |

“Year of first IPP” refers to the date when the PPA or other fundamental agreement was signed.

“Generation opened” refers to the year in which private investment in electricity generation was authorized.

⁸⁹ There were also 3 privately “emergency” plants (totaling 105MW) that were funded primarily via World Bank loans and signed one-year contracts to help alleviate pressure from a drought on Kenya’s hydro dependent electricity sector. These projects are often referred to as “IPPs”; we exclude them from consideration for being distinct in size, duration of contract, financing and purpose, from other IPPs (even within Kenya).

⁹⁰ In Mexico, there were several cancelled projects based on flimsy legal foundations beginning in 1990. The reforms in 1992 established the legal basis for all of the operating IPPs in Mexico.

⁹¹ Turkey passed its 1st IPP Framework in 1984, which was unsuccessful in attracting any investment at all. In 1994, Turkey passed the 2nd IPP Framework, which led quickly to the first IPPs.

PESD IPP Study: Project Sample

| Project Name | Country | Fuel | Capacity | Main Sponsors |
|--------------------------|----------|-------------|----------|----------------------------|
| <i>Macaé</i> | Brazil | Nat'l Gas | 928MW | El Paso |
| <i>Shajiao C</i> | China | Coal | 1980MW | CEPA • Mirant |
| <i>Meizhouwan</i> | China | Coal | 724MW | Intergen, El Paso, Lippo |
| <i>Shandong Zhonghua</i> | China | Coal | 3000MW | CLP, EDF |
| <i>Sidi Krir</i> | Egypt | Nat'l Gas | 685MW | Intergen |
| <i>Suez</i> | Egypt | Nat'l Gas | 683MW | EDF |
| <i>Port Said</i> | Egypt | Nat'l Gas | 683MW | EDF |
| <i>GVK Jegurupadu</i> | India | Nat'l Gas | 216MW | GVK, CMS |
| <i>Spectrum Power</i> | India | Nat'l Gas | 208MW | Spectrum Power |
| <i>Lanco Kondapalli</i> | India | Nat'l Gas | 250MW | Lanco, CDC Globeleq |
| <i>Dabhol Power Co.</i> | India | Naphtha/Gas | 740MW | Enron, Bechtel, GE Capital |
| <i>Essar Power</i> | India | Naphtha/Gas | 515MW | Essar Steel |
| <i>CLP Paguthan</i> | India | Naphtha/Gas | 655MW | Powergen • CLP |
| PPN | India | Naphtha/Gas | 330MW | El Paso, PSEG, Marubeni |
| Samalpatti | India | Heavy Oil | 106MW | Covanta |
| Madurai | India | Heavy Oil | 106MW | Covanta |
| ST-CMS | India | Coal | 250MW | CMS |
| <i>IberAfrica</i> | Kenya | Diesel | 44MW | Union Fenosa |
| <i>Tsavo</i> | Kenya | Diesel | 75MW | Cinergy, CDC |
| <i>OrPower4</i> | Kenya | Geothermal | 48MW | Ormat |
| Monterrey III | Mexico | Nat'l Gas | 570MW | Iberdrola |
| Rio Bravo II | Mexico | Nat'l Gas | 568MW | EDF |
| Merida III | Mexico | Nat'l Gas | 530MW | AES |
| Navotas I and IV | Phil. | Diesel | 310MW | CEPA • Mirant |
| <i>Pagbilao</i> | Phil. | Coal | 700MW | CEPA • Mirant |
| <i>Quezon</i> | Phil. | Coal | 460MW | Intergen, Ogden, PMR |
| <i>Magellan</i> | Phil. | Diesel | 58MW | Edison Mission • Covanta |
| <i>Casecnan</i> | Phil. | Hydro | 140MW | CalEnergy |
| CBK | Phil. | Hydro | 640MW | Edison Mission, IMPSA |
| <i>Cavite</i> | Phil. | Diesel | 63MW | CMS • Covanta |
| ENS | Poland | Nat'l Gas | 116MW | Enron (Prisma) |
| Eastern Power | Thailand | Nat'l Gas | 350MW | GMR Power |
| Gebze, Adapazari, Izmir | Turkey | Nat'l Gas | 3860MW | Intergen |
| Iskenderun Enerji | Turkey | Coal | 1300MW | Steag |
| <i>Trakya Elektrik</i> | Turkey | Nat'l Gas | 478MW | Enron (Prisma) |

