

# **The IPP Experience in the Philippines**

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## 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 10 developing and reforming countries (Argentina, Brazil, China, India, Malaysia, Mexico, the Philippines, Poland, Thailand and Turkey). PESD has also helped to establish 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

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### 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.



# The Philippines Electricity Market Investment Context\*

*Erik J. Woodhouse*

## I. INTRODUCTION.

This paper is part of the wider Program on Energy and Sustainable Development study on the historical experience of Independent Power Producers (IPPs) in countries that are in the midst of transforming the industrial organization of their electric power sectors. The study seeks to explain the patterns of investment in IPPs and the variation in IPP experiences. The aim is not only to assess the historical record accurately but also to chart possible future paths for the IPP mode of power sector investment. This paper follows the research methods and guidelines laid out in the project's research protocol.<sup>1</sup>

The Philippines occupies a unique position in the global experience with energy sector reform and independent power producers. The Philippine experience with IPPs has been ongoing for almost sixteen years, and has spanned a time period that includes distinct energy regulatory regimes and an ever-changing legal environment for foreign capital. Since the first contract for independent generation in 1988, the government of the Philippines has signed contracts with more than forty other IPPs, and by 1994 had more IPP contracts than the rest of the developing world combined.<sup>2</sup>

Stress washed over the IPP market in the late-1990s following the Asian financial crisis. The fiscal and monetary disruption flowing from the crisis had an immediate impact on the IPP sector in the Philippines, making the take-or-pay or capacity payments included in the power purchase agreements unsustainable. Even facing this burden, the Philippine government continued to honor the basic offtake obligations in the IPP contracts for several years, until a 2001 electric industry reform law mandated an inter-agency review of the IPP contracts. This review process led to a widely publicized renegotiation effort in the IPP sector. Although this series of renegotiations generated substantial savings for the Philippine government, the actual modifications to the contracts were minimal – in only a few cases did the changes require lender approval.

Throughout this turmoil, the Philippines has pursued an effort to restructure the previous state owned monopoly power sector into an unbundled, privatized merchant system (in which electricity is sold and traded in a wholesale market at fluctuating spot market prices). Several years of political debate preceded the 2001 passage of a far-reaching power sector reform law (the same law mandating a review of the IPP contracts) that provides a basis for a privatized market design on the model of the United Kingdom and Australia.

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\* The author would like to thank Tony Becker and Myrna Velasco for valuable discussions on the Philippine power sector, and for helpful comments on prior drafts.

<sup>1</sup> Victor, et al, The Experience with Independent Power Projects in Developing Countries: Introduction and Case Study Methods, PESD Working Paper #23 (2004), available at <http://pesd.stanford.edu/publications/workingpapers.html>.

<sup>2</sup> WORLD BANK, PHILIPPINES POWER SECTOR STUDY: STRUCTURAL FRAMEWORK FOR THE POWER SECTOR, Report No. 13313-PH (Nov. 30, 1994) at 43 [*hereinafter* WORLD BANK, POWER SECTOR STUDY].

Meanwhile, Napocor has been barred by law from signing new offtake contracts with power producers. Most existing IPPs<sup>3</sup> facing a merit dispatch system will have their contract payments covered by a universal levy, but all new development is expected to be built into a regime of bilateral contracting and spot market trading. Concurrently, the state is continuing with plans to privatize Napocor's generating assets, en route to a completely private and competitive generation sector. The substantial challenges involved in successfully implementing this model in the Philippines will be discussed below.

This paper details the broad contours of the Philippines' experience with private investment in greenfield IPPs from 1988-2004. First, a general discussion presents the country level factors relevant to understanding the IPP experience in the Philippines; in particular, it focuses on the macroeconomic, political, and social context. Second, an overview of the Philippine energy sector and a discussion of the evolution of the electricity market provide the final foundation for the IPP analysis. The paper then turns to examine the IPP experience directly, beginning with an introduction of the universe of IPP cases in the Philippines, followed by a discussion of the history of the IPP sector, from the first plant in 1990 until the recent renegotiations.

## II. THE PHILIPPINES: INVESTMENT ENVIRONMENT

### A. The Macroeconomic Context.

The Philippine economy is relatively diversified, with both human and natural resource endowments reflected in the principle sectors of (i) industry (31% of GDP), (ii) agriculture (15-17% of GDP), and (iii) services (54% of GDP).<sup>4</sup> However, a large informal sector and substantial inequality in income distribution persist as underlying structural concerns.<sup>5</sup> Per capita GDP has floated between US\$1000-1200 since the early 1980s (constant 1995 United States dollars).<sup>6</sup>

Beginning with the Aquino administration (1986-1992), the overriding economic priority has been a program of economic liberalization. The main elements of this program have been: the elimination of monopolies; opening the economy to foreign investment and reduction of trade barriers; widespread privatization of government services; and the simplification of the tax code.<sup>7</sup>

During the decade-and-a-half of IPP presence in the Philippines, the economy has performed relatively well. With the exception of a downturn during 1991-93 and again during the Asian crisis in 1998-99, growth in GDP has ranged from 4.4-6.8%. However, both inflation

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<sup>3</sup> Those with contracts approved by the ERB as of Dec. 31, 2000. See Republic Act No. 7718 (Phil.), § 32.

<sup>4</sup> Central Intelligence Agency, *The World Factbook – Philippines*, at 7 (estimated numbers for 2001), available at [www.cia.gov/cia/publications/factbook/print/rp.html](http://www.cia.gov/cia/publications/factbook/print/rp.html).

<sup>5</sup> Economist Intelligence Unit, *Philippines – Country Profile 2003*, at 32–38 (2003) [hereinafter EIU, Philippines Country Profile].

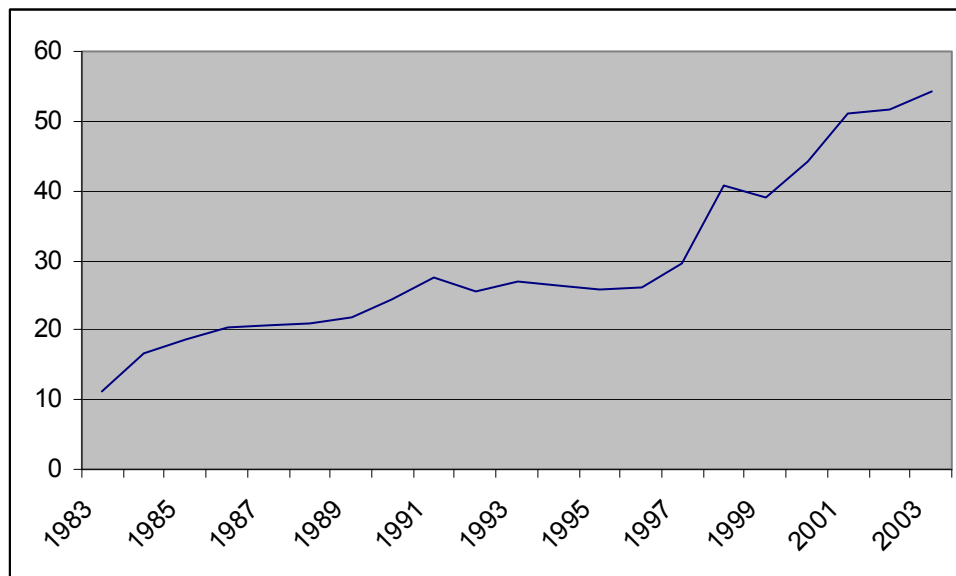
<sup>6</sup> World Bank, World Development Indicators data (2004).

<sup>7</sup> *Id.* at 27.

and exchange rate stability have been a problem. Inflation during the 1990s peaked at 18% in 1991, dropping to about 4% in 2000 and about 3% in 2003.

The most pressing challenge in the context of the IPP experience has been the persistent devaluation of the Philippine peso. The peso has lost three times its value against the US dollar since 1988, mostly stemming from the Asian financial contagion.<sup>8</sup> Exchange rates against the dollar were relatively stable during the 1990s, until 1998 brought a devaluation of roughly 30%, from 29:1 to 40:1. Since 1998, the currency has continued to decline against the dollar to almost 55:1. The chart below outlines the peso's fluctuation against the dollar since 1990. While the immediate devaluation was somewhat less severe than those in Malaysia, Thailand, or Indonesia, the Philippines has seen its currency continue to decline in the years since. In contrast, Indonesia's currency has fluctuated around the level of its dramatic 1998 devaluation, without sustained recovery. Malaysia imposed capital controls in July 1998, effectively pegging the ringgit at 3.8, where it has remained since, and Thailand's baht has recovered from a low of about 55 in early 1998 to hover around 40 in the years since.

FIGURE 1: PHILIPPINE EXCHANGE RATES (PESOS / US DOLLAR)



Source: World Bank, World Development Indicators (2004)

As in any country, the factors contributing to the macroeconomic performance are manifold. Two factors that merit attention here are the lack of adequate infrastructure and the chronically unbalanced budget. Indeed, the most important macroeconomic justifications for relying on the private sector in addressing the power shortages of the early 1990s related directly to these challenges. First, the lack of power was severely constraining growth in the Philippine economy, and the private sector was seen as the only way to finance rapid expansion in generation. Second, relying on private capital was seen as a way to cut in state spending and help balance the budget. The first goal enjoyed rapid success, as the power shortages ended in

<sup>8</sup> Data taken from International Monetary Fund statistics, available at [www.imf.org](http://www.imf.org).

almost record time.<sup>9</sup> The second goal has enjoyed more limited success, with the government avoiding a deficit in only four of the sixteen years from 1988-2003.

## B. The Social and Political Context.

For most of the 20<sup>th</sup> century, the Philippines has been a democracy, albeit with periods of military intervention by the United States and periods of military or autocratic rule. The transition since the departure of Ferdinand Marcos in 1986 has been somewhat tumultuous. President Aquino faced at least six coup attempts during her administration, and another elected president failed to finish his lawful term—President Estrada was forced from power in 2000 in a bloodless civilian coup backed by the military amid allegations of corruption and mismanagement. Despite these challenges, however, the electoral system has staged several consecutive legitimate elections, and democracy seems to be taking root. This section details briefly the broad characteristics of the Philippine political and social universe, again with special attention to factors relevant to foreign investment.

### 1. *Government Structure and Political Landscape.*

The Philippines has a republican government based on the U.S. model, with an executive presidency, a bicameral legislature, and a Supreme Court with the authority to review acts of the other branches. In 1991, the Local Government Code was passed, which devolved significant oversight and control over fiscal policy to local government entities. In addition, there are two provinces—in northern Luzon and in Mindanao—that enjoy significant autonomy, including some control over fiscal policy.

Popular political leverage is divided among an array of participants. The main political parties (those represented in Congress) tend to support the broad liberal trends in the post-Marcos era. However, as in many developing countries, there is significant popular dissatisfaction with much of the reform effort, providing a platform for populist politicians and potential dangers to businesses participating as foreign investors.

Contributing to political instability and risk, two significant rebel groups have a history of violent resistance in the Philippines.<sup>10</sup> The Communist Party of the Philippines–New People’s Army, a Maoist organization based in the Luzon countryside, has been around in various forms for several decades, but seemed to wane in importance in the 1990s despite frustrated peace talks. In Mindanao a loose umbrella of Muslim secessionist groups have committed acts of political violence, including the occasional kidnapping of foreigners for ransom. In January 2004, several power plants were entirely surrounded by Philippine security forces in response to botched attempts at sabotage.<sup>11</sup>

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<sup>9</sup> 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). Although some argue that the rapid investment during this time was due to government incentives of questionable sustainability, such as the frequent assumption by the government of fuel supply obligations and risks. See, WORLD BANK, POWER SECTOR STUDY, at 110.

<sup>10</sup> EIU, *Philippines Country Profile*, *supra* note 5, at 13.

<sup>11</sup> *Gov’t secures power plants in Negros*, *Quezon*, Philippine Daily Inquirer (Jan. 19, 2004).

Non-governmental organizations are active in the Philippines in a variety of arenas. In the context of energy generation, the environmental groups tend to be the most important, and have regularly cropped up in the news for securing judicial intervention in the operation of environmentally sensitive IPPs. Project sponsors often view the NGOs as obstacles to successfully closing or managing a plant.<sup>12</sup> The Catholic Church remains a significant political force in the country, with influence over the 85% of the population that is Catholic, and was active in toppling both Marcos and Estrada.<sup>13</sup> Trade or workers unions are not a significant force in the Philippines.

## 2. *Political and Social Risk.*

Since the end of the Marcos era, the Philippines has been seen as a promising site by foreign investors, and the consolidation of democracy has bolstered that confidence. In 1994, Standard & Poor's Sovereign Rating for the Philippines was BB, and the country held an average ranking of 52<sup>nd</sup> in the world for country risk.<sup>14</sup>

The political and social arena has proven volatile, yet largely manageable, for private energy investment. Electricity as a public good is a relatively high profile issue in the Philippines, stemming in part from the devastating power crisis that crippled the nation in the early 1990s. As detailed more closely below, the IPP sector itself has been particularly sensitive—managers of private plants are used to being called to testify before Congress regularly, and ongoing problems in the sector (including high prices and potentially looming shortages again) provide a focus for public frustration. The volatile political environment continues to pose challenges for the IPP sector—in 2005 a fierce controversy has arisen regarding proposals in Congress to rescind the VAT-tax exemption for the IPPs and prohibit the pass-through of the increased costs. This move, if approved, would trigger buy-out provisions in the IPP contracts amounting to approximately US\$27 billion. *(During the summer of 2005, the bill was passed by Congress, but the clause barring pass-through of VAT-tax payments was removed. However, the Supreme Court issued a temporary restraining order on the same day the bill was to become effective, preventing its implementation. The restraining order is due to be lifted in September 2005.)*

Nonetheless, the PPAs negotiated and signed during the 1990s were largely honored, even through the currency fluctuation and upheaval of the Asian financial crisis. The recent renegotiation of several contracts grew out of a congressionally mandated investigation into the IPP contracts generally. While renegotiation demands are well-known in all infrastructure investment, the stability of the contracts and apparent even-handedness of the government response to undeniably grave challenges stemming from the financial crisis merit special attention to the context, process and impetus for the IPP review and renegotiation. While this topic is addressed in more detail below, here it is worth observing the significant social and political risk elements in the equation – the IPP review was required under the Electric Power Industry Reform Act (2001), which also mandated that electricity bills be unbundled so that end-

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<sup>12</sup> Based on conversations with industry participants conducted via telephone and in the Philippines over a period of months.

<sup>13</sup> EIU, *Philippines Country Profile*, *supra* note 5, at 14.

