IPP Study Case Selection and Project Outcomes: An Additional Note

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

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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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During 2004-06, the Program on Energy & Sustainable Development undertook a study of the experience of independent power producers ("IPPs") in developing countries. As part of the study, the Program sponsored a series of country studies. These papers detail the basic contours of the IPP experience in each country and discuss the country factors identified in the research protocol. Additionally, each paper presents the universe of greenfield IPPs in the country, identifies the significant characteristics across which these projects vary, and selects a small number for individual examination.[1]

This paper summarizes the experiences of the countries and projects that were part of the IPP study. Additionally, the paper provides a concise statement of project outcomes and a brief statement of the rationale underlying the analysis of each project. In doing so, the paper aims to gather in one place the disparate outcomes that are discussed in a long series of working papers, thereby providing a transparent and accessible document that will facilitate further study and critique of the original coding for the study, as well as of the analysis of projects and countries.

In the IPP study, each project is examined for investment outcomes and development outcomes. The projects are rated **positive**, **mixed**, or **negative**, for each set of outcomes. The purpose of this paper is not to set forth a full evaluation; it aims only to announce results and explain the principle factors considered in determining the outcomes for each project. More detailed consideration can be found in the individual country studies, and the global analysis is set forth in the final IPP study report available on the PESD website.

The examination of projects in each country varies in the level of detail. Generally, the most detailed work was conducted in Brazil, China, Egypt, India, Kenya, the Philippines, Tanzania and Thailand—countries in which field research was conducted. In these cases, a wide array of locally available sources of information, including local media and government records, and interviews with investors, project advisors and government officials, have been gathered.

In other cases—Argentina, Malaysia, Mexico, Turkey, and Poland—media and scholarly sources of information are relied upon, and are supported by stakeholder interviews where possible. In these cases available information may be limited. Additionally, several projects that are involved in ongoing disputes are covered. In these cases, where relations between government officials and project stakeholders may be very sensitive, the treatment in the IPP study is limited. Some of these studies may be updated if and when disputes are resolved.

[1] The research protocol for the IPP study, as well as individual country studies authored by PESD researchers, are available at http://pesd.stanford.edu/ipps. The conclusions of the study are reported at Erik J. Woodhouse, *The Obsolescing Bargain Redux? Foreign Direct Investment in the Electric Power Sector in Developing Countries*, 38 N.Y.U. J. INT'L L. & POL. XX (forthcoming 2006)

1. ARGENTINA.

Argentina privatized its electricity system in 1992, in one of the most successful reform efforts in the developing world, with generation, transmission and distribution unbundling and passing to private ownership. From 1992-2002, a private and fragmented generation market competed to sell electricity in a spot market in which the wholesale price of electricity declined from (US) $41/megawatt-hour in 1992 to $22/megawatt-hour in 1995, and average thermal power plant availability improved from 48 percent to nearly 70 percent. During this time there were 45 private power plants in Argentina, of which roughly 15 were greenfield projects, including both hydro and thermal (mostly natural gas) plants.

In 2002, Argentina faced a severe macroeconomic and political crisis, which reached a dramatic crescendo in January 2002, when the government abandoned the 10-year currency board that had pegged the peso to the dollar at 1:1. Subsequently, the government converted all infrastructure contracts to pesos, inviting an ongoing dispute with investors who faced a dramatic erosion in revenues. Almost thirty arbitration claims were filed against Argentina (from all sectors). The private generation sector continues to sell electricity, and the two sides weave (or stumble) their way to a settlement.

No in-depth project studies were undertaken in Argentina. The determinants of outcomes for IPPs in Argentina are predominantly country-level factors, including the macroeconomic crisis of 2001-02. Most projects have faced the same challenges. Some variation has been reported from local IPP investors converting debt to pesos prior to the crisis, which would allow them to weather the troubles relatively undisturbed.

2. BRAZIL.

Brazil followed the example set by Argentina and Chile, embarking on an ambitious reform of its electricity sector in 1994. With strong intial interest, most of the distribution assets in the country were sold via auction to private companies. Subsequently, however, the privatization ground to a halt due to lack of investor interest and political opposition, leaving most of the generation sector under state control. Between 1996 and 2003, generators operated in a multi-buyer, multi-seller environment, dominated by bilateral contracts between generators (public and private) and either distribution companies or large users. In 2003, the administration of President Luiz Inacio Lula da Silva announced a new model law for the wholesale electricity markets. This new model segregates the market into a regulated (distribution companies selling to captive consumers) and free (large users) segments. Sales to the regulated market can only be made via managed auctions at regular intervals prior to delivery of electricity. The new model has yet to reach full operations—the first auction for new capacity was scheduled for November 2005, but was postponed.

In addition to the halting progress of privatization and uncertain reform agenda, the major challenge has been to attract investment in thermal capacity in an electricity system dominated by hydro plants. Facing an energy shortage in the late 1990s, Brazil was forced to offer generous concessions to thermal IPPs. In Brazil's merit order dispatch system based on short-run marginal cost these plants suffered from poor utilization, and government entities that had been enlisted to provide support (notably Petrobras, the state oil and gas monopoly) became increasingly restive. Several arbitrations have arisen from thermal plants facing non-performance from key government counterparties or from consumers unhappy with the high cost of inflexible thermal projects.

Project selection in Brazil reflects two key variables. The first is fuel choice; in a hydro dominant system, it is important to select both thermal and hydro projects. The study examines a range of thermal projects (Termoceará, Norte Fluminense, Uruguaiana), and one hydro project (Caña Brava) (the limited selection of hydro projects is discussed below). The second is the choice of offtaker and power sales arrangements; for thermal projects, special arrangements to attract investment included quasi-merchant projects with revenue guarantees (Termoceará), sales to state distribution companies (Uruguaiana) and pass-through arrangements with associated distribution companies (Norte Fluminense).