The projects listed here represent the projects primarily relied upon in drawing the conclusions presented in this paper. Names listed in *italics* represent projects for which in-depth work has been done, including any of: (1) country and/or plant visits, (2) stakeholder interviews, and in some cases (3) full case studies on the project. For some countries—such as Thailand and Mexico—our research has suggested that the IPP experience is primarily driven by country and sector level characteristics. Individual projects in those countries are listed primarily as examples of the country level experience and have been the subject of brief reviews that are reported in each country study.

Selected Experience with IPPs: A Review of Thirteen Countries

The classic IPP model—that of a privately developed power plant selling electricity under long term contract to a single national utility—took root primarily in South-East Asia. However, in all more than fifty countries experimented with variations on the IPP model, with details tailored to meet the unique characteristics of the power market in each country.

Our final case selection includes: Argentina, Brazil, China, Egypt, India, Kenya, Malaysia, Mexico, the Philippines, Poland, Tanzania, Thailand and Turkey. Details on the process of case selection is discussed in the research protocol for the IPP study, “The Experience with Independent Power Projects (IPPs) in Developing Countries: Introduction and Case Study Methods,” available at <http://pesd.stanford.edu/publications/20528/>.

This Annex details briefly the IPP experience across these countries. (*Tanzania, Brazil, and Argentina are still in process—we comment where appropriate on these cases*).

The Philippines entered the IPP market early, with a 1988 presidential decree authorizing private investment in the generation sector. Major investment in IPPs here occurred in response to a 1991-93 electricity crisis that saw rolling blackouts of 12-14 hours per day, up to 300 days per year. The 40+ IPPs that were developed in the Philippines proceeded in three broad stages: first, a series of “crisis” plants with shorter (5-12 year) contracts and usually fired on oil or diesel; second, a group of big baseload coal plants with longer (20-25 year) contracts; and finally, a series of natural gas-fired and hydro plants that reached operations between 1998 and 2001. The major hurdle in the sector came with the Asian financial crisis, which precipitated (among other troubles) high electricity prices, deteriorating fiscal stability in the national books, and public dissatisfaction that often focused on the IPPs whose contracts stood out in sharp relief against the hidden subsidies and soft budgets of the state dominated system. In 2001-02, in response to these public concerns, a government committee was appointed to review the IPP contracts. A widely publicized renegotiation effort followed, however, our research indicates that contracts were widely honored in this process and investors remain largely pleased with their experience in the country.

Malaysia moved into the market shortly after the Philippines, following mounting troubles in its electric power utility in the early 1990s. The 13+ Malaysian IPPs, which were predominantly large natural gas-fired projects, sold their output under long term ringgit-denominated contracts to Tenaga Nasional Berhad, the national utility. Most of the projects were arranged in a round of investment during 1993-94, and were not competitively bid, but rather negotiated directly, resulting in higher tariffs than Thailand’s competitive projects, and handsome profits for the sponsors. Unlike most other countries, which involved substantial participation from US and European utilities, the project developers in Malaysia were exclusively Malaysian firms, while capital was sourced almost

entirely from domestic markets, including state pension funds and other institutional investors. The Malaysian IPPs faced pressure during the Asian financial crisis, but available information suggests that the contracts were not renegotiated and profits remained healthy.

Thailand began its IPP program with a highly competitive tender in 1994—out of 88 bids from 50 bidders, seven were selected for a total of roughly 5000MW of private capacity. The predominantly natural gas-fired plans would sell electricity under long term baht-denominated contracts to EGAT, the national utility. At the time of the Asian financial crisis, only one project had signed its PPA and obtained financing—leaving many sponsors watching their potential baht denominated revenues shrink in relation to dollar-denominated obligations for fuel, equipment and capital. However, faced with the potential collapse of its entire IPP sector, the Thai government agreed to index the IPP payments to the dollar using a formula that accounted for expected levels of local and foreign costs in gas and coal fired plants. The bulk of Thailand's IPP capacity has, or will, enter operations between 2000 and 2006.