<sup>14</sup> World Bank, *Mobilizing Private Capital*, at 9.

users could see the individual elements constituting the cost of electricity. This unbundling isolated a pass-through mechanism (the “purchased power adjustment”) that is ostensibly for fluctuations in fuel cost and foreign exchange for the electricity system as a whole—including Napocor’s fuel and extensive foreign currency liabilities. In the late 1990s, the devaluation of the peso caused the PPA to balloon. Although the pass-through contained significant costs flowing from Napocor itself, and costs associated with IPP payments that arguably should have been part of the base rate (such as capacity payments), the PPA became popularly associated with the IPP program. Social awareness and criticism of the IPPs grew exponentially from this point.

### C. Foreign Direct Investment Policy and Experience.

Foreign direct investment in the Philippines grew rapidly after the return of democracy in 1986, but still lags behind regional leaders such as Malaysia, Indonesia and Thailand. Overall, the manufacturing and financial sectors were the largest recipients of FDI during this time period.<sup>15</sup> Within the energy sector, investment in infrastructure grew from around \$250 million in 1991 to almost \$2 billion in 1995, led by the explosion of investment in the power sector as President Ramos fast-tracked IPP investment to deal with the energy crisis.<sup>16</sup> There are several factors commonly cited as reasons for apprehension surrounding foreign investment in the Philippines, including high labor costs, the lack of adequate physical infrastructure, uncoordinated and sometimes conflicting foreign investment promotion plans, and corruption/legal uncertainty.<sup>17</sup>

Labor in the Philippines is among the most expensive in the region relative to per capita income. However, despite low growth in value-added per worker between 1990-95, foreign investors have rated Filipino labor quite highly in terms of skill and adaptability. In the same survey however, investors noted that the rigid labor market was a significant deterrent to doing business in the country.<sup>18</sup>

Regulations controlling foreign exchange were relaxed in 1993, allowing for exchange outside of the banking system. Additionally, earnings from foreign direct investments registered with either the Central Bank or the Securities and Exchange Commission may be repatriated without restriction. The registration process can be completed with either agency.<sup>19</sup>

Land ownership is limited to Philippine nationals or corporations with at least 60% Philippine owned stock. However, foreign investors may lease commercial land subject to several requirements: the lease must be for 50 years, renewable once for another 25 years, the leased area must be used only for investment, and must comply with the Agrarian Reform Law and Local Government Code.<sup>20</sup>

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<sup>15</sup> WORLD BANK, MOBILIZING PRIVATE CAPITAL, at 9.

<sup>16</sup> World Bank, Private Participation in Infrastructure Database, at <http://ppi.worldbank.org> (accessed May 14, 2005).

<sup>17</sup> *Id.* at 4-5.

<sup>18</sup> WORLD BANK, PRIVATE SOLUTIONS, at 7.

<sup>19</sup> *Id.* at 6-7.

<sup>20</sup> *Id.* at 7. However, some projects simply have the domestic off-taker purchase the land, and provide for a lease to the IPP for the duration of the PPA/ECA contract.

The Omnibus Investment Code of 1987 aims to encourage foreign investment in the country, and provides incentives for investment in specified sectors (identified in an annual national investment priorities plan). The Foreign Investment Act of 1991 allows 100% foreign owned investment, with the exception of certain sectors prohibited in the Foreign Investment Negative List. A subsequent installation of the foreign investment negatives list allows up to 40% foreign equity interest in public utilities and BOT projects in public utilities.<sup>21</sup>

#### D. The Wider Reform Experience.

The Philippines began implementing market-oriented reform in the early 1990s, focusing on both fiscal policy (discussed above) and structural adjustment programs. The primary sectors that have led the way by integrating private investment have been power, water, telecommunications and transport, with reforms in the power sector being the most long-term and profound within this group.<sup>22</sup> Although each of these sectors has enjoyed marked success in terms of expanding production, introducing competition, and lowering costs to the government, significant macro-issues remain that affect reform efforts generally—most importantly financial and institutional development.<sup>23</sup>

Domestic financial markets in the Philippines are substantially underdeveloped, constraining the options for local financing. Historically, lending has been public, through state-owned banks or from the multilateral development banks.<sup>24</sup> Private access to both debt and capital markets has been extremely limited, consisting mostly of the few major corporations and business conglomerates in the country.<sup>25</sup> Overall, the financial sector in the Philippines is underdeveloped in comparison with the rest of South East Asia, imposing a drag on domestic investment.<sup>26</sup> This is reflected in the lower proportion of local finance in the Philippine IPPs as compared to their counterparts in Malaysia and Thailand—while the latter two countries had 90% and 75% local debt financing in their IPP sectors, the Philippines had only 3%.<sup>27</sup>

Institutional reforms continue to present challenges, both within individual sectors and to the economy as a whole. The coordination of both authority (which government entities hold relevant power over given projects) and planning (which projects get approved) has been deficient, leading to criticisms of uneven supply of privatized public goods across the islands.<sup>28</sup> Even when lines of authority are clear, relevant agencies have often lacked the financial resources to fund independent feasibility studies and generate comprehensive development plans—meaning that (outside the power sector) most bids for private contracts have been

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<sup>21</sup> WORLD BANK, PRIVATE SOLUTIONS, at 8.

<sup>22</sup> *Id.* at 1.

<sup>23</sup> *Id.* at 2–3.

<sup>24</sup> *Id.* at 12–13.

<sup>25</sup> *Id.*

<sup>26</sup> EIU, *Philippines Country Profile*, *supra* note 5, at 38.

<sup>27</sup> Lefevre and Todoc (2000). “IPPs in APEC Economies: Issues and Trends.” Paper presented at “The Clean and Efficient Use of Fossil Energy for Power Generation in Thailand,” APEC Clean Fossil Energy Experts’ Group, Bangkok, Thailand, 30 October – 3 November 2000, *available at* <http://rru.worldbank.org/Documents/PapersLinks/thierry.doc>.

<sup>28</sup> WORLD BANK, PRIVATE SOLUTIONS, at 15.

unsolicited.<sup>29</sup> Additionally, the experience with independent regulators has been uneven, with criticism of undue influence from both private investors and political authorities common. Corruption and legal uncertainty are prominent concerns for both investors and regulators.<sup>30</sup>

### III. THE PHILIPPINES: ELECTRICITY MARKET CONTEXT AND IPP EXPERIENCE

With 7,000 islands to cover, the Philippines faces unique electricity market challenges in providing electricity services across the country.<sup>31</sup> Of the three largest islands—Luzon, Visayas and Mindanao—Luzon (which includes Manila) accounts for 75% of all energy demand and 87% of installed capacity.<sup>32</sup> Visayas on the other hand, while accounting for roughly 12% of demand, boasts of only 0.1% of installed capacity.<sup>33</sup> One region in Visayas has watched peak demand increase from 131MW to 190 MW over the past five years, while installed capacity reaches only 110MW.<sup>34</sup> Several pipeline inter-island transmission projects have been proposed and/or implemented in recent years to combat this problem. Despite these efforts, progress has been slow because addressing disparities of this type is significantly more difficult in an island nation with natural barriers to energy transmission. Rural electrification has been a consistent goal of the government for some time—in some cases the government has enlisted the support of IPPs in this task, but the trend does not seem to be widespread.

#### A. Government and Industry Organization.

##### 1. *Industry Organization.*

As in many countries, the development of the electricity sector in the Philippines began with substantial private investment. However, following the nationalization of several plants by the Marcos government, generation in the Philippines was a state monopoly until an executive order in 1988 (“Executive Order 215”) opened the door to private generating companies. The growth of IPPs within the generation sector has been rapid—by 2001, Napocor supplied 59% (6,950 MW), Napocor IPPs 31% (3,667 MW), and non-Napocor IPPs 10% (1,168 MW) of national generation capacity.<sup>35</sup> Transmission has been an NPC monopoly through the 1990s and only with the EPIRA law has there been a move towards privatization.<sup>36</sup> Distribution has always been handled by a variety of private utilities and electricity co-operatives—Meralco is the dominant distributor in the country.

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<sup>29</sup> *Id.* at 10.

<sup>30</sup> The Philippines ranked 92<sup>nd</sup> (near the bottom) of the 2003 Transparency International Corruption Perceptions Index, available at <http://www.transparency.org/cpi/2003/cpi2003.en.html>.

<sup>31</sup> A World Bank study has implied that the difficulties of locating generation and transmission assets has led to a situation in which the country has generation capacity installed in the wrong places. WORLD BANK, POWER SECTOR STUDY, at 43.

<sup>32</sup> Pamela Sio, *All Charged Up*, Makati Business Club Research Reports, No. 38, April 2002, available at [http://mbc.com/ph/economic\\_research/mbcrr/no38/default.htm](http://mbc.com/ph/economic_research/mbcrr/no38/default.htm).

<sup>33</sup> *Id.*

<sup>34</sup> *The Philippines: the challenge of juggling market reform and expansion*, Energy Economist, Issue 266, at 15 (Dec. 2003).

<sup>35</sup> Sio, *All Charged Up*, *supra* note 32.

<sup>36</sup> NPC's technical performance in this arena has been relatively solid. In 2001, electricity losses were 12% of total generation—about average when compared to the other countries in the wider IPP study. WORLD BANK DEVELOPMENT INDICATORS, 2004.

The principal suppliers of electricity services, for the purposes of this study, are Napocor (or NPC) and Meralco.

Napocor is the state owned utility that once enjoyed a complete monopoly on generation and transmission, and is now in the process of privatization and divestiture. Meralco is the largest distribution utility in the country, serving the Manila area and five neighboring provinces, and is relevant in the history of IPPs in the Philippines. There has been widespread criticism, and some indication, of regulatory capture by Meralco of Napocor and the ERC.<sup>38</sup>

TABLE 1: ENERGY SECTOR OWNERSHIP AND RESTRUCTURING

	Pre-reform	1988-2001	Post-EPIRA
<b>Generation</b>	NPC monopoly	NPC generation; IPP generation	IPP generation (planned)
<b>Transmission</b>	NPC monopoly	NPC monopoly	Private transco <sup>37</sup> (planned)
<b>Distribution</b>	Private utilities (e.g. Meralco); Private cooperatives		

## 2. Government Organization.

The overall management of the electricity sector falls under the jurisdiction of the Department of Energy (“DOE”). Established in 1992, the DOE sets overall energy policy and houses the Energy Regulatory Commission. More importantly, the DOE is responsible for overseeing the implementation of the 2001 EPIRA law that restructures the entire energy sector.

Prior to the opening of the generation sector to private investment, the national electricity utility, National Power Corp. (“Napocor” or “NPC”) was responsible for all generation and transmission in the Philippines. NPC’s monopoly over generation was eliminated with EO 215, which formed the basis for the entry of IPPs into the sector. NPC’s remaining generation assets and monopoly over transmission are in the process of being sold off pursuant to the 2001 EPIRA law. In order to facilitate this process, the national government will assume part of NPC’s enormous debt burden—roughly \$3.7 billion out of a total of US\$6.7 billion in 2001—but will avoid the costly annual support that the utility required, which totaled approximately US\$750 million annually.<sup>39</sup> The entity responsible for managing the privatization of Napocor is the Power Sector Assets and Liabilities Management Corporation (“PSALM”). This is the state-owned entity charged with implementing the privatization of NPC’s assets, including generation and transmission assets and Napocor’s IPP contracts. Additionally, PSALM was responsible for implementing the findings of the EPIRA mandated review of the IPP contracts after 2001.

The Philippines has made a couple of attempts at establishing an independent regulator. The Electricity Regulatory Board was established via executive order in 1987 to assume this task, but had limited powers and resources, no independent budget, and was generally ineffective

<sup>37</sup> Although Congress approved the PSALM privatization plan on Mar. 13, 2002, privatization remains slow due to continuing political debates regarding the transfer of a franchise to private investors. *Privatizing Philippine National Power Corp Good for All: Gov’t*, ASIA PULSE, Sept. 24, 2002.

<sup>38</sup> For example, Meralco and Napocor renegotiated, on Meralco’s insistence, the agreement governing their power purchase arrangements to allow Meralco to source more of its energy needs from its own IPPs, two of which are controlled by the Lopez family, which also holds a 22% interest in Meralco. *Higher Philippine Power Rates Seen After Meralco/Napocor Deal*, ASIA PULSE, July 23, 2003.

<sup>39</sup> *The Philippines: the challenge of juggling market reform and expansion*, Energy Economist, Issue 266, at 15 (Dec. 2003).

in its supposed role. Its successor, the Electricity Regulatory Commission, established in 2001, was granted significantly more autonomy and resources. This quasi-judicial body oversees the implementation of EPIRA, including authority over: (1) Regulating transmission and wheeling charges and retail tariffs for end-users, (2) Granting and regulating certificates of compliance required of all industry participants, (3) Reviewing the unbundling of business activities. Thus far, however, even these expanded powers have not been sufficient to prevent political meddling in its rate-setting decisions, and doubts remain as to the “independence” of regulation in the Philippines .

### 3. *The 2001 Reforms.*

The most recent, and ongoing, chapter in this history began in 2001 with the passage of the Electric Power Industry Reform Act (Republic Act No. 9136, or “EPIRA”). This process involved: (i) the privatization of all Napocor generation and transmission assets, (ii) state absorption of Napocor’s stranded debt (roughly 200 billion pesos), (iii) a congressional investigation and review of all current IPP contracts (*see below, “The Renegotiations”*), and (iv) the mandated unbundling of rates. The review of IPP contracts and the unbundling of rates have been implemented—each with consequences for the IPPs in the country—in the years since the passage of the EPIRA law. (*Each is commented on in further detail below*).

Fundamentally, the EPIRA law seeks to further liberalize the electricity sector. This targeted market structure includes a fully private generation market, in which power producers would compete in a private bilateral contract market for sales to distribution companies and large users, and the establishment of a spot market for system balancing. Several challenges have arisen in this process, and the Philippines currently is in the midst of making a difficult transition to a private generation market.