2.1. *Termoceará*. Termoceará is a 290MW natural gas-fired power plant in northern Brazil, near the city of Fortaleza, developed by MDU Resources, a United States utility, and EPX Capital, a Brazilian industrial firm. The plant was built on a quasi-merchant basis, intending to sell electricity in via the spot market and short-term contracts, but with a minimum revenue guarantee from Petrobras, which functions like a capacity payment, covering fixed costs and some return on equity. The project was constructed by its sponsors on balance sheet. After commercial operations, corporate financing was obtained from United States Export-Import Bank and BNDES.

Originally developed during the electricity shortage of 2001-02 when spot prices were around \$600/kWh, Termoceará reached commercial operations in late 2002, when spot prices had dropped to \$18/kWh. In addition to low prices, the increasing scarcity of gas became a principal problem for Termoceará; the gas shortage was exacerbated by transmission bottlenecks that failed to meet demand when two gas-fired projects in the region (the other was Endesa's Termofortaleza) were dispatched at high levels.

Since 2002, project sponsors have been engaged in an ongoing dispute with Petrobras, which was losing substantial amounts of money covering the minimum revenue guarantee. On January 13, 2005, Petrobras obtained an order in Brazilian court providing for the deposit of monthly capacity payments into a court account until the dispute was resolved. MPX successfully litigated this decision and secured a reversal in trial court and on appeal. The project was sold to Petrobras in mid-2005 for \$137 million (including the total assumption of indebtedness); original project cost was \$100.

We rate <u>investment outcomes</u> for Termoceará to be **mixed**. The project faced a difficult operating environment, sold little electricity, and weathered a contentious dispute with Petrobras. Nonetheless, the minimum revenue guarantee was paid for three years, and the buyout price suggests a modest profit. We rate <u>development outcomes</u> for

Termoceará to be **negative** in the short term, although they may improve with time. The lack of gas and adverse market conditions for gas-fired power in Brazil rendered the project essentially an expensive experiment with little upside. Nonetheless, as Brazil's gas markets mature, the project may prove to be highly valuable.

2.2. *Norte Fluminense*. Electricité de France's ("EdF") Norte Fluminense project is one of four natural-gas fired "self-dealing" projects developed in Brazil. The 780 megawatt power plant sells all of its electricity under long term contract to Light, the distributor in Rio that is also controlled by EdF. Under pressure to resolve the logjam that was keeping thermal plants from closing in Brazil as the hydro shortage loomed, the government authorized four projects with different distribution companies—prices would be fully passed through, the plants could declare themselves "inflexible" at a level to cover take-or-pay clauses in gas contracts, and there was no limit on capacity. These projects have enjoyed stable operating histories, largely because of the relationship with their offtaker.

Norte Fluminense has been a positive investment for EdF, and is a small enough share of total generation that has not affected retail tariffs in Rio substantially. This outcome is in contrast to the case to Iberdrola's Termopernambuco, where the impact on retail tariffs has been large enough to invite consumer opposition; the 520 megawatt project comprises such a large proportion of generation costs for its offtaker (Celpe) that the plant has caused a 17% increase in the power tariff in the Brazilian state of Pernambuco. The price of power generated by Termopernambuco (R$57.51/MWh) is almost twice the price in energy auctions as of mid-2005 (R$37.83/MWh). In response to a wave of public interest litigation, a federal judge ordered Brazilian regulator ANEEL to reduce from 24.4% to 7.4% Celpe's requested tariff increase to cover the costs of purchasing power from Termopernambuco. The resolution of ongoing litigation around Termopernambuco may affect the other self-dealing projects, including Norte Fluminense.

We rate investment outcomes for Norte Fluminense to be **positive**. The project enjoys a secure offtaker and secure fuel supply, and thus far Light has not faced challenges from the regulator such as in Termopernambuco's case. We rate the development outcomes for Norte Fluminense to be **mixed**. With a stable gas supply, the plant is able to provide reliable energy and reduce Brazil's reliance on hydroelectricity. Nonetheless, the special arrangements (self-dealing, inflexible dispatch) necessary to support the project would not be replicable on a large scale without substantial risk and cost for the Brazilian electricity sector.

2.3. *Uruguaiana*. AES's Uruguaiana was the first private natural gas-fired project to be developed in Brazil, with a 1996 bidding conducted by CEEE, a then-public distribution company. CEEE has since split into two private companies (Rio Grand Energia, AES Sul) and one still-public arm (CEEE). Uruguaiana's original PPA with CEEE is now split ratably between the three successor firms. In contrast, to the other self-dealing projects, Uruguaiana, which sources gas from Argentina, sells to three very different offtakers. Gas supply has been a problem, particularly during the winter. Often

Uruguaiana has solved this problem by buying power on the spot market to cover its PPA obligations.

We rate investment outcomes for Uruguaiana to be **mixed**. The project has been plagued by the gas shortages that have affected all natural gas plants in Brazil. The project company has remedied this problem by purchasing electricity on the spot market from the plentiful hydro-reserves to meets its supply obligations, and has enjoyed stable relations with all three of its offtakers. We rate development outcomes to be **mixed** as well. While the project has generated little electricity overall, this is to be expected for a gas-fired plant in the Brazilian electricity market. Further, gas supply is not Petrobras' responsibility, as it is for the other gas plants. Uruguaiana's solution of buying electricity on the spot market to cover supply obligations likely imposes some higher costs on its offtaker, but these do not appear to be as costly as the revenue guarantees for the merchant plants or the must-run arrangements for the self-dealing projects. Further, in the case of Uruguaiana, the costs are shared among three offtakers.