China was another early entrant into the IPP market, starting with a joint venture between Hong Kong-based China Light & Power and the Guangdong provincial government to build a nuclear facility in the 1980s. This opened the door for the first true IPP—Hopewell Holding's Shajiao B project in Shenzhen. The bulk of the Chinese IPP market blossomed during the mid-1990s, with almost US\$4 billion worth of IPP investment closing in 1997 alone. Just as precipitously, the market bottomed out, and in 2000 no project reached financial close. In China, IPPs signed long term yuan-denominated offtake agreements with provincial electricity boards. The outcomes of the IPP program have been tough on investors, while returns for China are mixed. Investors have had a very difficult time facing numerous tariff reductions and other changes to the original contract terms. On the other hand, some might argue that the government got what it wanted—FDI to help ride out a tight monetary spell in the early 1990s, and technology and management transfer from sophisticated multinationals. Increasingly, the Chinese markets have returned to liquidity and quasi-state spin-offs of the now defunct national power corporation have risen to assume a dominant role in the generation sector.

The IPP experience in **India** has been infamous for the long shadow cast by Enron's Dabhol project—a two-phase 2000MW+ naphtha and natural gas-fired facility in Maharashtra that has faced a bitter and protracted dispute. India began its IPP program with amendments to its electricity law in 1991, allowing private participation in generation, and stimulating a wave of experimentation by state governments, who share authority over electricity with the central government in India's federal system. Of the hundreds of MOU's that were signed, however, only slightly more than twenty projects ever came online, including four of the eight "fast-track" projects (of which Dabhol was one). IPPs in India signed long term, dollar indexed PPAs with (largely bankrupt) state electricity boards, and have generally fired on a range of fossil fuels (including lignite, distillate oil, naphtha) and natural gas. Outcomes for IPPs in India vary significantly across states, depending on the financial health of the SEB and the particular politics of

electricity in each state. The evolution of primary fuel markets has also been an important determinant in the IPP experience—often providing leverage for the government to pressure projects to change their terms. Our work in India has focused on the experience of projects in Andhra Pradesh, Maharashtra, Gujarat and Tamil Nadu.

The Latin American countries (except for Mexico) largely adopted a very different reform model than South East Asia. Following the example of Chile, other Latin American countries—including Argentina and Brazil—privatized most of their electricity systems, and today operate multi-buyer, multi-seller regimes that combine bilateral contract markets and spot markets for trading. In contrast to the South-East Asian model, IPPs in Latin America were regularly financed on a corporate basis, rather than on a project basis.⁹²

Argentina privatized its electricity system in 1992, in what has been recognized as one of the most successful reform efforts in the developing world, with generation, transmission and distribution unbundling and passing to private ownership. From 1992-2002, a private and fragmented generation market competed to sell electricity in a spot market in which the wholesale price of electricity declined from (US) \$41/megawatt-hour in 1992 to \$22/megawatt-hour in 1995,⁹³ and thermal power plant availability improved from 48 percent to nearly 70 percent.⁹⁴ During this time there were 45 private power plants in Argentina, of which roughly 15 were greenfield developments, rather than privatized state assets, including both hydro and thermal (mostly natural gas) plants. In 2002, Argentina faced a macroeconomic and political crisis perhaps even more severe than that in South-East Asia, which reached a dramatic crescendo in January 2002, when the government abandoned the 10-year currency board that had pegged the peso to the dollar at 1:1. Subsequently, the government converted all infrastructure contracts to pesos, beginning with electricity distribution, inviting an ongoing dispute with investors (and with the IMF) facing a dramatic erosion in revenues. Almost thirty arbitration claims have been filed against Argentina (from all sectors). The private generation sector continues to sell electricity, and the two sides weave (or stumble) their way to a settlement.