In the generation sector specifically, Section 29 of the law provides that although the generation sector is a business that is intimately connected to the public interest, generation companies selling electricity to the contestable market are not considered to be public utilities and therefore not required to have a national franchise. Further, the prices charged by these suppliers are not subject to regulation by the ERC.<sup>40</sup>

#### B. Capacity, Demand and Consumption.

By 1998, peak capacity was 11,988 MW while peak demand was 6,421 MW. Demand projections in the early- and mid-1990s forecast demand growth ranging from 9.5-12% per year,<sup>41</sup> although these projections were abruptly derailed by the Asian financial crisis. However, a 1994 report by the World Bank already warned implicitly against the risk of over-commitment through the uncoordinated signing of PPAs, which essentially passed demand risk to the consumer through take-or-pay provisions.<sup>42</sup>

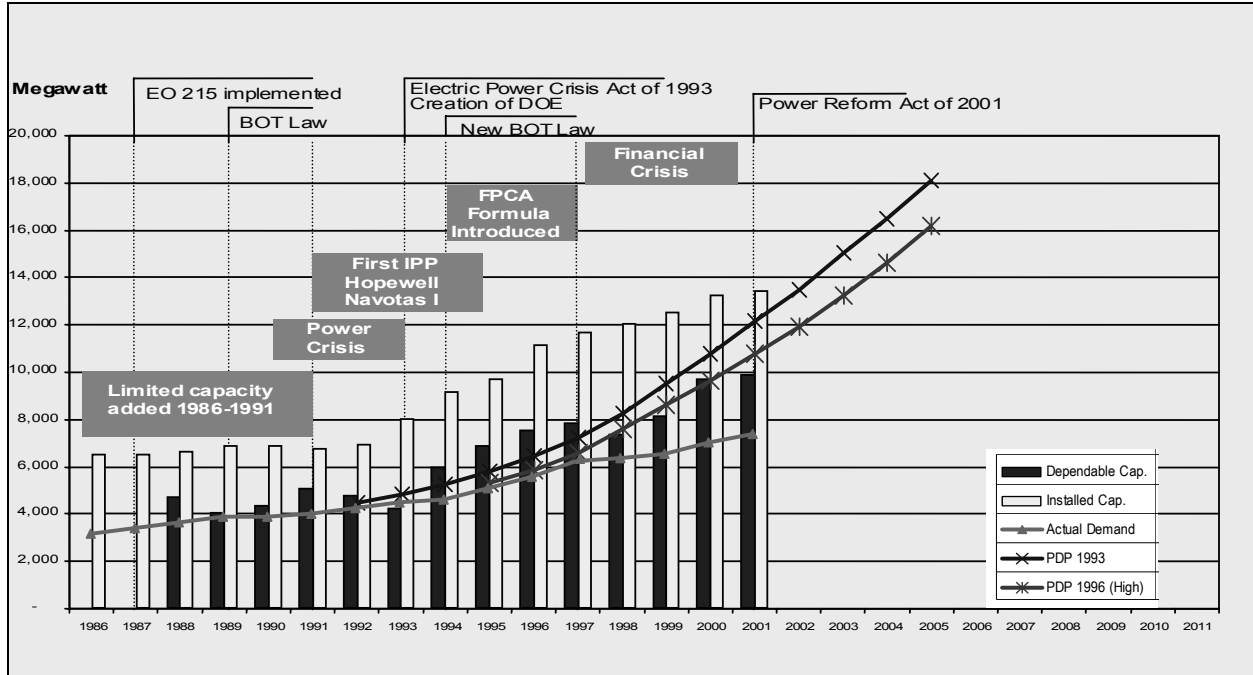
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<sup>40</sup> Republic Act No. 7718 (Phil.), sec. 29.

<sup>41</sup> NPC based its projections on higher GDP growth forecasts (8%/year) and used the 12% figure, while the World Bank remained skeptical, relying on a lower GDP growth forecast to arrive at the energy demand growth of 9.5% per year. WORLD BANK, POWER SECTOR STUDY, at 12–13

<sup>42</sup> WORLD BANK, POWER SECTOR STUDY, at 46–48.

FIGURE 2: PHILIPPINES ELECTRICITY SUPPLY-DEMAND BALANCE IN THE 1990S



Source: Adapted from Fernando Y. Roxas, *Why is Napocor Losing So Much Money?* (2005) (unpublished paper on file with author)

With economic recovery underway, current estimates indicate a supply shortfall by the next decade and the government is again hoping to attract private investment to meet demand.<sup>43</sup> As discussed in more detail below, however, the sector is gridlocked with substantial uncertainty surrounding the new privatized market design, and the potential for generation capacity shortfalls in the coming years is becoming increasingly serious.

### C. Electricity Prices.

The cost of electricity in the Philippines is high. Fundamentally, this is the result of basic characteristics of the electricity market in the Philippines, however, the high cost was substantially exacerbated by the IPP sector in the aftermath of the Asian financial crisis. Retail tariffs are composed of two elements – the Basic Rate and the Purchased Power Adjustment (*see below*). The Basic Rate has not been revised upward since 1994. The Purchased Power Adjustment (“PPA”) is a pass-through mechanism that reflects the indexation provisions in Napocor’s generation costs and IPP contracts—covering such things as fuel costs and foreign exchange changes, and in the late 1990s, IPP capacity payments. Table 2, below, shows representative retail tariff rates for selected South-East Asian countries.

<sup>43</sup> In 2003, the government forecast demand growth of 9-10% per year over the next decade, meaning that installed capacity would have to increase from 13,000MW in 2001 to 22,000MW in 2010. *The Philippines: the challenge of juggling market reform and expansion*, Energy Economist, Issue 266, at 15 (Dec. 2003).

TABLE 2: RETAIL ELECTRICITY TARIFFS ACROSS SELECTED ASIAN COUNTRIES (JUNE 1998)

Utility	Residential Tariff	Industrial Tariff
Perusahaan Listrik Negara, <i>Indonesia</i>	0.63	0.66
Korea Electric Power Corp., <i>Korea</i>	4.83	1.95
Metropolitan Electricity Authority, <i>Thailand</i>	5.54	2.24
Tenaga Nasional Berhad, <i>Malaysia</i>	5.92	2.39
Taiwan Power, <i>Taiwan</i>	6.46	2.41
Singapore Power, <i>Singapore</i>	6.96	2.84
Manila Electric Company, <i>The Philippines</i>	9.51	3.84
China Light & Power, <i>Hong Kong</i>	11.46	4.63
Kansai Electric, <i>Japan</i>	12.18	4.92
<i>The peso exchange rate against the dollar in June 1998 was P49.39 to \$1</i>		

Source: Myrna Velasco, *Surviving a Power Crisis* (2005), at 85.

The cost of electricity in the Philippines is constrained by several factors.<sup>44</sup> First, unlike many other countries in the IPP study, the Philippines has no extensive domestic reserves of fuel and even NPC must import most of its fuel needs. Second, the Philippines must invest substantially more resources in its transmission infrastructure than most other countries, primarily because the transmission challenges implied in delivering electricity to hundreds of dispersed islands raises the cost of transmission substantially. This is exacerbated by the need to build transmission infrastructure capable of withstanding earthquakes and tropical storms. Third, the lack of local capital markets or sufficiently liquid banking sector means that even the government must borrow abroad for most of its finance. Fourth, the electricity demand curve in the Philippines is relatively “peaky” in comparison to other countries. The lack of a strong industrial base in the country means that there is very little baseload demand on a 24-hour basis that might help defray the cost of installing facilities to cover peak demand. Finally, the Philippines has no domestic source for the equipment necessary for modern electricity infrastructure. Almost every major input for the electricity sector must be imported at international prices and subject to foreign exchange risk.

These immutable characteristics were exacerbated by the structure and implementation of the IPP program. The rapid build-out of IPPs during the 1990s meant that with the impact of the Asian financial crisis in 1998, the cost of electricity began to explode increase dramatically due to a combination of the high fixed cost of the IPPs (capacity payments or minimum offtake) and the escalating foreign exchange liability stemming from deep reliance on foreign capital. The controversial “PPA” pass-through mechanism began climbing rapidly with the crisis, eventually becoming larger than the base rate itself.

#### D. Fuel Mix for Electricity Generation.

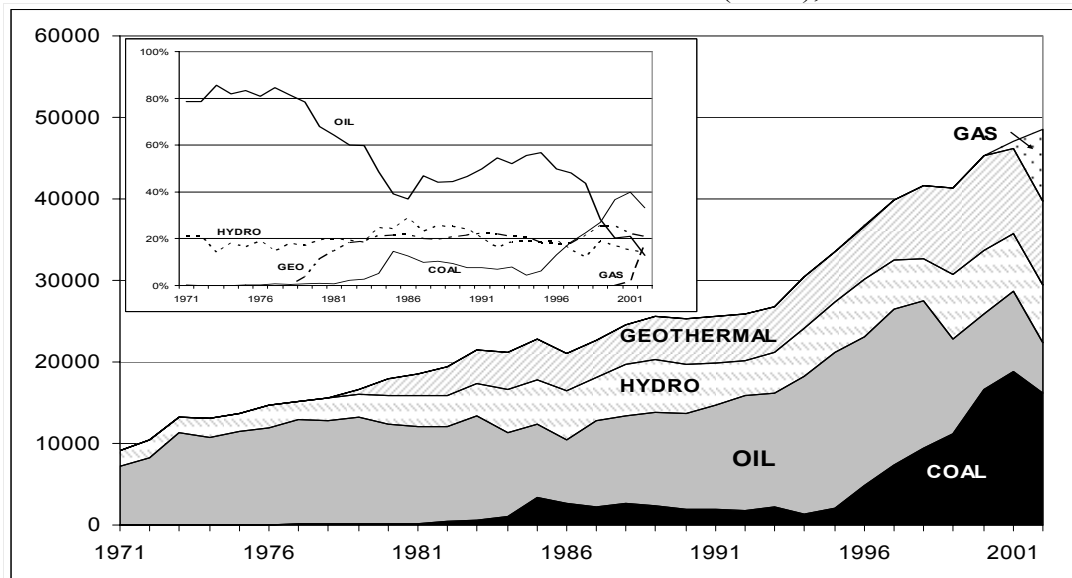
Figure 1 below shows electricity generation in the Philippines by fuel, both in GWh and as a percentage of total generation (inset). As is evident in the chart, a heavy reliance on oil is being slowly eroded by a gradual movement to increased use of gas-fired plants, spurred both because of a need to reduce reliance on oil imports and because the country has discovered

<sup>44</sup> The following analysis is adapted from Fernando Roxas, *Why is electricity in the Philippines so expensive* (unpublished manuscript on file with author).

domestic gas reserves.<sup>45</sup> The Malampaya natural gas field—under development by Shell—is estimated to have gas reserves in excess of 400-450 million cubic feet per day for 20 years.<sup>46</sup> Gas from this reserve is channeled to Kepco’s 1200 MW Ilijan plant (selling to NPC) and to First Gas Power Corporation’s 1000 MW Santa Rita and 500 MW San Lorenzo plants (selling to Meralco).

Geothermal plants have also gained prominence—the Philippines has the second highest geothermal generation in the world (1,931 MW).<sup>47</sup> Although geothermal power only accounts for 16% of total capacity, geothermal plants provided 27% of actual electricity production in 2002.<sup>48</sup>

FIGURE 3: PHILIPPINE ENERGY GENERATION (GWH), BY FUEL



Source: IEA

#### IV. THE PHILIPPINES IPP PROGRAM.

##### A. Overview.

Consistent with other many developing country experiences, the Philippines initially moved towards independent power generation as a response to crisis<sup>49</sup>—in this case, the immense power shortages in the late 1980s and 1990s—however, this move became the foundation for a sustained and energetic push towards a competitive wholesale energy market. During this time the legal regime and context within which IPPs were negotiated shifted several times as the leverage and sophistication of the local authorities improved.

<sup>45</sup> *Id.* At 15

<sup>46</sup> WORLD BANK, PRIVATE SOLUTIONS, at 23.

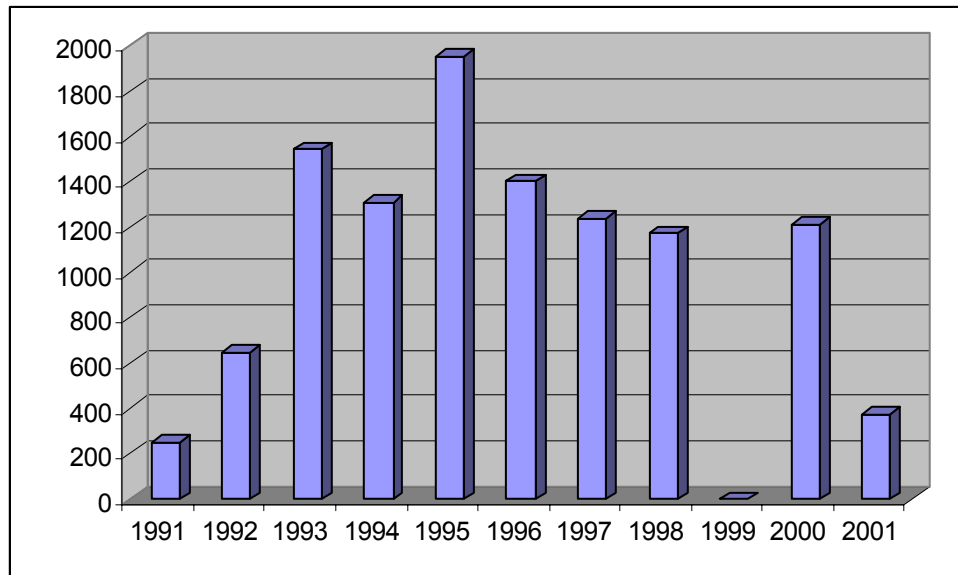
<sup>47</sup> *The Philippines: the challenge of juggling market reform and expansion*, supra note 65, at 15.

<sup>48</sup> *The Philippines: the challenge of juggling market reform and expansion*, supra note 65, at 15.

<sup>49</sup> Thomas C. Heller and David G. Victor, *A Political Economy of Electric Power Market Restructuring: Introduction to Issues and Expectations*, PESD Working Paper #1 (2003), available at: <http://pesd.stanford.edu/publications/20181/>.

The IPP sector in the Philippines developed in three main rounds. First, the plants contracted in the early 1990s to address the power crisis were largely oil-fired plants with 5-12 year PPAs. These tended to be expensive because: (1) the rapid capital recovery period under short PPAs, (2) the extreme pressure on government negotiators stemming from the grave electricity crisis, and (3) the high fuel cost oil plants were dispatched as baseload facilities during the crisis. Second, a wave of large baseload coal plants – most importantly Pagbilao (700MW), Sual (1200MW)<sup>50</sup>, and Quezon (originally 440MW, now rated at 460MW). These reached operation between 1996 and 2000 and had longer PPAs (up to 25 years). Third, a round of big hydro/irrigation projects and natural gas plants that reached operation from 1998 to 2002, including Casecnan hydro (140MW), San Roque hydro (345MW), CBK hydro (640MW), Ilijan natural gas (1200MW), Santa Rita natural gas (1000MW) and San Lorenzo natural gas (500MW).

FIGURE 4: GREENFIELD PRIVATE INVESTMENT ELECTRICITY IN THE PHILIPPINES, 1990-2001



To understand the rush to welcome private investment in the early 1990s, it helps to also see the cost of the chronic blackouts of that time. At the peak of the shortage, the blackouts averaged 12-14 hours per day, 300 days per year. A World Bank report in 1994 estimated that gross economic cost of the outages was US\$0.50/kWh. Thus, even though IPP-generated electricity (average cost US\$0.0652/kWh) at the time was more expensive than NPC-generated electricity (US\$0.0637/kWh), the inability of the government to finance rapid expansion of the power sector made private investment extremely attractive. Once the power crisis abated, and the government had learned from its early IPP experiences, prices fell again—the average post-power crisis IPP was 12% less expensive in terms of cost/kWh than its predecessors, a result of both a more competitive bidding environment and a shift away from expensive fuel.<sup>51</sup>

<sup>50</sup> Mirant's Sual Pangasinan coal-fired plant has an installed capacity of 1200MW, but only 1000MW under contract with Napocor. The remaining 200MW is sold via a joint marketing agreement with Napocor to large industrial users.