2.4. *Caña Brava*. The universe of greenfield hydroelectric projects in Brazil that fall within the IPP study is small. Most new hydro projects were developed to sell to captive users or for self-supply. The Caña Brava project, developed by the Brazilian subsidiary of Belgium's Trachtebel ("Tractebel Energia"), is an exception. Caña Brava sells electricity under long-term contract to Gerasul, a generation company also partly owned by Tractebel Energia.

Under the market structure for electricity generation that prevailed from 1995–2003, the experience of developed hydroelectric power plants in Brazil is radically different than developing thermal projects. In the hydro system, financial settlement (paying contract prices) has been entirely divorced from physical settlement (dispatching electricity). In practice, this means that hydroelectric facilities market their electricity independently, but deliver their electricity collectively, in effect sharing hydrology risk with the entire system. Once a hydroelectric facility reaches commercial operations, project returns are stable and predictable.

We discovered no evidence that Caña Brava's experienced diverged meaningfully from this controlled model. For these reasons, we rate both investment outcomes and development outcomes to be **positive** for Caña Brava.

The strong performance may be under pressure. Under the new market structure for electricity generation, the commercial environment for hydroelectric plants will be radically different. Hydro facilities will sell electricity to a regulated power pool composed of all of the distribution companies in the country. This new model is not fully established yet, and substantial uncertainties remain concerning how auctions and financial settlement will be conducted. Nonetheless, existing generators have been unenthusiastic. Prices in the first auctions have been below long-run marginal cost. Perhaps more importantly, the management of offtake risk in the new power pool is unclear; generators are unsure about where payment responsibility lies (whether in the pool itself or some central authority, or directly with distribution companies), and have little means of pricing this risk.

3. CHINA.

China was an early entrant into the IPP market, starting with a joint venture between Hong Kong-based China Light & Power and the Guangdong provincial government to build a nuclear facility in the 1980s. This opened the door for the first true IPP—Hopewell Holding's Shajiao B project in Shenzhen. The bulk of the Chinese IPP market blossomed during the mid-1990s, with almost US$4 billion worth of IPP investment closing in 1997 alone. Just as precipitously, the market bottomed out, and in 2000 no project reached financial close.

In China, IPPs signed long term yuan-denominated offtake agreements with provincial electricity boards. In this decentralized environment, outcomes of the IPP program have been generally poor for investors. Investors have had a very difficult time facing numerous tariff reductions and other changes to the original contract terms. On the other hand, some might argue that the government got what it wanted—FDI to help ride out a tight monetary period in the early 1990s, and technology and management transfer from sophisticated multinationals. Increasingly, the Chinese markets have returned to liquidity and quasi-state spin-offs of the now defunct national power corporation have risen to assume a dominant role in the generation sector.

The project sample in China focuses on the large coal-fired projects that represent the vast majority of IPPs in the country. Within this group, project selection reflects two key variables. The first is ownership structure; in China many projects included entities affiliated with local governments—the study includes two such projects (Shajiao C, Shandong Zhonghua) and one wholly-foreign-owned project (Miezhouwan). The second is location; the economies of Fujian (Miezhouwan), Guangdong (Shajiao C) and Shandong (Shandong Zhonghua) have had different trajectories during the relevant period; examining projects across the three provinces allows us to isolate the impact of these market changes while controlling for a host of country-level factors.

3.1. *Shajiao C*. The 1980-megawatt coal-fired Shajiao C project was developed by Hong Kong based CEPA, and sold to Southern Company (Mirant) as part of the latter's acquisition of CEPA's IPP portfolio. The project was set up as a joint venture between local government entities that controlled 60% of the project, with a minority holding for foreigner investors. We rate <u>investment outcomes</u> for the project as **positive**, due to a unique security arrangement whereby the local partner (affiliated with the provincial government) would indemnify losses due to regulatory or tariff changes. As a result, both CEPA and later Mirant have exited Shajiao C for reasons unrelated to the project, reporting profits on the sale. This positive performance was also supported by the fact that Guandong province has enjoyed robust economic growth during the operations of Shajiao C, with steadily rising electricity demand. We rate <u>development outcomes</u> to be **mixed**. While the plant has helped meet rising demand, the indemnification clause essentially transfers cost from the consumer to the government, and suggests a continuing inability to enforce sustainable tariffs.

3.2. *Miezhouwan*. Intergen's Miezhouwan project was the first wholly-foreign owned IPP in China. The 724-megawatt coal-fired project was built in Fujian province, which has an electricity grid that is relatively isolated from the rest of the country due to transmission constraints. By the time Miezhouwan came online in 2001, previously optimistic forecasts of the electricity supply-demand balance had withered due in part to aggressive build-out of capacity and in part to a generous hydrological year in 2001. Miezhouwan was already more expensive than its competitors in the Fujian market, and with little demand to service, the project faced problems almost immediately when local authorities refused to certify commercial operations.

While the dispute continued for several years, the project's sponsors have since made several adjustments in the course of renegotiating the power sales agreement, including refinancing with domestic banks and changing fuel supply from Indonesian to Chinese coal suppliers. Nonetheless, the Miezhouwan model is not replicable for future investors, and we rate <u>investment outcomes</u> to be **negative**. On the other hand, <u>development outcomes</u> are **mixed**. As demand continues to grow in Fujian, the project may deliver much needed electricity at a lower renegotiated cost. However, the cost to Fujian and China in terms of deterring further investment is not yet clear—for now the country seems able to meet its needs internally, but this will not last forever.