Brazil followed the example set by Argentina and Chile in 1995, embarking on an ambitious reform of its electricity sector. However, in this case the privatization ground to a halt due to lack of investor interest and political opposition, leaving 45% of the country's distribution companies and all but four of the generation companies under state control.⁹⁵ Nonetheless, generators operate in a multi-buyer, multi-seller environment, dominated by bilateral contracts between generators and either distribution companies or large users. In addition to the halting progress of privatization, the major challenge has been to attract investment in thermal capacity into an electricity system dominated by hydro

⁹² Babbar & Schuster, *supra* note 73, at 8. AES was a rare exception, relying on project finance in most of its development.

⁹³ Antonio Estache and Martin Rodriguez-Pardina, *Regulatory Lessons from Argentina's Power Concessions*, Viewpoint Note No. 92, The World Bank Group (Sept. 1996), tbl. 1.

⁹⁴ *Id.*

⁹⁵ World Markets Research Centre, *Brazil: Country Report (Energy)*, 10 May 2005, at 38.

plants.⁹⁶ Facing an energy shortage in the late 1990s, Brazil was forced to offer generous concessions to thermal IPPs that were contracted under a priority program. In Brazil's merit order dispatch system these plants suffered from poor utilization, and government entities that had been enlisted to provide support for these plants (notably Petrobras, the state oil and gas monopoly) became increasingly restive. Several arbitrations have arisen from thermal plants facing non-performance from key government counterparties.

Mexico followed the South-East Asian model, opening its generation sector to private investment in 1992 under a single-buyer model in which IPPs would sell electricity to the integrated national utility, CFE.⁹⁷ IPPs in Mexico are all natural gas-fired, combined cycle plants, awarded via competitive bidding that succeeded in generating relatively low prices. The first BOT project—Merida III—was awarded to AES over eighteen other bidders at a price of \$0.03/kWh, lower than CFE's grid rate of \$0.04-06/kWh at the time.⁹⁸ Since Merida III, twelve other IPPs have reached commercial operations in Mexico. During this time, CFE has maintained a strong payment record and our research has turned up no major contractual disputes or other challenges. Of two looming issues in the Mexican IPP sector, one appears to have been resolved. In April 2005 the Mexican Supreme Court upheld against constitutional challenge the contracts between CFE and its IPPs, which by now account for 20% of generating capacity.⁹⁹ Still looming, however, are questions regarding the sustainability of the PIDIREGAS scheme through which CFE has underwritten the BOT contracts. This mechanism is essentially a guarantee that imposes substantial contingent liabilities on CFE—liabilities that are often kept off-book. Doubts have begun to percolate regarding the ability of the loss-generating state utility to continue amassing exposure to its IPP obligations.¹⁰⁰

Poland established its IPP program in the context of a full-scale privatization of the electricity sector under the 1997 Energy Law. However, similar to the Latin American countries, Poland's reform strategy focused on the privatization of existing assets, rather than construction of new capacity. Additionally, because Poland already had sufficient generating capacity, only three greenfield IPPs have reached operations (one of which is primarily captive and thus is not part of our study). Despite the implementation of open access under

⁹⁶ In 2001, 82.7% of Brazil's electricity came from hydro plants, as opposed to 4.6% for thermal plants. *Id.* at 34.

⁹⁷ In Mexico, this was partly a result of the fact that electricity is a "public service" reserved to the State under the Mexican Constitution. In 1992, amendments were passed to the electricity law (*Ley de Servicio Publico de Energia Electrica*) that allowed private participation in certain sectors that were not "public service"—meaning that private generators could sell to CFE, but not directly to end users.

⁹⁸ Jonathan Doh and Erik Holt, *A Tale of Two International Projects in Emerging Markets: Enron in Dabhol, India and AES in Merida, Mexico*, Dept. of Management, College of Commerce and Finance, Villanova University (2003).

⁹⁹ The decision in the challenge brought by members of Congress was a narrow 6-5 split. See, *Mexico's Supreme Court upholds PPAs between state utility CFE and private firms*, Global Power Report, April 21, 2005.