<sup>51</sup> WORLD BANK, POWER SECTOR STUDY, at 43.

## B. Development of the Philippines IPP Sector.

### 1. *Early Stages – Executive Order 215 and the 1990 BOT Law*

Independent power producers entered the Philippine market in 1988, under the aegis of an executive order from President Aquino driven by the need to address looming power shortages in the island. Rules and regulations for EO 215 were passed in 1989, after the first IPP contracts had been signed. This order authorized private generators to build plants and supply power to both NPC and local distributors, effectively ending NPC's monopoly in generation, while maintaining the state monopoly on transmission. However, this order also required that an IPP must supply energy at prices less than Napocor prices and rely on domestic or unique fuel supplies to qualify.<sup>52</sup>

Under EO 215, the IPP process was essentially one of direct negotiation between the Philippines government and project proponents.<sup>53</sup> Competition under these circumstances was limited. Reviews of the IPP experience up to 1994 note a high mortality rate of projects in the Philippines never proceeding to financial close.<sup>54</sup> During this period, Hopewell's Navotas I project was the only IPP to reach financial closure.

In 1990s, the Philippines became one of the first developing countries to pass specific enabling legislation for a BOT regime in 1990.<sup>55</sup> This framework contemplated a competitive bidding process for all infrastructure projects that was significantly curtailed with respect to power projects with the passage of the 1-year Electric Power Crisis Act (*see below*). The BOT Law was updated in 1994 with Republic Act 7718, which expanded the possible variations on the BOT framework, and invited unsolicited bids for power projects (prior to this point, the government specified the location, fuel and other general requirements for the IPP before soliciting bids).<sup>56</sup>

Several deals were inked during his phase of development, including Hopewell's 700MW Pagbilao coal-fired plant. However, these projects were not sufficient to relieve the deepening electricity shortage that crippled the Philippines during 1991-1993, and in April 1993, Congress approved emergency powers for the executive to address the shortage.

### 3. *The Electric Power Crisis Act.*

Despite the commissioning of the first IPP in 1991 (Hopewell's Navotas I plant), expansion of generation capacity remained almost at a stand-still—in 1992, not a single new private plant came online, spurring the onset of rolling blackouts.<sup>57</sup> In response, Congress

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<sup>52</sup> *Higher Philippine Power Rates Seen After Meralco/Napacor Deal*, Asia Pulse (July 23, 2004).

<sup>53</sup> WORLD BANK, POWER SECTOR STUDY, at 43.

<sup>54</sup> WORLD BANK, POWER SECTOR STUDY, at 48.

<sup>55</sup> Republic Act No. 6957 (Phil.).

<sup>56</sup> Republic Act No. 7718 (Phil.).

<sup>57</sup> This is the World Bank's explanation for the proliferation of stalled and cancelled projects during this period. *World Bank Staff Appraisal Report, Philippines Leyte-Cebu Geothermal Project*, Report No. 11449-PH (Jan. 6, 1994), at 3.

passed the 1993 Electric Power Crisis Act, authorizing the executive to negotiate IPP contracts on a fast track basis. In terms of addressing the power shortage, this law was an immense success—several thousand megawatts of generating capacity was installed in the country in the first 18 months, a power surge that would have taken years in other circumstances. Most of the generating capacity built during this time was based on combustion turbines or diesel systems<sup>58</sup>—the only generation plants that could be brought to operation within a year—which are characterized by low initial capital costs, but high operating costs. The fast track authority under this law expired in April 1994.

#### 4. *Post-Electricity Crisis ... Continued Development.*

After the power crisis abated, the Philippines continued to contract IPPs in order to support high expected economic and demand growth. These projects included several large baseload coal plants (e.g. Sual, Pagbilao), and the large natural gas and hydro facilities that came online in the late 1990s.

As the IPP program matured, the government was able to attract increasingly competitive projects. These improvements stemmed from several factors. First, and most obviously, is the fact that a government trying to address a massive power shortage is not negotiating from a position of strength. Additionally, the government became increasingly stingy in allocating performance undertakings to bolster Napocor's credit. A 1995 policy paper began to limit extension of the PU, and in all, only 16 IPPs received this type of guarantee from the government, most in the first half of the decade.

However, the issue may be more complex than that. Many of the early IPPs were for projects for which NPC had pre-determined the location, size, and fuel for the plant, thus foreclosing the efficiency gains of engaging private sector expertise in these areas.<sup>59</sup> This situation changed when the 1994 update to the BOT Law was passed, allowing unsolicited proposals for projects, and when the fast-track authority lapsed, reinstating the competitive bidding arrangement set forth in the original BOT Law (although the vast majority of IPPs were solicited).

By 1998, foreign owned IPPs accounted for US\$6 billion of investment and 4800 MW of generating capacity.<sup>60</sup> Over 90% of new capacity installed during the 1990s came from foreign-owned IPPs.<sup>61</sup> However, as the Asian financial crisis took its toll, electricity demand in the country began to fall short of projections, and the Philippines entered an era of overcapacity in the energy market. Just as demand growth was flattening, 2700MW of natural gas-fired generation came online – the Santa Rita, San Lorenzo and Ilijan projects. These plants were

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<sup>58</sup> *Id.* At 10.

<sup>59</sup> WORLD BANK, POWER SECTOR STUDY, at 47–48.

<sup>60</sup> Fernando Y. Roxas, *The Importance and the Changing Role of the Independent Power Producers in the Proposed Competitive Power Market in the Philippines*, at 1, Conference Paper for APEC 8th Technical Seminar & 7th Coal Flow Seminar, Bangkok (Oct. 30–Nov. 1, 2001), available at <http://rru.worldbank.org/PapersLinks/Independent-Power-Generation-Project-Finance/>.

<sup>61</sup> WORLD BANK, POWER SECTOR STUDY, at 43.

arranged at the behest of the central government in order to provide a market that would support the development of the offshore Malampaya natural gas field.<sup>62</sup>

Because of the take-or-pay provisions that were part of every IPP contract in the Philippines and the progressive devaluation of the peso, the price per kWh in Pesos began to soar. These increases were passed on directly to the consumers, who shortly began to pay the highest rates in South-East Asia. Criticism of the government's handling of the IPP projects began to grow<sup>63</sup>—fueled by speculation that the IPPs collectively were expensive alternatives to NPC generated power.<sup>64</sup> As in many countries that experimented with private generation in the 1990s, such generalizations are as popular as they are suspect.<sup>65</sup>

### C. Investors.

IPP investors in the Philippines are, like fuel sources, relatively diversified. Most of the major US investors (Mirant, El Paso, Enron, Covanta, CalEnergy, Intergen) have one or more plants in the country. The largest foreign investor in the IPP market in the Philippines is Mirant Corporation, with 2,296 MW of generating capacity.<sup>66</sup> Several Asian utilities have also participated, including Marubeni, Kyushu Electric, Kansai Electric (Japan) and Kepco (Korea). Equipment suppliers and industrial interests round out the mix, with Tomen and Mitsubishi (Japan) and Alsons (Phil.) playing a role. Domestically, the critical player is First Gen, a Philippine company owned by the prominent Lopez family. The Lopez' holding company, First Philippines Holding Company, also holds a 26.8% stake in Meralco, although they are popularly perceived to be in control of the Manila distributor.

There are reports of investors complaining that “insiders” have received special treatment, but these are little more than vague accusations. Where investors have paired with an influential local partner, the arrangement has often turned around on them, particularly as details of the recent renegotiations leak stories of insider deals, corruption and kickbacks.<sup>67</sup> The Lopez family itself, while capable of marshalling its own political resources, is equally a target in the populist political environment of the Philippines.

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<sup>62</sup> See *supra* note 46 and associated text.

<sup>63</sup> See, e.g., Sheila Samonte-Pesayco and Luz Rimban, *Ramos Friends Got Best IPP Deals*, Philippine Center for Investigative Journalism (5-8 August 2002), at <http://www.pcij.org/stories/2002/ramos3.html>.

<sup>64</sup> See, e.g., Evangeline L. Moises, *IPPs not keep on Napocor's plan to buy out supply deals*, Business World, April 6, 2000, at 6. However, some argue that the widely criticized “fast track” projects, despite their substantially higher cost, were more valuable economically because of their role in ending the power blackouts. WORLD BANK, POWER SECTOR STUDY, at 46.

<sup>65</sup> *The Philippines: the challenge of juggling market reform and expansion*, Energy Economist, Issue 266, at 15 (Dec. 2003).

<sup>66</sup> *The Philippines: the challenge of juggling market reform and expansion*, Energy Economist, Issue 266, at 15 (Dec. 2003).

<sup>67</sup> For example, the 63MW diesel Cavite EPZ plant has come under special scrutiny as details of arrangements between the local legal counsel to the project and his brother, then chief legal counsel to President Ramos, have swirled amid reports that the IPP cannot generate sufficient electricity to meet its obligations and has been buying energy from NPC and selling it at a higher price. Sheila Samonte-Pesayco and Luz Rimban, *Ramos Friends Got Best IPP Deals*, Philippine Center for Investigative Journalism (5-8 August 2002), at <http://www.pcij.org/stories/2002/ramos3.html>.

#### D. Contracts (Facilities and Purchase Arrangements).

Independent power producers operating on contracts signed between 1988 and 2001 sell their energy either to a central government entity (NPC, NIA, or PNOC) or directly to local utilities (usually MERALCO). In the case of fossil-fuel fired units, power sales agreements are concluded between the IPP and NPC. Geothermal plants generally will sell their output to PNOC-EDC, which will in turn onsell the power to NPC. Hydro plants sell electricity and irrigation water to the National Irrigation Administration, which onsell the electricity to Napocor. Meralco has signed PPA's (power purchase agreements), directly with three IPPs (Quezon, Santa Rita, and San Lorenzo).

Offtake arrangements are captured in either a power-purchase agreement ("PPA") or an energy conversion agreement ("ECA"). Generally, IPPs sign ECAs (often referred to as "tolling agreements") in which fuel is supplied by the government counterparty free of charge and the IPP is paid for converting that fuel to electricity. Even when the offtake is captured by a PPA, NPC will provide the fuel and costs are treated as a pass-through element in the tariff. With few exceptions,<sup>68</sup> no wider commitments were placed upon their operations—the transmission sector is only now seriously moving towards privatization, the distribution sector was not a major sector for foreign private investment, and a competitive contract market is only a plan even in 2004.

Ownership structure for IPPs in the Philippines is dominated by the BOT form. The prevalence of BOT contracts as opposed to other forms results from the fact that the "transfer" element of the project makes the project eligible for a sovereign guarantee.<sup>69</sup> Formally, only solicited projects are eligible for this guarantee – a rule that invited substantial controversy in the case of the CBK hydro project, which although unsolicited, received a performance undertaking from the Department of Finance.

The first BOT contract for an IPP (the Hopewell Navotas I plant) was, as of 1994, the blueprint for all IPP contracts. This model contemplates significant assumption of risk by the government, either through direct guarantees (for contracts entered into prior to the BOT Law, which limited the availability of explicit government guarantees) or through indirect guarantees such as obligations to provide fuel, and payment in U.S. dollars. Subsequently, another Hopewell project – the 700MW Pagbilao plant, negotiated over a period of four years from 1990-1994 – updated this blueprint and provided the dominant model for subsequent projects. It was indeed common for projects to shift all risk except construction and operation to the

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<sup>68</sup> The Caliraya-Botocan-Kalayaan plant provides frequency and voltage regulation in the Luzon grid, as well as "spinning reserve." Dominic Jones, *Nothing vanilla in Manila*, PROJECT FINANCE, May 2000, p. 31.

<sup>69</sup> Philippines Power Sector Study: Structural Framework for the Power Sector, World Bank Report No. 13313-PH (Nov. 30, 1994) at 43.

government off-taker, as in the Pagbilao project.<sup>70</sup> Generally, a range of other risks were borne by the government party.<sup>71</sup> Common elements of risk allocation in the Philippines include:

- *Market Risk.* The common take-or-pay provisions usually set the minimum energy off-take in the 70-85% range.<sup>72</sup> Through the purchased power adjustment, NPC is authorized to pass the costs associated with the take-or-pay provisions on to consumers.
- *Fuel Risk.* Under ECAs, the off-taker agrees to supply the fuel. Even IPPs that sign PPAs in the Philippines often have fuel pass-through clauses, which effectively shift price and availability risk to the off-taker.
- *Foreign Exchange Risk.* Most of the IPP contracts included large US dollar-denominated components, meaning that NPC shouldered the bulk of the foreign exchange risk, except to the extent passed on to consumers in the PPA.
- *Other Payments.* The IPP contracts generally included both cost-recovery and operating and maintenance elements, which are also subject to escalation. In the recent ICR Report, escalation clauses were cited as a common source of problems in the contract.
- *Sovereign Guarantee.* With very few exceptions, NPC's obligations under its agreements with the IPPs are backed by a sovereign guarantee.

Despite the general hesitation by investors regarding the status of rule of law and corruption (see discussion above), investors have readily responded to legal incentives (such as the EPCA and BOT Laws) and to the favorable terms of the contracts signed by Napocor during the early years of the IPP program. Some commentators observe that foreign investors seemed relatively more willing to rely on sophisticated contractual safeguards that depended on *ex post* enforcement than in other South-East Asian countries such as Malaysia or Indonesia.<sup>73</sup>

New IPPs negotiating contracts after the EPIRA legislation will have to face the reality that NPC can no longer contract for generation.<sup>74</sup> Rather, IPPs must contract directly with local utilities or large users, occasionally including transmission contracts with the National Transmission Corporation. Additionally, most new projects are negotiated in the shadow of the looming Wholesale Energy Spot Market (WESM). In light of plans to introduce a contract market in the energy sector, new IPPs are drafting contracts that contemplate PPA arrangements with an offtaker (distributor or industrial consumer) until such time as the WESM goes online, at which point the physically settled PPA contracts will become a cash settled swap contract, similar to a contract for differences.<sup>75</sup>

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<sup>70</sup> Withold J. Henisz and Bennet A. Zelner, *The Political Economy of Private Electricity Provision in Southeast Asia*, WP 2001-02, at 22, The Wharton School, University of Pennsylvania (2001); and see also David Baughman and Matthew Buresch, *Mobilizing Private Capital for the Power Sector: Experience in Asia and Latin America*, Joint World Bank-USAID Discussion Paper (Nov. 1994) (discussing all aspects of the Pagbilao project and comparing it to similar projects in Chile, China, Colombia, Jamaica, Guatemala, Belize, and Pakistan).

<sup>71</sup> WORLD BANK, PRIVATE SOLUTIONS, at 24.

<sup>72</sup> Roxas, *supra* note 60, at 2.