3.3 *Shandong Zhonghua*. This 3000-megawatt project was developed jointly by Electricité de France, China Light & Power, and arms of the Shandong provincial government. The facility contains both brownfield and greenfield units, the latter financed in part by revenue from the operating units. Like Fujian, Shandong province operates an isolated electricity grid, meaning that supply-demand imbalances cannot spread across the country. Shandong experienced a period of oversupply in its electricity market in 2004, later than most of China. Like most Chinese IPPs facing a shifting energy supply balance, outcomes for Shandong Zhonghua followed suit.

We rate <u>investment outcomes</u> to be **mixed**. On the one hand, the project has endured the problem typical of China—an inability to secure agreed upon tariffs. In this case, problems appeared in the form of lower than expected tariff increases which failed to cover rising coal costs. CLP annual reports indicate that these problems have reduced returns on the project, but in early 2005 they were optimistic that disagreements with Shandong officials would be resolved soon. While Shandong Zhonghua is part of a country-wide strategy for CLP, the model is not replicable for most other companies, which lack the long-term interest in the Chinese market, or appetite for Chinese risk, characteristic of the Hong Kong-based utility.

We rate <u>development outcomes</u> to be **mixed**. Shandong Zhonghua has provided much needed electricity for the fast-growing economy in Shandong Province. However, technical problems kept the plant from meeting availability targets for the first three years of operations. The Chinese government has also succeeded in lowering the tariff substantially, securing a short-term benefit that may bring a long-term cost if China finds itself once again in need of FDI in power infrastructure in the future. Moreover, the local government has covered shortfalls in payments through a corporatized state company, which points to continuing inability to secure sustainable tariffs from end-users.

4. Egypt.

Egypt opened its generation sector to private participation in 1996, with a law that laid the foundations for a competitive bidding process for three IPPs that were awarded in 1998 and 1999. All three projects sell electricity under long term contract with Egypt's national utility holding company, EEHC, that are backed by a Central Bank guarantee. Fuel for the projects, all of which fire on natural gas, is provided by the Egyptian gas monopoly at a substantial discount from market rates. The Egyptian IPPs are occasionally cited as the most competitive in the world—for example, InterGen's (now Globeleq) Sidi Krir project bid a price of US$0.0254 per kWh. Turbulence in Egypt's IPP arrangements arrived with a 2002 economic downturn and subsequent devaluation of the Egyptian pound from 3.2 to 6 pounds against the US dollar. The Egyptian government has since stipulated that all new power generation projects must secure their own customers, i.e. the state utility will no longer be the guaranteed buyer of electricity and all foreign currency debt must be sourced from abroad. As of yet, there have been no bids submitted along the new provisions.

The project sample in Egypt contains all three operating IPPs. These projects are structured substantially similarly. Variation exists along only a few factors. First, Sidi Krir was sponsored by a major US power company (Intergen), while Suez and Port Said were sponsored by the French utility Electricité de France. Second, Sidi Krir obtained debt finance entirely from commercial banks, while the EdF found few commercial options available and ultimately turned to multilateral sources (the IFC) for substantial debt financing.

4.1. *Sidi Krir*. This 682.5 megawatt natural gas-fired power plant was the first IPP in Egypt. A competitive bidding process in 1996 generated substantial interest, with more than fifty firms applying for pre-qualification. The project was awarded in February 1998 to a consortium consisting of Intergen and Edison Mission Energy from the United States. The winning bid was US$0.0254/kWh, which was among the lowest electricity prices for an IPP in the developing world. The project fired on domestically produced natural gas that was supplied at a healthy discount by the Egyptian state gas monopoly. Project debt is wholly private—domestic Egyptian banks provided most of the financing on a project basis, albeit denominated in dollars. International commercial banks provided the rest of the debt, with no involvement from multilateral or bilateral lenders. Intergen and Edison Mission sold their interests in Sidi Krir in 2005, apparently as part of global restructuring of their power business, and not as a reflection of troubles in the project itself. The plant is presently owned by Globeleq, which was spun off the UK's Commonwealth Development Corporation (CDC) in 2002.

4.2. *Suez & Port Said*. These projects, Egypt's second and third IPPs, are each 683-megawatt natural gas-fired power plants awarded to Electricite de France. The projects were awarded and developed along substantially similar lines as Sidi Krir. The significant difference was that EdF sourced its lending from the IFC and a syndicate of international banks and institutional investors. This difference reportedly reflects the fact that by the time the projects sought financing, Egyptian officials lacked the appetite to mobilize additional domestic lending for power plants. With European commercial banks reluctant to invest in what they deemed insufficiently environmental projects (i.e. plants were for gas-fired steam generators and not combined cycle), EdF turned to a multilateral, namely IFC to help secure additional debt. EdF, citing its plans to concentrate its assets in Europe, sold its equity in the plants in 2006; both Port Said and Suez are presently owned by Kusas Nusajaya, a subsidiary of the Malaysian firm Tanjong Public Limited Company.

We rate the <u>investment outcomes</u> for all three projects as **positive**. No major disruptions in construction, operations or payment have been reported. The power sales contracts have weathered a macroeconomic shock intact, and continue to generate revenue. The only negative outcome identified was that sponsors for each project had invested at least partly on the assumption that Egypt would continue to open investment opportunities. Egypt did have plans to solicit additional projects (up to a total of fifteen IPPs), but reversed course after the cost of the projects spiraled with the devaluation.

We rate the <u>development outcomes</u> for Egypt as **positive**. The cost of the payments to the IPPs have almost doubled with the 2002-3 devaluation of the Egyptian pound, and Egyptian officials now express some dissatisfaction with the projects as being too expensive. Nonetheless, because (i) the original bids were very competitive, (ii) the IPP sector remains small, and payments manageable even if unexpectedly high, and (iii) electricity is being generated, the experience seems a positive one for Egypt. Additionally, although the government has turned to state and multilateral sources of capital for new development, the early IPP investments have been conducted in a manner that provided valuable experience to the country, and have not unduly prejudiced the prospects for future investment.