¹⁰⁰ See, e.g., Morgan Stanley Equity Research (Latin America), *Electric Utilities: Power to Converge*, Jan. 27, 2003, at 15.

the 1997 Energy Law,¹⁰¹ these IPPs—an Enron natural gas plant and a coal-fired project by PSEG—sell their energy under long term contract to the Polish grid operator and local distribution companies. Continuing efforts to reform the sector, and Poland's efforts to join the European Union, have caused problems for the IPPs. The Polish legislature has made several attempts to cancel PPAs in an effort to transition to more competitive markets—however, these attempts have been accompanied by plans to provide at least some compensation. Interestingly, in addition to objections from the IPPs, these plans have faced stiff opposition from E.U. regulators who argue that such compensation is illegal support to national companies.

Turkey offers a turbulent story in the development of its IPP sector. Private generation was first authorized in 1984, but an adverse ruling from the Constitutional Court classified electricity contracts as concessions, subject to a Byzantine structure of overlapping authority from government agencies, and not subject to international arbitration. This state of affairs effectively chilled private investment until a 1994 law exempted BOT arrangements in electricity from public law requirements, providing for long-term power sales contracts with the state utility, TEAS, and Treasury guarantees for offtake and fuel supply obligations. Six IPPs, responding to solicited bids, signed contracts under this framework before the Constitutional Court struck down the law as unconstitutional in 1996. Finally, in 1997 the Turkish Parliament amended the Constitution and passed a BOO law authorizing Treasury-backed long term contracts with TEAS, resort to international arbitration and other incentives. This BOO framework has attracted almost 6000MW of competitively bid private generation capacity, at prices potentially 60% lower than the earlier BOT contracts. The major recent challenges in Turkey's private power sector stem from the devaluation of the lira—between 1999 and 2002, the Turkish lira has lost five-times of its value against the dollar, ushering in a period of stress in the IPP sector, and repeated attempts to renegotiate the dollar-denominated contracts. Thus far, the controversy continues to simmer, but our research has found no major adjustments or disputes.

Egypt opened its generation sector to private participation in 1997, with a law that laid the foundations for a competitive bidding process in 1998 for three IPPs that were awarded in 1999. All three projects sell electricity under long term contract with Egypt's national utility holding company, EEHC, that are backed with a Central Bank guarantee. Fuel for the projects, all of which fire on natural gas, is provided by the Egyptian gas monopoly at a substantial discount from market rates. The Egyptian IPPs are occasionally cited as the most competitive in the world—for example, InterGen's (now Globeleq) Sidi Krir project bid a price of US\$0.0254 per kWh. Turbulence in Egypt's IPP arrangements has arrived with a 2001 economic downturn and subsequent devaluation of the Egyptian pound from 3.2 to 6 pounds against the US dollar. The Egyptian government has soured somewhat on these projects as they grow increasingly expensive, and has prohibited the denomination or indexation of infrastructure contracts.

¹⁰¹ As of 1998, all users with annual consumption of over 40GWh are free to choose their supplier, and policymakers aim to extend this to all consumers.

Kenya stands out in our country sample for having developed IPPs within an electricity sector comprising only 1.2 GW generating capacity and in which only 15% of the population has access to electricity. The Kenyan projects arrived in two phases, beginning in 1996 with the passage of a law authorizing private participation in the generation sector. The first tender, which actually began in 1995, produced two BOO projects (OrPower4 and Tsavo Power) along a classic IPP model—20 year PPAs for energy sales to a single state utility, with minimum offtake provisions and elaborate security mechanisms. Conspicuously, none of the PPAs for these plants is supported by a sovereign guarantee; indeed, Tsavo Power became the first IPP to be financed on a project basis in Africa without a guarantee as credit support for the offtaker (OrPower4 has not secured financing yet). Due to the fact that these projects were slow in progressing from the original tender in 1995 to commercial operations for Tsavo in 2001, Kenya contracted two “stop-gap” IPPs for a total of 90MW. These projects had only seven year contracts and, because of a requirement to come online within 11 months of signing the PPA, were financed by the developers on balance-sheet. Currently, government officials report mixed feelings with the IPP experience, mainly citing the adverse impact on the balance sheet of KPLC. There has been some public controversy surrounding concerns of corruption in some of the projects. Investors in some cases remain interested in long term investment in Kenya, but have also lost interest and exited in other cases.