<sup>73</sup> Withold J. Henisz and Bennet A. Zelner, *The Political Economy of Private Electricity Provision in Southeast Asia*, WP 2001-02, at 20, The Wharton School, University of Pennsylvania (2001).

<sup>74</sup> Under the EPIRA law, NPC no longer has authority to enter into contracts with IPPs.

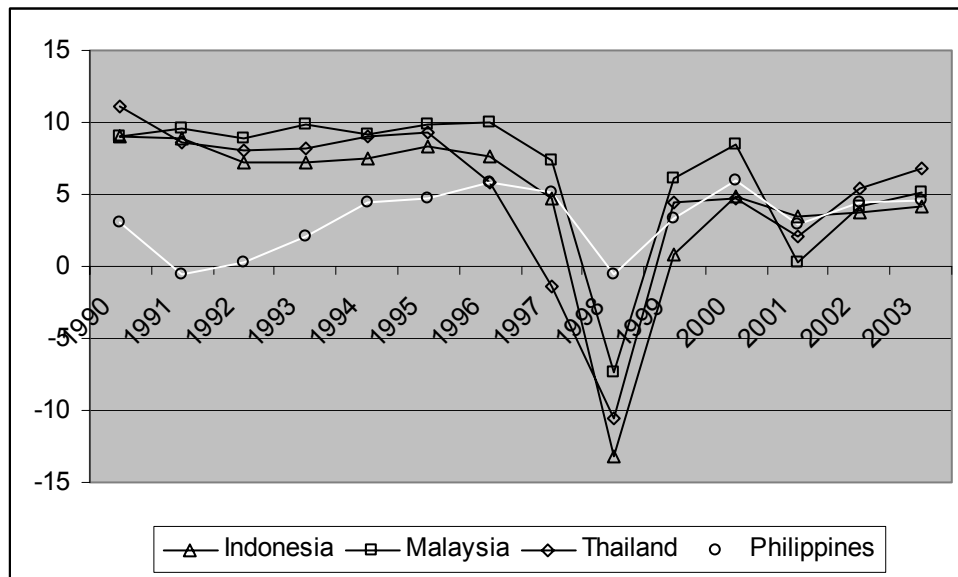
<sup>75</sup> Telephone Interview with Attorney, Hunton & Williams, April 5, 2004.

V. TURMOIL IN THE IPP SECTOR: THE ASIAN FINANCIAL CRISIS AND THE “RENEGOTIATION” OF THE IPP CONTRACTS

A. The Impact of the Asian Financial Crisis.

The Asian financial crisis did not affect the Philippines as suddenly or severely as its South-East Asian neighbors. During 1997 to 1999, major macroeconomic indicators declined severely, but not as steeply as in Indonesia, Malaysia or Thailand. Although not definitive, the following chart showing the change in GDP growth rates in the major South East Asian economies illustrates succinctly the relative impact of the crisis.

FIGURE 5: GDP GROWTH IN SELECTED SOUTH EAST ASIAN COUNTRIES



Source: *The World Bank, World Development Indicators 2005*

As illustrated in this chart, although the Philippine market was not impacted as severely as those in Indonesia, Malaysia, or Thailand, neither has it rebounded as those markets have. Rather, the Philippines continues to move along with growth rates of between 3-5% annually. Similarly, where the currencies of Malaysia and Thailand have rebounded somewhat from their mid-crisis lows, the Philippine Peso has continued its progressive decline in relation to the dollar. In the IPP sector, this results in a continued increase in the Peso cost of power from dollar-denominated IPP contracts. Thus, where the impact of the crisis on other South-East Asian countries was sudden and acute, in the Philippines the crisis introduced a new period of sustained decline.

This decline affected the IPP sector in two ways. First, because of a shortfall in electricity demand precisely when significant new capacity came on line, the electricity sector entered a period of excessive oversupply in the late 1990s. Constrained by the take-or-pay provisions of the IPP contracts, Napocor began paying higher unit prices for electricity as dispatch of plants sank to as low as 30-40%. Second, while recovering its IPP payments from a

dwindling number of kilowatt hours sold, Napocor also saw its IPP payments *increase* substantially due to the pesos' loss of value.

TABLE 3: NAPOCOR'S CAPACITY PAYMENTS TO IPPS

Year	Capacity Payments (million dollars)	Capacity Payments (million pesos)	IPP Capacity Online
1997	\$ 250.4	P 7,379.0	5,026MW
1998	\$ 269.1	P 11,004.0	5,516MW
1999	\$ 343.0	P 13,402.0	7,564MW
2000	\$ 529.8	P 23,412.0	7,717MW
2001	\$ 579.9	P 29,571.0	8,357MW
2002	\$ 632.5	P 32,640.0	10,197MW

Source: Myrna Velasco, *Surviving a Power Crisis* (2005), at 54.

Despite the serious impact of the crisis on the cost of electricity from the IPPs, equally significant pressure on Napocor's balance sheet flowed from political interference and regulatory uncertainty. The disastrous decline in Napocor's financial position reflected in Table 4, below, roughly corresponds with the devaluation of the peso during the same period. However, until about 1999-2000 Napocor was regularly passing through its IPP costs via the purchased power adjustment – meaning that much of this decline stemmed from increased payments on Napocor's own dollar-denominated debt.<sup>76</sup>

The IPP-related costs that landed on Napocor's doorstep came from two sources. First, political interference with the ERC's ratemaking authority. The current administration has not hesitated to use electricity prices as a political lever, twice mandating reductions in retail tariffs and limiting the costs Napocor passed through. The EPIRA law in 2001 imposed a 30 centavo reduction in electricity rates, and in July 2002, the Arroyo administration imposed a P0.40 cap on the amount of purchased power cost that NPC could pass through. The impact was disastrous – in the first 6 months of the PPA cap, the power firm had to borrow US\$500 million to cover its new artificial shortfall.<sup>77</sup> Second, Section 32 of the EPIRA law allowed NPC to recover the cost of power purchases from its IPPs for all of the contracts approved by the (then) ERB by Dec. 31, 2000. This deadline (for which there is no apparent explanation) excluded eight of the most expensive IPPs, including Ilijan, CBK, San Roque, and Casecnan, for which NPC must now absorb all costs. The impact of these decisions is illustrated in Figure 5. Prior to these events, Napocor had been rather fragile, due to the fact that it had long financed new investment almost entirely with foreign denominated debt rather than with equity contributions from government. By 2003, the power utility had been driven entirely into the ground, recording an operating loss for the first time in its history.<sup>78</sup>

TABLE 4: NAPOCOR'S DECLINING FINANCIAL PERFORMANCE

Year	Net Income (Loss)
1997	P 3,053
1998	(P 3,617)
1999	(P 5,953)
2000	(P 12,963)
2001	(P 10,377)
2002	(P 13,753)
2003	(P113,000)

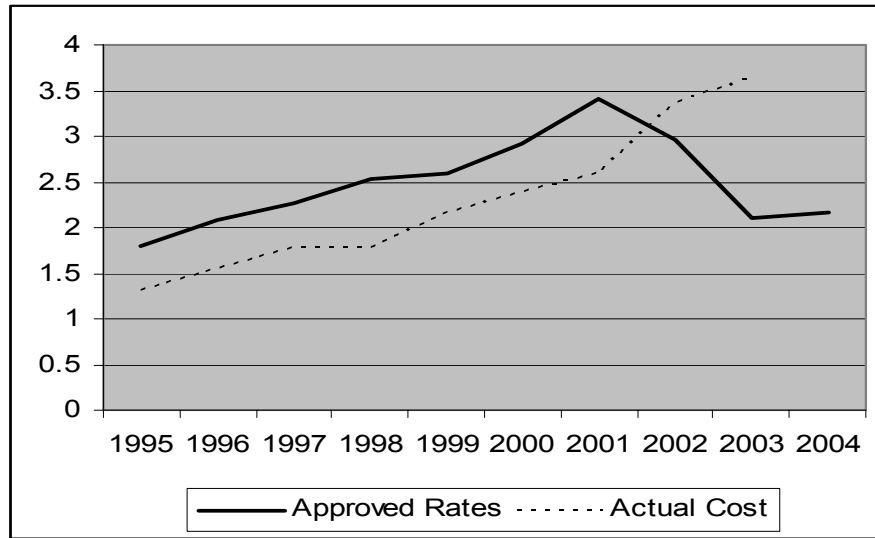
Source: Myrna Velasco, *Surviving a Power Crisis* (2005), at 109.

<sup>76</sup> In 2000, NPC had US\$6.6 billion in outstanding loan facilities, of which approximately 50% was US dollar-denominated and 45% was Japanese yen-denominated.

<sup>77</sup> MYRNA VELASCO, *SURVIVING A POWER CRISIS: THE PHILIPPINE EXPERIENCE* 100 (forthcoming 2005).

<sup>78</sup> A detailed account of this decline is provided in Edgardo del Fonso, *NPC's Financial Odyssey*, *Business World*, Oct. 18, 2004, at 25.

FIGURE 6: NAPOCOR'S ACTUAL COST VERSUS APPROVED RATES (PESOS/kWH)



Source: Adapted from Velasco (2005) at 142.

#### B. The Renegotiations.

Even in the face of distinct economic difficulty and intensifying political pressure, the Philippine government has been reluctant to renegotiate contracts. As pressure mounted for renegotiation, the government stopped short of real unilateral action, even though indications were that such renegotiations would unlock potentially up to US\$1 billion.<sup>79</sup>

The process began with the EPIRA law that required the appointment of an inter-agency commission (“IAC”) to review the IPP contracts, which by 2001 had become political and economically vulnerable. The law also mandated the unbundling of electricity rates in consumer bills.<sup>80</sup> This seemingly innocuous measure allowed Filipino citizens to see for the first time the precise costs that created some of the highest electricity rates in Asia. What they saw was that the power purchase adjustment that financed NPC’s PPA obligations with the IPPs was almost equal to the cost of the actual electricity consumed.<sup>81</sup> This inspired enormous political pressure against the IPPs, and drastically increased pressure on the IAC review of the IPP contracts. This review, completed in 2002, formed the basis for the renegotiations that followed.

The IAC was composed of representatives of the Department of Justice, the Department of Finance, and the National Economic Development Agency. There were no electric power industry government officials involved in the process, although the IAC did employ consultants to understand the complex contracts. The EPIRA law required the IAC to review the IPP

<sup>79</sup> VELASCO, supra note 77, at 100.

<sup>80</sup> Republic Act No. 9136, § 36 (Phil.)(2001).

<sup>81</sup> *The Philippines: the challenge of juggling market reform and expansion*, Energy Economist, Issue 266, at 15 (Dec. 2003). According to some accounts, some IPPs were paid to generate no electricity at all, Sheila Samonte-Pesayco and Luz Rimban, *Ramos Friends Got Best IPP Deals*, Philippine Center for Investigative Journalism (5-8 August 2002), at <http://www.pcij.org/stories/2002/ramos3.html>.

contracts for provisions that were “grossly disadvantageous, or onerous, to the Government.”<sup>82</sup> The report eventually produced roughly reflected this scope. The IAC, however, did not consult any of the project companies in the process.

The report that the IAC produced (“IAC Review”) covered a total 35 projects – all of Napocor’s operating contracts with IPPs. Of these, six were found to be clean and without any issue. The other 29 contracts were found to have issues of various kinds – legal, financial, or policy and were referred for renegotiation. Although the details of this report have been closely guarded by the Philippine government, some public details have been available. An account of the report was presented to the Philippine Congress, and identified several recurring themes in the review.<sup>83</sup> First, hydro power plants tend to be the most costly plants to the government.<sup>84</sup> Second, the IPPs with the biggest capacities or highest fuel costs accounted for most of the cost of undispached energy in the power purchase adjustment.<sup>85</sup> Further, many contracts had become unsustainable as a result of steep escalation clauses or extra-contractual amendment.<sup>86</sup> A media account of the IAC Review argued that undispached energy was a very common problem among IPPs contributing to the high price of energy.<sup>87</sup>

Upon completing the review, the IAC handed responsibility for implementing its findings to the Power Sector Assets and Liabilities Management Corporation (“PSALM”). PSALM is state owned corporation tasked with privatizing Napocor’s assets in the EPIRA regime, and is staffed by electricity sector experts, and former private sector bankers and lawyers. PSALM was mandated in the EPIRA law to implement the findings of the IAC Review and to “diligently seek to reduce stranded costs, if any.”<sup>88</sup> At the same time, PSALM is responsible for privatizing Napocor’s assets, and to “optimize the value and sale prices”<sup>89</sup> of Napocor’s assets in that process. The conflicting mandates to extract concessions from investors on the one hand, and to attract competitive bids from investors into the power market on the other hand, may have moderated PSALM’s approach to the renegotiation process.

PSALM announced the results of the IAC review in an all-hands meeting with the IPP companies. According to industry participants, investors initially greeted the renegotiation demand with powerful trepidation,<sup>90</sup> particularly as they eyed the recent and spectacular failures of IPP programs in Indonesia and Pakistan. PSALM proceeded with a lengthy consultation process in which senior officials met with project company executives to discuss the review, and possible room for reducing payments to the IPPs.

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<sup>82</sup> Republic Act No. 9136, § 68 (Phil.)(2001).

<sup>83</sup> *IPP contract review committee presents findings to lawmakers*, Energy Committee, House of Representatives, Republic of the Philippines, Aug. 21, 2002, available at [www.congress.gov.ph/committees/commnews\\_det.php?newsid=421](http://www.congress.gov.ph/committees/commnews_det.php?newsid=421).

<sup>84</sup> *Id.*

<sup>85</sup> *Id.*

<sup>86</sup> *Id.*

<sup>87</sup> Luz Rimban and Sheila Samonte-Pescayo, *Trail of Power Mess Leads to Ramos*, Philippine Center for Investigative Journalism, Aug. 5-8, 2002.

<sup>88</sup> Republic Act No. 9136, § 68 (Phil.)(2001).

<sup>89</sup> Republic Act No. 9136, § 51 (Phil.)(2001).

<sup>90</sup> *Philippine Government’s IPP Contract Renegotiation Plans Under Scrutiny*, Electric Utility Week (Aug. 19, 2002) (discussing fears of IPPs and businessmen over looming renegotiation threat).

PSALM began with the principal that the Philippines would not violate duly executed contracts. Thus, findings in the IAC Review that contracts were “expensive” or “onerous” were not seen as a basis for legal action or unilateral renegotiation. The organization also clarified that a finding of “legal issues” in a contract did not refer to defects in the validity of the contract, but rather to problems or disputes in interpretation or application of certain terms. As such, the much criticized “legal issues” were also not grounds for legal action. PSALM, in meeting with the IPPs, explored the possibilities of reducing Napocor’s liability under the relevant contracts, eventually settling on two principal avenues (others were considered but discarded during the consultation process). First, cost or fee reductions within the terms of the original contract – most commonly this was a collateral agreement by the project company not to nominate the full 105% or 110% that the contract allowed, or a clarification of ambiguous terms in a manner advantageous to the government. Second, a negotiated buy-out when the sponsor firms were interested in exiting the project – this eventually happened only in the case of the San Pascual project, discussed below. During the entire process the constraints imposed by lenders were perceived as forming a hard wall against unilateral renegotiation, and the importance of preserving the Philippines’ reputation in international markets was explicitly emphasized.<sup>91</sup>

This strategy led to striking results. First, in seven cases, PSALM decided that no action was required or possible. Second, because the process was managed under tight secrecy, the Philippine government essentially announced only the savings generated by securing concessions from the IPPs. An examination of the composition of these savings is equally revealing.