5. India.

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

The project sample in India consists of four projects—two each in Andhra Pradesh and Gujarat. States were selected for (i) having more than one IPP, (ii) exhibiting variation in the ownership structures in the IPP sector, and (iii) exhibiting variation in the reform of the electricity sector. Andhra Pradesh was an early and relatively successful reformer in the electricity sector, and has IPPs that span all three regulatory regimes for IPPs (fast track, cost bidding, tariff bidding). All of the IPPs in Andhra Pradesh are foreign-local partnerships and fire on a combination of naphtha and natural gas from state owned gas companies. The principal variation is between the regulatory regime: the project examines both GVK Jegurupadu, an early "fast-track" project, and Lanco Kondapalli, a later project that was competitively bid on the basis of tariff.

Gujarat is a heavily industrial state and was a late reformer in the electricity sector. IPPs in Gujarat were bid out on the basis of cost. They burn natural gas that is sourced from local private companies, and exhibit variation in their power sales arrangements. The project examines China Light & Power's Paguthan IPP (a currently wholly-foreign owned project that sells electricity solely to the state electricity board), and Essar Power (a locally developed project that devotes a portion of its power sales to self-consumption).

In addition, we have drawn on the extensive literature surrounding the Dabhol project in Maharashtra, and have drawn on public sources (including local media and SEC failings) in tracking from afar an ongoing dispute in Tamil Nadu—including recent reports of improving relations and a potential settlement between the IPPs and the host government. Although detailed case studies were not possible in these cases, we include particular examples in our overall analysis where possible.

5.1. *GVK Jegurupadu*. The 216-megawatt Jegurupadu project, sponsored by GVK Industries and CMS Energy, was a "fast-track" project in India, developed under the 1991 amendments to India's electricity law. The project was awarded via negotiation and developed by GVK and CMS with support from a central government counter-guarantee, escrow facilities for payment from its state offtaker, and loans and equity investment from the IFC and ADB.

Prior to commercial operations, GVK's PPA was renegotiated on several occasions. Renegotiation is often seen as one sign of trouble for an IPP; however, according to AP Transco officials these renegotiations largely favored GVK. Specific elements of the renegotiations they point to include: (i) the eventual provision of a GoI counter-guarantee; (ii) a change in the fuel choice clause that allowed naphtha as an alternate fuel; (iii) establishing an escrow mechanism and requiring that it to open prior to

COD to cover construction period; and (iv) a richer plant load factor ("PLF") incentive formula, which remains at a low 68.5% PLF and was changed from a percentage of the return on equity to a percentage of overall equity committed to the project. The key terms that changed in the government's and/or lenders' favor were: (i) a revised ceiling on capital cost; and (ii) a clause providing for debt conversion to equity in the event of default. In addition, the GVK term was reduced to 18 years, to reflect the fact that the normal useful life of a gas-fired plant is less than 30 years.

Jegurupadu has been paid under the terms of the PPA, although with some ongoing disputes. With a tariff set on a cost-plus basis, the project came in above projected cost and AP Transco has continued to pay according to projected cost while the CEA, which is supposed to approve project costs, has dragged its feet. Additionally, returns have been eroded by difficulties keeping operating costs within the 2% pass-through provided in the PPA. Nonetheless, we rate the investment outcomes as **positive**—these disputes appear to concern marginal amounts of money. The tariff formula is calculated to provide a 16% rate-of-return at 68.5% PLF with incentives for higher load factors. Even with ongoing disputes, the plant has often run at or above 85% and should be performing well financially. Although the foreign investor, CMS, has now exited the project, the primary local shareholder, GVK, is continuing with plans for expansion and additional power sector investment.

We rate the development outcomes as **mixed**. On the positive side, GVK pioneered private power development in Andhra Pradesh, likely opening the door for subsequent development. The project has a strong environmental record, and as with other IPPs, has removed the costs of project development from government responsibility.

Nevertheless, state officials express dissatisfaction with GVK on several counts. These objections revolve largely around the costliness of the plant—records kept by the Ministry of Power indicate a fixed cost of Rs. 3.778 crore/MW, which is near the high end of the spectrum for gas-fired IPPs in India. The project sponsors counter that several factors contributing to cost in GVK are beyond their control—such as high costs for EPC services in the global market at the time of project development, and high interest rates. There have been at least some discussions on refinancing the project and passing through cost savings to consumers (as some other Indian IPPs have done), but both sides argue that the other is holding up an agreement on this count.

5.2. *Lanco Kondapalli*. The 330-megawatt naphtha and natural gas-fired Kondapalli plant is a subsequent Andhra Pradesh project, developed via competitive bidding on the basis of final tariff. Kondapalli is the only one of six tariff-bid projects in Andhra Pradesh to reach commercial operations. Shortly after the projects were awarded, naphtha prices were deregulated and rose dramatically. After securing financing prior to a contractual deadline for these plants, as well as covering the cost of converting to natural gas, Kondapalli came online in 2000.

We rate the investment outcome for Kondapalli as **positive**, even through difficulties. The plant has been involved in a series of disputes with state offtaker AP Transco regarding sharing the benefits of below-cost construction and regarding state testing to confirm the rated capacity of the plant. Nonetheless, sponsors report a positive investment in the project, and no other public information suggests further problems.

We rate development outcomes for Kondapalli as **positive**. As a symbol of the benefits of continuing experience with private power, and of relying on competitive bidding, project outcomes from Kondapalli for Andhra Pradesh seem to be relatively positive. Nevertheless, government officials have stated dissatisfaction with Kondapalli in two primary areas. First, Kondapalli's final cost was lower than the cost included in the initial bid by Lanco. Kondapalli reduced its tariff downward to account, in part, for this new development. Nonetheless, APTransco filed a notice stating that it would only pay based on the tariff resulting from CEA's approval. Lanco resisted this position, arguing that Kondapalli is a tariff bid project, and the tariff in the PPA should govern. Lanco successfully sought a stay in court against APTransco's notice and APTransco is currently paying the original tariff rate while the matter is litigated.

Second, the parties to the contract are also involved in a dispute regarding the rating of capacity. The PPA contemplates installed capacity of 368 MW. According to AP Transco, the PPA formula indicates an actual installed capacity of 351 MW, but AP Transco pays based on the contract capacity of 368 MW. This dispute was referred to the regulator, until Lanco obtained a stay, and is now in court.

In sum, while Andhra Pradesh is often viewed as a relatively investor-friendly state for IPPs, the government and IPPs have had their share of smaller disputes, which reflect state official's ambivalent position toward the much needed private power producers that are nevertheless viewed as expensive and inflexible.

5.3. *CLP Paguthan*. Paguthan was developed in Gujarat by local Indian developer Torrent Group, along with Powergen of England. Subsequently, China Light & Power acquired Powergen's portfolio of projects in Asia, including Paguthan. The 655-megawatt natural gas-fired plant has been one of the first plants in India (along with Essar Power, also in Gujarat) to secure gas supply from a private firm, with concrete delivery requirements. The relationship with state offtaker Gujarat Electricity Board has been rocky—the tariff for Paguthan has been renegotiated on several occasions, forcing sponsors to make adjustments wherever possible to earn a return.

We rate the investment outcomes as **mixed**. While the project appears to have produced a return on investment, the rate has been eroded by numerous ongoing disputes. The fact that the project has been able to ameliorate the full force of these troubles by tapping the private gas market speaks to the fortuitous location and effective management of the plant.

We rate the development outcomes as **mixed** as well. On the negative side, the offtaker has had marked troubles affording the PPA. These troubles reflect in part continued problems in reforming the state utility itself to generate sufficient cash-flow.

The Ministry of Power reports that Paguthan came in with a fixed cost of Rs. 3.509 crore/MW, which places the project in the low-middle range of fixed costs for IPPs in India, and in the low range for gas-fired projects. Data maintained by the Central Electricity Authority indicates recent dispatch of between 70-85% of capacity, a relatively healthy number.

Beyond pure cost considerations, the Paguthan project offers several other attractive features. The private fuel contracts have pioneered the development of private fual markets in India, and the project has invested substantial amounts in environmental protection, for example by utilizing dry-cooling towers, and was accredited with ISO 14001 certification in 1999.

5.4. *Essar Power*. The 515-megawatt naphtha and natural gas-fired Essar Power plant was developed by Essar, a domestic Gujarati firm that originally aimed to provide electricity only for its steel plant. At the request of the Gujarat Electricity Board, the original plant was expanded from 215 to 515 megawatts. The project struggled to source natural gas in the uncertain Indian gas markets, often running partly on expensive naphtha. Essar has remained stable through troubles in the naphtha market, the transition to gas, and others, in part by always having a dedicated offtaker for at least some of its load. In particular, when gas was scarce and Essar ran primarily on naphtha, steel prices were high and the project could operate profitably by powering the steel plant; when steel prices fell, the decline coincided with Essar Power's new private gas contract to source gas from the Petronet LNG terminal.

We rate investment outcomes for Essar Power as **positive**. The PPA was renegotiated once, in August 2003, reducing a number of pass-through variable costs, including interest rate reductions through refinancing and fuel cost reductions through the switch to gas. Essar has since refinanced and paid off its dollar-denominated loans. The project has been resilient to an uncertain operating environment—its hybrid power sales arrangements meant that when naphtha prices were high and GEB offtake low, the steel demand remained strong, which allowed the project to maintain a 60% to 70% PLF. After the 2002 downturn in the steel industry, the GEB began taking more power, which has increased greatly since 2004.

We rate development outcomes as **positive** as well. The plant is among the cheapest, in terms of fixed cost per MW of capacity, of the gas-fired IPPs in India. Further, Essar is able to serve a smoothing function in the state electricity system, by meeting unexpected demand spikes because it is always ramped up for its steel production. Although not reflected in interviews, we also consider it likely that the state has benefited from the flexibility that Essar has maintained by relying in part on its steel production for power sales.

5.5. *The Tamil Nadu IPPs*. Tamil Nadu has been a stark counterexample to the relative successes of Gujarat and Andhra Pradesh. Five projects have been developed here to sell electricity to the Tamil Nadu Electricity Board. These five projects exhibit a diverse mix of fuel choices, technology, local and foreign investors and strategies. In

2001, when all five of the projects had come online, the Tamil Nadu Electricity Board ("TNEB") announced that it would pay only 2.25 rupees/kWh to each plant, which was below contracted tariffs for each of the projects. During the dispute, the TNEB has continued to track its arrears to the projects (based on the difference between contract payments and actual payments)—which at one point reached at least $150 million.

In general terms, project outcomes in Tamil Nadu have been **negative** for both investors and for hosts. Despite efforts to resolve the issue on both sides, investors have likely paid a heavy price for four years of underpayment. For the government, even reduced payments have been difficult, and the prospect of repaying the outstanding arrears will have a substantial impact on the state's balance sheet. The core problem for TNEB is its inability to collect revenue sufficient to cover generation costs. Nonetheless, contracting for IPP power that exceeds its ability to pay has prejudiced the state's ability to continue attracting sustainable investment in the future. Additionally, the plants often appear to be relatively expensive—either firing on naphtha (PPN Power) or with relatively high fixed costs (ST-CMS) among Indian IPPs.