The majority of the savings were generated from five companies – Mirant, Marubeni (San Roque), Steag, ChevronTexaco/Edison, and CalEnergy. The largest share came from canceling the 300MW San Pascual project being developed by ChevronTexaco and Edison Mission Energy. This decision followed several years of delays, although no disputes have arisen, and both sides indicate

TABLE 5: SAVINGS FROM IPP CONTRACTS (IN US\$ MILLIONS)

Sponsor	Plant Names	Nominal Value	Present Value
Mirant	Sual, Pagbilao, Navotas I & II	377.20	165.64
Alsons	Iligan I & II, General Santos, Zamboanga	4.03	3.87
BHEPI	Binga	8.80	8.80
Aboitiz	Bakun, Benguet	9.60	4.07
SRPC	San Roque	239.50	146.72
Salcon	Naga	44.27	29.34
IMPESA/Edison	CBK Complex	92.57	68.78
SITI/STEAG	Mindanao Coal	887.31	182.46
CTX/EME	San Pascual	1,166.18	383.41
CalEnergy	Casecnan	112.11	38.36
KEPCO	Ilijan	7.59	5.29

publicly that the cancellation was mutual. Mirant, and many companies afterwards, provided concessions by agreeing to forego nomination of 105% of capacity as allowed in the original contract for the Pagbilao station. Over the life of the contract, this 5% of capacity would equal hundreds of millions of dollars in savings.

Most of the concessions that flowed from this “renegotiation” process were similar. However, in a few cases the government of the Philippines did exert more pressure, notably in

<sup>91</sup> This description of PSALM’s strategy has been adapted from a PSALM presentation to the House Energy Committee of the Philippine Congress, on May 7, 2003, and from conversations with industry participants in the Philippines in February 2005.

the three combination hydropower and irrigation projects – San Roque, CBK, and Casecan. Under pressure from the national government,<sup>92</sup> Meralco also initiated a parallel review of its IPP contracts that led to renegotiations with First Gas Power Corporation (the sponsor for the Santa Rita and San Lorenzo plants) and Quezon Power Philippines, Ltd. The completed renegotiations with First Gas resulted in Php0.03/kWh savings for consumers.<sup>93</sup>

Were the renegotiations unreasonable or unexpected? The 1994 World Bank study of the Philippine power sector noted that many of the criteria required under EO 215 to ensure sustainable development of the Philippine power sector had been ignored in the IPPs signed during the energy crisis up to that point.<sup>94</sup> The same report warned implicitly against the dangers of over-commitment to PPAs, a concern that became tangible when the most costly IPPs to the Philippine consumer were those with the largest capacity or most expensive fuel.<sup>95</sup> The fast track plants have also proven to be problematic in their own right, drawing sharp domestic criticism. Even ignoring the allegations of corruption that plague the Ramos Administration's IPP deals, the nature of the fast track projects (which utilized technology that had short construction lead times, low initial capital cost, but high operating costs) was such that it was clear at the time they would be inefficient suppliers once the generation sector caught up to demand—even though it would be better to dispatch these plants only peak generation or stand-by capacity, the terms of the PPAs would still require payment for the minimum off-take.

## VII. CONCLUSION.

The IPP experience in the Philippines presents starkly many of the common themes in the global IPP experience. The electricity sector reform, initiated in response to an electricity and investment crisis, began with the generation sector, and moved in fits and starts to a full blown reform. The IPPs succeeded in delivering power – in this case much needed power that ended a grave electricity shortage in record time.

However, the introduction of private generation into an only partially reformed electricity sector brought difficulties of its own. The IPPs have been a lightning rod for criticism of government policy, corruption, overpricing, and expensive energy. Against the backdrop of lower-than-expected electricity demand, rising foreign exchange liability, and state plants built with concessionary finance, non-transparent costs, and fluid offtake arrangements, the IPPs appear rigid, expensive and burdensome.

From the investor perspective, most of the IPPs operating in the country today are quietly satisfied with their experience. There have been hurdles, most notably the recent EPIRA inspired renegotiations. However, the eventual impact of these was either minimal, or was focused on those firms able to read some flexibility into their overnomination clause. The effectiveness of the government handling of the renegotiations, once handed off to PSALM, is a story that should be more widely known.

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<sup>92</sup> *Philippine Gov't Asks Meralco To Lower IPP Obligations*, Asia Pulse (Feb. 20, 2003).

<sup>93</sup> *Supreme Court Stops Meralco Rate Hike*, Philippine Daily Inquirer (Jan. 15, 2004).

<sup>94</sup> PHILIPPINES POWER SECTOR STUDY, at 18.

<sup>95</sup> *IPP contract review cttee presents findings to lawmakers*, *supra* note 83.

Negative experiences in the Philippines seem to flow from either poor contract structuring, as in two plants that sell to export-processing zones under contracts that accept fuel and market risk. This is not to say that the Philippine IPP experience has been an easy one for investors – every single project interviewed for this study recounted problems with various government counterparties, including Congress (which has a habit of calling IPPs to testify publicly on a regular basis). Most projects have been able to navigate this pressure successfully.

For the Philippines, the IPP experience has been a mixed one. On the positive side, the IPP program alleviated the severe shortages that devastated the island economy in the early 1990s. Terms for the contracts have become more competitive over time, and the decreasing reliance on sovereign performance undertakings to underwrite projects is a positive note. On the negative side, the IPP program has introduced power that is in some cases extremely expensive, and in all cases subject to firm and regular payments, into an electricity system with limited capacity to absorb this liability.

With more than a decade of experience with private power generation, the Philippines should be in a position to reap the benefits of extremely competitive contracting. However, the combination of the Asian financial crisis, re-politicization of electricity prices shortly thereafter, and the headlong leap into an ambitious reform program, has once again put the Philippines into a delicate position. Uncertainty in the new market structure has induced a gridlock for new investment, and investors’ perception of risk is high.

## VII. HYPOTHESES AND CASE SELECTION.

Consistent with the research protocol for the larger IPP study, the selection of cases within the IPP universe in the Philippines is designed to reflect variation along a number of critical variables. Before outlining these variables, however, it is important to note that the Philippines’ IPP experience does not exhibit the vast differences in outcomes that are seen in India (for example), where the spectacular failure of the Dabhol project is in stark contrast to the relative success of the GVK project. Rather, in the case of the Philippines, differences in outcomes must be gauged by examining more subtle measures, such as investor and government feedback, project technical performance, and the subtle contours of the investor-government relationship.

Thus, unlike some countries in our sample, the Philippines IPP sample does not suggest the dominance of certain variables in explaining outcomes. Rather, the more remarkable finding is the relative uniformity of treatment by the government of the IPPs, despite wide variation in the legal and political context, fuel type, location, size, government off-taker and investor mix. Given this context, the case studies of Philippine IPPs seek to capture the most important of these variables and map them onto the subtler differences in outcomes that characterize the Philippine history. Unfortunately, many of these outcomes will only become clear with in-depth research, so the case selection must rely on obtaining variation in the underlying factors that seem to characterize the sector, even if there is no strong *ex ante* correlation with outcomes.

The cases selected for introductory review are set forth below.

Project	Size	Fuel	Location	Regime	Gov’t party	Investors	IRC Result
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Quezon	440MW	Coal	Luzon	BOT II	MERALCO	F / D	---
Pagbilao	700MW	Coal	Luzon	BOT II	NPC	F	Rem. Financial
Ilijan	1200MW	Natural Gas	Luzon	Post-Asian	NPC	F	Financial
Navotas I-III	310MW	Diesel	Luzon	EO 215	NPC	F	Financial
Navotas IV	300 MW	Diesel	Luzon	Fast track	NPC	F	Clean
Subic	100MW	Diesel	Luzon	Fast track	NPC	F	Financial
Casacnan	140MW	Hydro	Luzon	BOT II	NPC	F / D	Legal/Financial

## Appendix A: Greenfield IPPs in the Philippines

Project Name	Local Investor	Foreign Investor	K	K Type	PPA Date	Finance Close	COD	Term	MW	Fuel	Off Taker
San Pascual	--	ChevronTexaco	BOO	PPA	Sep 97	2001	--	25	304	Oil/Nat Gas	NPC
Navotas I	--	Mirant	BOT	ECA	Feb 89	1991	1991	12	210	Oil (diesel)	NPC
Toledo	Atlas Con.	(CMS)	BOO	ECA	Apr 90	1994	1993	10	75	Coal	NPC
Pinamucan	--	Enron	BOT	ECA	Jun 92	1993	1993	10	105	Oil (bunker)	NPC
Mahiao	--	Cal Energy	BOT	ECA		1993	1993	13	119	Geotherm	PNOC
Iligan City II	Alsons	Tomen	BOT	ECA	Nov 92	1993	1993	12	40	Oil (bunker)	NPC
Iligan City I	Alsons	Tomen	BOT	ECA	Jun 92	1993	1993	10	58	Oil (bunker)	NPC
Calaca Batangas	--	FE Levingston (Sing.)	BOO	ECA	Jan 93	1993	1993	5	90	Coal	NPC
Limay Bataan	--	ABB, Marubeni, Alstom	BTO	ECA	Feb 92	1992	1993	15	600	Oil (diesel)	NPC
Benguet	Aboitiz	Pacific Hydro	BOO	PPA	Oct 91	1992	1993	25	22	Hydro	NPC
Bauang	First Gen	--	BOT	ECA	Jan 93	1994	1994	15	215	Oil (diesel)	NPC
Mindanao Barge	--	Mitsui	BTO	ECA	Feb 92	1994	1994	15	200	Oil (diesel)	NPC
Mahanagdong	--	Ormat, Marubeni	BOT	ECA		1994	1994	10	180	Geotherm	PNOC
Makban	--	Ormat	BTO	PPA	Feb 92	1994	1994	10	16	Geotherm	NPC
Bataan EPZA	--	Edison → Covanta	BOT	ECA	Oct 93	1994	1994	10	58	Oil (diesel)	NPC
North Harbor	--	FE Levingston (Sing.)	BOO	ECA	July 94	1994	1994	5	90	Diesel	NPC
Navotas IV	--	Hopewell → Mirant	BOT	ECA	Jun 92	1993	1994	12	100	Oil (diesel)	NPC
Subic	--	Enron	BOT	ECA	Jan 93	1993	1994	15	105	Oil (bunker)	NPC
Malitbog	--	Cal Energy	BOT	ECA		1995	1995	12	231	Geotherm	PNOC
Duracom Mobile	--	El Paso Energy	BOO	ECA		1995	1995	??	133	Oil (diesel)	Meralco
Cavite EPZA	Magellan	CMS → Covanta	BOO	ECA	Sep 93	1994	1995	10	63	Oil (diesel)	NPC
Quezon	PRM Power	InterGen, Covanta	BOO	PPA	Aug 94	1996	1996	29	440	Coal	Meralco
Leyte "A"	PNOC	--	BOT	PPA	Mar 94	1996	1996	25	200	Geotherm	NPC
Pagbilao	--	Hopewell → Mirant	BOT	ECA	Nov 91	1993	1996	25	700	Coal	NPC
Zamboanga	Alsons	Tomen	BOO	ECA	Jun 96	1997	1997	18	100	Oil (diesel)	NPC
Mindanao I	--	Oxbow, Marubeni	BOT	PPA	May 95	1995	1997	25	47	Geotherm	NPC
Leyte "B"	PNOC	--	BOT	PPA	May 94	1997	1998	25	440	Geotherm	NPC
General Santos	Alsons	Tomen	BOO	ECA	Mar 96	1995	1998	18	50	Oil (diesel)	NPC
Mindanao II	PNOC	Oxbow, Marubeni	BOT	PPA	Jun 98	1999	1999	25	48.25	Geotherm	NPC
Santa Rita	First Gen	British Gas Asia plc	BOO	PPA		1997	1999	25	1000	Nat'l Gas	Meralco
Sual Pangasinan	--	Hopewell → Mirant	BOT	ECA	Apr 94	1995	1999	25	1000	Coal	NPC
Panay	First Gen	--		Mch't		1998	2000	25	72	Oil (diesel)	Coop
Bakun	Aboitiz	PacificCorp, Pacific Hydro	BOT	PPA	Nov 96	1997	2000	25	65	Hydro	NPC
Paragua	--	Delta Corporation	BOT	PPA	1999	1999	2000	10	16	Oil (diesel)	NPC
CBK	--	IMPISA, Edison Mission	BROT	PPA	Nov 98	2000	2001	25	640	Hydro	NPC
Ilijan	--	KEPCO, Mirant, Kyushu	BOT	ECA	Nov 97	2000	2002	20	1200	Nat'l Gas	NPC
San Lorenzo	First Gen	British Gas Asia plc	BOO	PPA		2000	2002	25	500	Nat'l Gas	Meralco
Casecnan	30% local	Cal Energy, Peter Kiewit	BOT	PPA	Jun 95	1996	2001	20	140	Hydro	NIA
San Roque	--	Sithe, Marubeni	BOT	PPA	Oct 97	1998	2003	25	345	Hydro	NPC

# CEPA/Mirant in the Philippines

## A. Background.

Mirant entered the Philippines in 1997 (still as parent company Southern Energy), acquiring the Asian portfolio of Gordon Wu's Consolidated Electric Power Asia – including the Philippines projects, as well as Shajiao C in China, but conspicuously passing on the Tanjung Jati B project in Indonesia. Mirant remains the largest private generator in the Philippines, with interests in nine plants and a total of 2300MW of generating capacity. The Philippine portfolio was not included in Mirant's 2003 declaration of Chapter 11 bankruptcy.

In 1997, Southern acquired CEPAs assets in Asia, and soon spun off Mirant as the holding company for the firm's generating business. In the Philippines, the company's leadership remained the same as it had been since the 1988 signing of the Navotas contracts.

## B. Mirant's Philippines Business.

The portfolio of IPPs that were developed by CEPA/Mirant in the Philippines reflects almost the entire development of the IPP program there. This portfolio has included nine plants at various times. Here we focus on Mirant's major investments (projects of over 100MW), of which there are five.

TABLE 1: 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

**Navotas I and IV.** CEPA pioneered private generation in the Philippines, signing the first ECA under Executive Order 215 in 1988 for the Navotas I plant. This project came online in 1991, and was the only private plant to begin delivering power until 1993, when the country was deep into the power crisis and brought a number of smaller diesel fired units online. In 1991, with the electricity crisis looming, CEPA brought an additional unit online at Navotas (commonly referred to as either Navotas IV, because Navotas I had units 1-3, or Navotas II, because it was the second Navotas project). These projects had 10 and 12 year ECAs with Napocor and full performance undertakings from the Government of the Philippines. Designed as peaking facilities, these diesel-fired plants often ran as baseload during the crisis, before being throttled back in the late 1990s.

**Pagbilao.** In 1991 CEPA began three years of negotiations that culminated in the 1994 signing of another ECA for the 700MW Pagbilao coal-fired plant. Like Navotas I, Pagbilao was awarded through a bidding process—albeit with only two bids submitted. Pagbilao ushered in a series of large, baseload facilities (including CEPA’s next project, the 1000MW Sual plant). These projects started coming online as the Philippines was emerging from the power crisis and needed to add baseload capacity and stop firing expensive peaking plants all the time (such as Navotas). Like Navotas I before it, Pagbilao became a blueprint for future IPPs in the Philippines.<sup>96</sup>

<b>Pagbilao – Debt Structure</b>	
Citibank (arranger)	\$183 million*
Japan Ex-Im	\$220 million
Bank of Tokyo	\$147 million**
IFC	\$60 million (A loan)
IFC	\$11 million (B loan)
ADB	\$40 million
CDC	\$35 million
<b>Total</b>	<b>\$696 million</b>
* Political risk insurance from US Ex-Im	
** Guaranteed by MITI (95%), Mitsubishi (5%)	

So far as our research has indicated, this project has suffered only one major dispute. In 1996, although the plant had been constructed on time (and below cost), Napocor had not completed the transmission line to connect the plant to the grid, delaying commercial operations by several months. CEPA’s claim for lost revenue reached \$100 million before the dispute was resolved by extending the PPA by 4 years, from 25 to 29 years. Additionally, there have been some problems regarding the reliability of fuel delivery from Napocor,<sup>97</sup> but given the overall performance, these do not appear to be serious.

<b>Pagbilao – Project Equity</b>	
CEPA/Mirant	\$200M
IFC	\$10M
ADB	\$10M
CDC	\$10M
<b>Total</b>	<b>\$230M</b>

The financial performance of this project appears to be highly successful. Like many of the Philippines IPPs, project revenues were heavily concentrated in US dollar denominated capacity payments, in this case 95% of revenue was from capacity payments.<sup>98</sup> A recent IFC study of the project suggests a 17.5% internal rate of return over the life of the project, although acknowledges the possibility of much higher returns.<sup>99</sup> Given Mirant’s leveraging of the overnomination clause in the contracts for each of its plants, its additional sales via the marketing agreement with Napocor, and the remarkable profitability reported in the Philippine business press (*discussed below*), it is likely that actual returns have been higher than 17.5%.

**Sual Pangasinan.** The 1200MW Sual Pangasinan project continued CEPA’s development of coal-fired baseload capacity, and contributed to further diversifying the Philippines fuel mix away from expensive oil, towards domestic coal. Sual had only

<sup>96</sup> David Baughman and Matthew Buresch, *Mobilizing Private Capital for the Power Sector: Experience in Asia and Latin America*, Joint World Bank-USAID Discussion Paper (Nov. 1994).

<sup>97</sup> Global Private Power, Business Conference and Management Reports 2 (1995).

<sup>98</sup> Frank J. Lysy, *Case 1: Pagbilao Thermal Power Plant – The Philippines*, in RESULTS ON THE GROUND, INTERNATIONAL FINANCE CORPORATION (2001), at 15.

<sup>99</sup> *Id.*

1000MW under contract with NPC, and sold 200MW directly to large users pursuant to a joint marketing arrangement that shared profits with Napocor and Transco (which wheeled the power).

**Ilijan.** The 1200MW Ilijan plant was largely developed by Kepco, the Korean national utility, with Mirant holding only a 20% stake. The Ilijan plant is notable for several reasons. First, this project, along with First Gen’s Santa Rita and San Lorenzo projects, provided a marketable outlet for natural gas to flow from the offshore Malampaya field. Eager to develop further reserves of domestic fuel, the government pushed ahead with these projects, which came online between 1999 and 2002—a period when the Philippines was operating with overcapacity in its generation market. Ilijan was also one of the plants excluded from cost recovery under the EPIRA law because Napocor had not secured approval from the ERB by the December 31, 2000 deadline. The brunt of Ilijan’s capacity payments for 1200MW of natural gas fired power fell directly on Napocor’s balance sheet at a time of increasing fragility.

<b>Ilijan – Project Equity</b>	
KEPCO	51%
Mirant	20%
Mitsubishi	21%
Kyushu Electric	8%
<b>Total</b>	<b>\$215M</b>

At the same time, Ilijan represents in many ways the benefits that the Philippines reaped from a decade of experience with private power. The project was one of the most competitive plants in the country, with comparatively tight margins for the sponsors. At least part of the willingness of lenders to agree to a low tariff may have reflected growing awareness of the risks implied by continued reform efforts and the risks of renegotiation. The PPA, originally signed in 1997, was worked over in 2000 – at a time when the Philippines was already suffering from overcapacity and rising electricity prices from the peso’s devaluation. Sponsors and lenders at the time expressed the hope that this would help the terms of the ECA stand the test of time in a difficult market.

<b>Ilijan – Debt Structure</b>	
US Exim	\$150 million
Korea Exim	\$70 million
JBIC	\$225 million*
<b>Total</b>	<b>\$445 million</b>
* Commercial risk coverage from MITI (50%)	

These expectations seem to have been met. The IAC Review reviewed the project favorably on several fronts. Excluding fuel cost, the project was the 7<sup>th</sup> lowest cost IPP in levelized terms. 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. Kepco later paid an annual fee of \$800,000 to expand the coverage of this guarantee, another first. At the same time, Ilijan did contribute to the EPIRA renegotiation effort, agreeing to adjustments representing just over \$5 million in net present value. However, in a 1000MW plant with annual capacity payments of close to \$90 million annually<sup>100</sup> this seems a small adjustment.

<sup>100</sup> Based on author’s calculations.

Mirant has continued to acquire or build new projects. However, these have generally been smaller plants, far off the Luzon grid, selling to specific customers or cities. In the Philippines, with thousands of islands and at least three major unconnected grids, the power supply-demand situation varies dramatically all over the island. Mirant's plants serving particular customers in these areas have

C. Mirant in the IAC Review.

In the renegotiations following the EPIRA review, Mirant was the first company to settle with PSALM, and was one of the largest contributors to the NPV of the savings generated by the "renegotiations."<sup>101</sup> Indeed, after the Mirant deal was struck, several other IPPs followed suit, making deals along lines similar to Mirant's agreement.

In addition to leading the way, Mirant's agreement was emblematic of the EPIRA "renegotiation" process as a whole, in that the details of the agreement reflect a cooperative give-and-take.<sup>102</sup> Mirant agreed to forego the overcapacity nomination, in effect reducing by 5% or \$10 million the annual capacity charges. However, this energy (which was not getting dispatched anyway) could in turn be sold in the bilateral supply market to industrial offtakers. On the other hand, the definition of planned and unplanned outages was clarified in a way that reduced Mirant's exposure to penalty payments to Napocor.

On the other hand, the revenue loss from this agreement was not trivial – 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. However, the report continues to state that the settlement (which became effective in 2003) had no material financial impact on the contracts, implying that the overnomination capacity had not been included in the original pro forma projections for the plant.

D. Overall Performance.

Notwithstanding these developments, Mirant's Philippine assets appear to be quite profitable, generating revenues of roughly \$500 million annually from 2002-2004.<sup>103</sup> Mirant has consistently ranked among the most profitable companies in the Philippines, according to an annual ranking of companies based on their return on equity. In 2001 and 2002, Mirant was the top earning corporation in the country, and in 2003, Mirant subsidiaries occupied 3 of the top 10 spots. Both the Sual and the Pagbilao plants were criticized in the IAC Review for rapid payback periods, citing, for example, the fact that Pagbilao paid out 59% of Mirant's initial equity investment in its first four years of operations (1996-2000).

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<sup>101</sup> Mirant's agreement with PSALM became effective in March 2003. Mirant Corporation, 2004 10-K at 16.

<sup>102</sup> Details adapted from media accounts and from Mirant Press Release, *Mirant and Philippine Government Agencies Reach Mutually Beneficial Agreement*, October 28, 2002, available at [www.mirant.com](http://www.mirant.com).

<sup>103</sup> 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.").

From the perspective of the Philippines, the evolution of the CEPA/Mirant portfolio of IPPs illustrates the larger development of the IPP program generally. The Navotas projects, intended to address the immediate electricity crisis, became quickly obsolete when larger baseload coal and hydro plants entered the Luzon grid in the mid-1990s, explaining the low utilization rates of these plants for the rest of the decade. By the time of the IAC review Navotas was on economic shutdown – available to supply power, but not dispatching. While costly, the need to address the power crisis was critical, and the shorter contracts and demonstration effects for private investment in the Philippines mitigated the cost of paying for this capacity.

As discussed earlier, the Pagbilao and Sual 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 a long climb. Pagbilao, in particular, opened the door for substantial financing later in the decade.

TABLE 2: PLANT FACTOR FOR MIRANT’S PHILIPPINES IPPS

Plant	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Navotas I	33.89	45.8	53.6	30.7	7.27	3.33	2.37	3.59	0.57	1.01	1.85	0.82	0	-
Navotas II	-	-	60.68	48.85	16.91	6.27	5.07	6.52	0.96	1.93	3.05	1.64	0.4	0.03
Pagbilao	-	-	-	-	-	63.3	65.76	67.11	62.62	61.65	55.91	39.13	39.41	33.79
Sual	-	-	-	-	-	-	-	-	72.1	58.17	61.04	53.21	45.23	51.43
Ilijan	-	-	-	-	-	-	-	-	-	-	-	N/a	*40.46	*36.54

Source: Mirant (Philippines) Corp.

“n/a” = information not available. “\*” = estimated value

On the other hand, the low utilization rates of these plants (set forth in Table 2, above) are of some concern. While difficult to prove, we speculate that this reflects a common complaint of private generators in the Philippines – that NPC was unable to discipline its dispatch rules, and failed to retire old, inefficient and dirty plants according to schedule in the late 1990s. Mirant officials suggest that the utilization rate of the plants was also adversely affected by the coming online of the gas-fired facilities from 2000 to 2003 (which the government had pushed in order to provide a market that would justify development of the Malampaya gas field), and by transmission constraints in the Batangas area. As such, while the presence of IPPs, with firm payments and dollar denominated contracts, exacerbated the financial woes of Napocor in the late 1990s, the problem at its root was likely related to larger impediments in the Philippine electricity sector.

More recent calculations based on records maintained by the ERC suggest, however, that this problem is improving. While in 2001 all three plants continued with low utilization, in 2002 each of Sual, Pagbilao and Ilijan dispatched all of the electricity for which Napocor had been billed, suggesting utilization at least covering the minimum offtake provisions. Mirant officials report that this trend has continued to improve through 2005.

## Quezon Private Power, Limited The Philippines

Specifications			
<b>Capacity</b>	440MW	<b>MOU</b>	1993
<b>Fuel</b>	Coal ( <i>imported</i> )	<b>PPA</b>	1994
<b>Technology</b>	Pulverized Coal Boiler	<b>Financial Close</b>	1997
	Steam turbine	<b>COD</b>	2000
<b>Actual Cost</b>	\$895.4 million		
<b>Debt:Equity</b>	75:25	<b>PPA Term</b>	25 years
		<b>Ownership</b>	BOO
<b>Sponsors</b>	PRM Power (2%), Intergen (72%) <sup>104</sup> , Covanta (26%)		
<b>EPC Contractor</b>	Bechtel Overseas Corporation		
<b>Operator</b>	Covanta Energy		
<b>Multilateral involvement</b>	US Export-Import Bank, OPIC		
<b>Offtaker</b>	Meralco		
<b>Lenders</b>	US Ex-Im, OPIC, UBS (arranger), US Public Bonds		

### I. PROJECT STRUCTURE.

#### A. Facilities.

The Quezon plant is currently a 460MW coal-fired facility on a 100 hectare site on the east coast of Luzon in the Philippines. The project is connected to the national grid via a 31-kilometer transmission line built and owned by the project sponsors.<sup>105</sup> The plant uses standard coal-fired steam generator technology and has been outfitted with extensive emissions abatement equipment.

#### B. Stakeholders and Project Company.

The Quezon plant is owned by Quezon Power Philippines, Limited (“QPPL”). The original shareholders in QPPL were PMR Power, Ogden (later Covanta), and Intergen. PMR Power negotiated the original arrangements with Meralco embodied in an MOU signed in 1993. Ogden entered via a competitive tender to be lead developer on the project and subsequently brought in Bechtel Enterprises (later Bechtel’s joint venture with Royal Dutch Shell, Intergen) as a co-developer. In the end, QPPL was formed as a limited partnership in which PMR Power held 2%, Intergen held 71.85% (of which 25% was held by GE Capital), and Ogden held 26.125%.

<sup>104</sup> Intergen sold a 25% interest to Global Power Investors at financial close. GE Capital eventually bought out GPI and currently owns the stake. Intergen’s share was purchased in early 2005 by a joint venture of Ontario Teachers and AIG.

<sup>105</sup> The 31-km transmission line necessary to connect the plant to the national grid runs through hundreds of small land-holdings with over 1,000 land-owners. The QPPL employed a team of lawyers to negotiate and/or handle proceedings to resolve each case.

The EPC contractor for the project was Bechtel Overseas Corporation. The project was constructed under a lump sum turnkey Engineering, Procurement and Construction Management contract (“EPCM”) to facilitate financing with non-recourse debt. Equipment sourcing was concentrated with US vendors (GE, Foster Wheeler) in order to maximize the use of export credit finance from US Exim. The O&M contractor for the project is Covanta. Operations and maintenance is performed on a cost plus basis pursuant to a 25-year agreement providing a monthly fee of \$160,000 as of the commercial operations date. The project is managed by Intergen under a 25-year management services agreement providing an annual fee of approximately \$400,000 as of the commercial operations date.<sup>106</sup>

#### C. Power Sale Arrangements.

Quezon sells its entire electricity output to Meralco via a 25-year PPA. The contract is denominated primarily in US dollars although there is a portion of the O&M fees payable in pesos. Unlike most of the other IPPs in the Philippines, the financing for this project was closed with no sovereign undertaking to guarantee the power purchase obligations of the offtaker. Quezon was the first large-scale IPP in the Philippines without a sovereign guarantee and was the first IPP selling its output directly to Meralco.