6. KENYA.[2]

Kenya stands out in our country sample together with Tanzania for having developed IPPs within an electricity sector comprising only about 1 Gigawatt (GW) of generating capacity and in which only a small percentage of the population has access to electricity (approximately 15%). For much of the 1990s, the country faced an embargo from the international aid and financial community reflecting a poor record on corruption and democratic governance. In this environment, private finance was relied upon as the only alternative for the electricity sector. IPPs arrived in Kenya in two phases, beginning in 1996 with the passage of a law authorizing private participation in the generation sector. The first tender, which actually began in 1995, produced two BOO projects (OrPower4 and Tsavo Power) along a classic IPP model—20 year PPAs for energy sales to a single state utility, with minimum offtake provisions and elaborate security mechanisms, but conspicuously with no sovereign guarantee (Tsavo Power became the first IPP to be financed on a project basis in East Africa without a guarantee as credit support for the offtaker; OrPower4 has not completed financial closure yet).

Due to the fact that these projects were slow in progressing from the original tender in 1995 to commercial operations for Tsavo in 2001, Kenya contracted two "stop-gap" IPPs for a total of 90 megawatts: Westmont and Iberafrica. These projects had only seven year contracts and, because of a requirement to come online within 11 months of signing the PPA, were financed by the developers on balance-sheet. The project sample in Kenya comprises two cases, one from each regulatory framework.

6.1. *Tsavo*. Sponsored by Cinergy-IPS, Wartsila, and the International Finance Corporation, this 75 megawatt diesel project was originally tendered in 1995, yet reached commercial operations only in 2001 due to delays in obtaining financing. These difficulties reflected, in part, the riskiness of investment in Kenya, which for much of the

[2] The author is indebted to Katharine Gratwick for this discussion of the Kenyan experience.

1990s faced an aid embargo because of poor record on corruption and democracy, and the fact that the government did not extend sovereign guarantees for its IPPs.

We rate the investment outcomes for Tsavo as **positive**. One illustration of the positive investment outcome is that although the IPP has faced pressure from government officials to lower its tariff, Tsavo has been able to resist these efforts thereby safeguarding the expected ROE. The positive investment outcome reflects four factors. First, the plant was awarded through an auction conducted according to international competitive bidding guidelines (although only three firms submitted bids). Second, Tsavo's tariff is competitive with those of the incumbent state-utility KenGen. Third, the project has benefited from its selection of partners; the IFC has played a part in deterring government pressure, and IPS is an arm of the regional Agha Khan Foundation that has operated in Kenya for decades. Finally, Tsavo established a well-known community development fund in Kenya.

We rate the development outcomes for Tsavo as **mixed**. The country received quality power (with availability averaging 92%), but ultimately later than initially expected. Furthermore, although tariffs are deemed comparable with those of similar KenGen plants, some stakeholders argue that the security package required by Tsavo has diverted funds from KPLC, which could have been put to better use.

6.2. *IberAfrica*. IberAfrica is a 44-megawatt diesel-fired project developed by Union Fenosa of Spain with additional investment (loans and equity) from the KPLC Pension Fund (KPLC is the state-owned holding company for the electricity sector). As a "stop-gap" IPP brought on to forestall an electricity shortage, IberAfrica was financed on balance sheet by its sponsors, and reached commercial operations within a year of being awarded. Like the other stop-gap project (Westmont), IberAfrica is relatively expensive in terms of fixed costs, a fact that reflects the short contract duration (7 years), the balance sheet financing, and the lack of a sovereign guarantee. While Westmont cost $20 million for 46 megawatts of capacity, IberAfrica cost $65 million for 56 megawatts of capacity (largely reflecting technology and site differences). However, unlike Westmont (a barge-mounted diesel peaking facility), which saw its per/kWh tariff soar when hydrological conditions returned to normal and thermal units were scaled back, IberAfrica (a land-based diesel baseload facility) reduced its capacity payment in order to remain at a more reasonable level relative to the rest of the sector. IberAfrica has since secured a new 15-year PPA, with a capacity fee 50% lower than that for the first contract.

We rate the investment outcomes as **positive** for the following reasons. First, Iberafrica was able to secure a second 15-year PPA. Secondly, over the long-term, i.e. 22-year basis of its two PPAs, the firm expects to earn an average return of approximately 15%. Finally, Iberafrica has enjoyed robust demand from KPLC, which has consistently sourced power from the project.

We rate the development outcomes for the country as **mixed**. Although Iberafrica's first PPA was considered to be costly to the country, the firm voluntarily reduced its charge in 2002 to show its commitment to Kenya and the electricity sector. Its second

PPA, negotiated with the oversight of the regulatory board, yielded a further reduction. Its availability has been good, although slightly less than Tsavo (at 89%). Iberafrica has also made a (small) contribution to job creation as the majority of its employees Kenyan nationals. Finally, the company has recently embarked on studies to change the fuel specification that would further reduce the cost of generation to the consumers without compromising on the environmental impact.

7. MALAYSIA.

Malaysia entered the IPP market in 1993, following mounting troubles in its electric power utility in the early 1990s. The 13 Malaysian IPPs, which were predominantly large natural gas-fired projects, sold their output under long term ringgit-denominated contracts to Tenaga Nasional Berhad, the national utility. Most of the projects were arranged in a round of investment during 1993-94, and were not competitively bid, but rather allocated in a selective tender or negotiated directly, resulting in higher tariffs than Thailand's competitive projects, and handsome profits for the sponsors. Unlike most other countries, which involved substantial participation from US and European utilities, the project developers in Malaysia were almost exclusively Malaysian firms, while capital was sourced almost entirely from domestic markets, including state pension funds and other institutional investors. The Malaysian IPPs faced some pressure during the Asian financial crisis, but available information suggests that the contracts were not renegotiated and profits remained healthy. Many of the original IPP sponsors in Malaysia have been among the most profitable companies in the country, and continue to develop projects there.