The tariff is comprised of capacity payments, O&M payments and energy payments. The capacity payments include the return of and on debt and equity capital required to finance the project. O&M payments cover both fixed and variable costs of running the plant. A component of the fixed O&M charges is also accumulated over several years to fund periodic major maintenance overhauls necessary to keep the plant in proper condition. The energy payment covers the cost of coal consumed in the actual production of electricity and is billed through to Meralco at actual CIF cost. Quezon was designed to run as a baseload plant, and the PPA specifies a minimum energy offtake by Meralco of 100% of Quezon’s output (*the application of the minimum offtake provision has been subject to some dispute – see discussion below*).

#### D. Fuel Supply.

Fuel supply for Quezon is provided for in two overlapping fuel contracts with Indonesian coal companies – P.T. Adaro and P.T. Kaltim Prima. The contracts are for 25 years. Quezon receives 150,000 tons of coal per month, and operates with a 40-60 day reserve of coal on-site. The coal is clean by international standards. The fuel supply agreements have been relatively free from controversy. The project was successful in negotiating a reduction in the amount of coal delivered in 2003, without penalty from the supplier, because the plant was not being dispatched at full capacity. Currently, Quezon is renegotiating its fuel price indexation arrangements with its coal suppliers.

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<sup>106</sup> Robert E. Kennedy, *InterGen and the Quezon Power Project: Building Infrastructure in Emerging Markets*, Harvard Business School Case Study 9-799-057 (2002), at 8.

E. Financing Arrangements.

Total project cost for Quezon was approximately \$810 million. The plant was financed on a non-recourse project basis, securing debt finance from a variety of sources. Fieldstone Private Capital acted as sole financial advisor and arranged all of the political risk cover required by the foreign lenders. Political risk cover was provided by US Export-Import Bank (“US Exim”) (approximately \$385 million) under a standard OECD guideline facility and OPIC provided insurance of approximately \$200 million. Once the political risk cover was in place, Fieldstone organized a competitive tender among 18 international banks for the underwriting of the debt funding. UBS was awarded the \$600 million underwriting of the commercial facilities, and Fieldstone assisted UBS in placing over \$100mm of dollar denominated debt in the Philippine market to fund a contingency reserve and working capital facility.

The domestic market loan was fully underwritten by Far East Bank—the largest underwriting ever by a single bank in the Philippine market. After financial closing, Quezon retained Salomon Brothers, Citibank and Fieldstone to place \$215 million of public bonds in the US capital market. The proceeds were used in lieu of the OPIC facility, a portion of which was later converted to political risk cover for the equity investors. The bonds had an average life of 15 years with a final maturity of 20 years.

Quezon was the first IPP in the Philippines financed solely on the basis of the credit of a private off-taker—Meralco. Usually, private power projects in the Philippines sell their energy to Napocor, whose performance (payment for the contracted energy) is guaranteed by the government. In this case, Quezon Power was able to secure financing based solely on the solid credit and financial position of Meralco, without any government guarantee.

F. Environmental and Social Investment.

Quezon Power designed and implemented an environmental program that went well beyond the industry standard<sup>107</sup> and provided a team to work for the Philippines government in monitoring compliance with the terms of the environmental program. This has not avoided controversy entirely, but has minimized environmental concerns usually associated with coal-fired plants. As part of this program, the plant installed extensive emissions abatement equipment to reduce harmful emissions.

Additionally, Quezon engaged in extensive community consultation that resulted in the implementation of a range of local community development projects, including job training, scholarship programs, medical clinics, road and water service improvements and local electricity. The community development program was designed to provide both procedural and substantive satisfaction to the local community, on the one hand involving

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<sup>107</sup> Michael T. Burr, *The new models*, INDEPENDENT ENERGY, June, 1998, at 18 (presenting the Quezon plant as one of a small group of innovative infrastructure deals from 1998, when the project was completed, and highlighting the community investment and environmental standards).

local leaders in actually designing the program to address specific needs and priorities, and on the other hand delivering continuing and tangible benefits to the community.

G. Other Risks and Considerations.

The region of the Philippines that played host to the generation facility also happened to be surrounded by pockets of active rebel activity. Faced with the national government's limited ability to provide security, the project decided that it had to take matters into its own hands, and contacted the rebels through local interlocutors to initiate a negotiation process. The rebels' main interest seemed to be in imposing a tax on the operation, an arrangement that would have been impossible for either Quezon Power or the national government to accept. However, according to project officials and others involved in the development phase, this risk was largely eliminated by fostering a positive relationship with the local population through environmental programs and community investment and consultation. Once the Quezon developers had won the confidence of the local population of neighboring Mauban, the rebels had little leverage or support to apply aggressive pressure on the project. By all indications, the relationship with the local community remains strong, and since operations the project has faced no significant challenges from the rebels.

II. HOST COUNTRY CONTEXT: THE PHILIPPINES IPP PROGRAM.

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 the 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, the entrance 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.

During the development of the Quezon Project, the Philippines was experiencing robust electricity demand growth that was expected to continue throughout the decade. However, the financial closing of the bond placement occurred one day before the Thai baht devaluation that signaled the beginning of the Asian financial crisis and depressed electricity demand in the Philippines for several years. By 2000, when the Quezon plant achieved commercial operations, the Philippines was facing an electricity oversupply. Additionally, the impact of the crisis had focused public attention on the IPPs, and accusations of price gauging and corruption became common.

For more information on the host country context, see Erik J. Woodhouse, *The Philippines Electricity Market Investment Context*, PESD Working Paper #39 (April 2005), available at <http://pesd.stanford.edu>.

### III. DISPUTES AND CHALLENGES.

The Quezon project has faced a number of challenges that are typical of the developing country power sector investment context. Despite these challenges, the project has performed relatively well financially for its sponsors.

#### A. Meralco's Rate Refund.

First, the project's sole offtaker, Meralco, has been involved in a series of disputes with the courts and electricity regulatory authorities in the Philippines that have at times eroded the distribution company's financial position. In late 2002, the Supreme Court prohibited Meralco from including in its rate base income tax and ordered a refund to customers amounting to more than \$500 million dollars. This, and other disputes between Meralco and the courts and regulatory authorities in the Philippines have negatively affected the solvency of the distribution utility, increasing the risk of payment problems towards its IPPs, including Quezon. To date, this risk has not materialized, although other disputes have affected Meralco's payments to Quezon.

#### B. Transmission Line Costs.

NPC delayed commissioning of the plant for several months, imposing substantial costs on the project sponsors, including more than \$25 million that had to be paid to the EPCM contractor for costs of delay. While this figure was included in the recoverable cost of the transmission line, the regulator, in a decision issued in 2004, ruled that this cost should be recovered directly from Napocor and not the ratepayer. The ERB (now ERC) refused to allow Meralco to pass these costs through until Meralco could justify these expenses.

Quezon agreed to temporarily suspend payment of this portion of the transmission line charge until the matter could be resolved with the ERC. Some time later, however, the ERC revisited the case and allowed the pass-through to proceed except for a portion equivalent to approximately 30% of the transmission line charge (roughly \$28.6 million).<sup>108</sup> According to project sponsors, the disallowed portion of the Quezon transmission line charge is still being discussed with Meralco. Although this state of affairs constitutes a technical default under Quezon's loan documents, the project secured permission from its lenders to waive this non-payment.<sup>109</sup>

#### C. Technical Performance.

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<sup>108</sup> Myrna M. Velasco, *Meralco allowed recovery charge*, MANILA BULLETIN, Oct. 26, 2004.

<sup>109</sup> Covanta Energy, Form 10-K (2004), at F-30.

During the early years of operations, the plant had trouble generating at its contracted capacity. This upset Meralco, which was unable to dispatch power when necessary. Additionally, under the original contract, Meralco was obligated to make full fixed operating payments even if the plant was unavailable. Unhappy with this state of affairs, in June 2001, Meralco began withholding payment for unavailable capacity. Meanwhile, the board of Quezon Private Power, Ltd. was having trouble taking decisive action to resolve the operator performance issues because the board seats were evenly divided between its shareholders.

This dispute with Meralco was resolved by renegotiating the PPA to eliminate any obligation to pay for capacity if the plant was unavailable due to the plant's fault (which was important to Meralco), and by clarifying the application of the take-or-pay requirements (which was important to Quezon) to specify that Meralco must take all contracted energy that is available from Quezon. The technical difficulties facing the plant were eventually resolved. During substantial portions of time when these various disputes were being resolved, US Exim forced the project sponsors to suspend dividend payments.

#### IV. PROJECT OUTCOMES: QUEZON PRIVATE POWER.

##### A. Outcomes for Investors.

The Quezon plant seems to be a reasonable success for the investors. Intergen itself realized some profit in the 1997 sale of a 26% interest to Global Power Investments, which generated a 12% profit. Original models by Intergen called for a 23% IRR for equity in the project.<sup>110</sup> Intergen sold its interest in the project in 2005 for an undisclosed amount. Both InterGen and Covanta are paid under Management and Operating contracts, respectively. PMR is a passive investor at this point, but continues to draw equity returns on a 2% share.

While the project has endured periods of technical default under the loan documents, due to non-payment by Meralco, available information suggests that loan service has been uninterrupted. The PPA has been renegotiated at various times, although the agreement reached pursuant to Meralco's parallel review of its own contracts that followed the NPC review has yet to be approved by the ERC. Bilateral renegotiations between Meralco and Quezon served to clarify items that were important to both sides, and were mutually beneficial.

##### B. Outcomes for the Philippines.

From the host country perspective, the Quezon project also seems to have met reasonable expectations. The project structure constituted a leap forward in the Philippines IPP market in terms of privatizing risk – with no guarantee, and no direct government involvement other than a wheeling agreement with NPC, the Quezon project

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<sup>110</sup> Robert E. Kennedy, *InterGen and the Quezon Power Project: Building Infrastructure in Emerging Markets*, Harvard Business School Case Study 9-799-057 (2002), at 11.

has delivered electricity at no cost or risk to the Philippine government. As such, the success, or at least stability, of the Quezon project will illustrate the viability of IPP financing without sovereign guarantees—which is both desirable for all developing countries, and necessary (the Philippines can't afford to guarantee its entire generating capacity, and the EPIRA law prevents NPC from entering into any further contracts with IPPs).

Additionally, the project's environmental performance is strong, at least for a coal plant, and the local community has benefited from increased tax revenues, employment and community programs sponsored by the project company.

Additionally, most of the fixed costs associated with Quezon are structured to remain relatively flat over time, delivering improving returns to Meralco and to the Philippines. The capacity fee is fixed for the life of the contract. Quezon Power, as part of its project structure, was required to secure coal through long term contracts at fixed prices. Given the significant increase in spot coal prices in Asia, project sponsors report that Quezon's coal costs are now approximately 30% below the spot market.

## CalEnergy’s Casecan Multipurpose Hydro Project<sup>111</sup>

CalEnergy (since acquired by Mid-American Holdings) has been operating in the Philippines IPP market since the early 1990s, and has developed three projects – one large combination hydro project and two geothermal plants. The two geothermal plants – Mahiao and Malibog – were CalEnergy’s first projects in the Philippines. Disagreements with primary offtaker PNOC were arbitrated in the late 1990s, resulting in decisions favorable to CalEnergy. Since the litigation, the geothermal projects have been operating consistently and our research has uncovered no signs of disputes or any other problems.

The large hydro plant – Casecan – has been somewhat more controversial. This BOT project was one of the rare unsolicited project among IPPs in the Philippines, and was designated a “high-priority project” by NEDA. Project development began when the original PPA was signed in 1994 between NIA and CalEnergy, followed by financial close in 1995 (on the 144A notes, see below). The project did not come online until 2001, due in part to a dispute with the original EPC contractor, Hanbo of Korea.

Casecan was developed by CalEnergy, in cooperation with Peter Kiewit Sons, Ltd., which together held 70% of project equity, and two local partners, LA Prairie Group Contractors and San Lorenzo Ruiz Builders and Developers, with together held 30% of project equity, but do not appear to have been substantially involved in the development of the project. In 1997, CalEnergy acquired Peter Kiewit’s interest in Casecan (along with their interest in several other joint ventures in the Philippines and Indonesia).

Project details include 140MW of electricity as well as irrigation water to be delivered to NIA (which on-sells the electricity to Napocor). NIA’s obligations under the PPA are backed by a full performance undertaking from the Philippine Central Bank. Power sales arrangements call for NIA to purchase 100% of the power actually generated by the plant, on a take-or-pay basis. Capacity payments, which are entirely denominated in US dollars, amount to roughly 70% of project revenue, while energy payments were expected to contribute the remaining 30%.

Total project cost is estimated at \$495 million. Casecan was financed on a project basis, with \$371.5 million of debt being raised in the 144A bond market, to complement \$124 million of equity contribution.

Casecan – Capital Structure	
144A Notes – Tranche A	\$75M, 7 years, floating
144A Notes – Tranche B	\$125M, 10 years, fixed
144A Notes – Tranche C	\$171.5M, 15 years, fixed
Equity	\$124 million
Total	\$495.5 million

The project’s original EPC contractor, Hanbo of Korea, declared bankruptcy in its home market and withdrew from the project. CalEnergy signed a new EPC contract with a consortium of firms and pursued a claim against Hanbo. Several reports indicate that Casecan came in significantly over budget,<sup>112</sup> but we have not been able to verify this.

<sup>111</sup> *Primary Sources*: CalEnergy 10-K Annual Report, SEC Filing (available on EDGAR); Inter-Agency Committee on the Review of the 35 NPC-Independent Power Producers (IPP) Contracts, Final Report (5 July, 2002).

<sup>112</sup> *See, e.g., Casecan Completion*, International Water Power and Dam (Oct. 31, 2001)(indicating a final cost of \$645 million for the project).

Trouble with NIA began to brew with a dispute regarding an arrangement whereby CE Casecnan was to pay certain taxes on behalf of NIA, who was in turn to reimburse these payments either directly or via an increased energy charge. NIA quickly refused to make direct payments, and reduced energy payments by the amount of the tax refund. As this controversy was beginning to expand, the IAC Review arrived, raising the political heat considerably.

Scheduled to come on stream in 2002, the Casecnan project lacked any operating history when it was evaluated in the IAC Review. However, the report found that the plant had the highest levelized cost of any IPP and that the guaranteed 801.9 million m<sup>3</sup>/year of irrigation water made no sense because the rivers did not deliver that much water. For their part, CE Casecnan had been frustrated by NIA's refusal to reimburse the costs of taxes paid by the company on behalf of NIA and reimbursable under the contract arrangements. CE Casecnan filed a notice of arbitration before the ICC in August 2002.

The resolution of these issues was laid out in a supplemental agreement to the BOT contract. Under this settlement, NIA paid to CE Casecnan \$117.6 million, and CE Casecnan paid to NIA \$1.6 million (for late completion) and to the Philippines tax authority \$24.4 million. The hydrology risk was settled by providing credits to NIA for water delivery below 801.9 m<sup>3</sup>/year that were redeemable against future water delivery payments beginning in 2008. An additional dispute regarding the escalation of excess energy payments was resolved by reversing the escalation and adopting a declining tariff for excess energy delivery.