No in-depth project studies were undertaken in Malaysia.

8. MEXICO.

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

IPPs in Mexico are all natural gas-fired, combined-cycle, BOO projects sponsored by foreign firms, though occasionally in partnership with local companies. Project selection in Mexico reflects only two key variables: the investor composition (foreign/local), and the evolving regulatory regime. Three distinct models for IPPs are observed in Mexico, with differences revolving around the fuel supply and exit/termination provisions. The project sample in Mexico includes three projects: one project from each regulatory regime, and one project that includes a local partner.

8.1. *Mérida III*. Mérida III, the first IPP and first BOO contract in Mexico after the 1992 law, is a 484-megawatt combined-cycle, gas-fired power generation facility, awarded to AES Mérida III, among a pool of 19 bidders. The lead sponsor is AES Corp., along with Nichimen Corp. (Japan), and Mexico's Grupo Hermes, a Monterrey-based industrial group. CFE awarded the PPA in February 1997. The project was built by Westinghouse under a turnkey contract and started operations in June 2000. The 25-year PPA with CFE provided for the sale of electricity at a price of less than 3 cents/kwh, below the subsidized SOE power tariff of 4-6 cents/kWh at the time of the bidding. Natural gas is supplied by CFE, which purchases the gas from the privately-owned and operated Mayakán Pipeline.

Despite some problems during construction due to turbine shortages in 1995, we rate both <u>investment outcomes</u> and <u>development outcomes</u> as **positive** for Merida. The fundamental contracts have been stable and performed without any apparent dispute since the project was awarded. Prices are low, and the introduction of natural gas with IPPs in Mexico has facilitated a move away from old, dirty and inefficient oil-fired plants. Part of this favorable evaluation reflects the lack of any significant disruption in Mexico during the late 1990s. Due to this macro stability, potential problems in the Mexican IPP sector, including the costly Pidiregas program, inconsistent fuel contracts that place later plants at some disadvantage, and ongoing delay in larger power sector reform (including a non-transparent dispatch and highly subsidized tariffs), have not affected the existing IPP projects significantly.

8.2. *Río Bravo II*. Río Bravo II is a 495-megawatt natural gas-fired, combined-cycle power plant developed and 100% owned by Electricite de France, next to two other EDF projects (Río Bravo III and IV). Rio Bravo II sells its output to CFE under a 27-year PPA based on an annual plant load factor of 80%, with fuel also provided by CFE. The project cost of $234 million, with substantial IFC financing that amounted to $165 million in various tranches.

As with Merida III, we rate both <u>investment outcomes</u> and <u>development outcomes</u> as **positive**. The fundamental contracts have been stable and performed without any apparent dispute since the project was awarded. Prices are low, and the introduction of natural gas with IPPs in Mexico has facilitated a move away from incumbent oil-fired plants. With no major disruption in Mexico, however, potential problems in the Mexican IPP sector (*see discussion above*) have persisted. Although these problems may pose a problem for future development, or in some scenarios for existing plants, they have not adversely affected the outcomes for Mexico's IPP's to date.

8.3. *Monterrey III*. Monterrey III is a 1,140-megawatt combined-cycle power plant entirely owned by Iberdrola of Spain, operated by Alstom, and with financial support from the IADB. Monterrey III was developed in two phases, with additional capacity being installed under different schemes authorized by the IPP law. Initially, Iberdrola requested authorization to install 570 megawatts of capacity, to sell to CFE under a 25-year PPA. Because the bidding documents and the PPA allow additional capacity for self-supply or contract with third parties, Iberdrola developed an additional 620 megawatts for sale to local industry in Monterrey via bilateral sales contracts.

Monterrey III epitomizes the **positive** outcomes—both investment and development—for IPPs in Mexico. The plant contributes more than 1,000 megawatts of private generation to the Mexican grid, which is particularly critical in Monterrey, one of the most industrialized cities in the country. The project also utilizes efficient and environmentally-friendly technology, and is selling electricity at extremely low tariffs. At the same time, Monterrey seems to be performing well for investors; Iberdrola's sales in Mexico increased by 64% thanks to the Monterrey project, and the company plans an investment in Mexican power generation of US$3 billion from 2001-2006.

9. THE PHILIPPINES.

The Philippines entered the IPP market early, with a 1988 presidential decree authorizing private investment in generation. Major investment in IPPs occurred in response to a major electricity crisis during 1991-93. In broad strokes, the 40+ IPPs that were developed in the Philippines proceeded in three stages: first, a series of "crisis" plants with shorter (5-12 year) contracts, which usually fired on oil or diesel; second, a group of large 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 was the Asian financial crisis, which caused the local currency cost of the dollar-denominated PPAs to soar, along with the cost of fuel. Public dissatisfaction focused heavily on the IPPs, whose contracts stood out in sharp relief against the soft budgets of state-owned, amortized power plants. In 2001, a government committee was appointed to review the IPP contracts. A widely publicized renegotiation effort followed, however, contracts were substantially honored in this process and investors remain largely pleased with their experience in the country.

The Philippines IPPs are perhaps the most diverse among the countries in the IPP study, exhibiting variation in fuel sources, investor composition, contract type and duration, extension of sovereign credit support, and method of solicitation. Project selection in the Philippines reflects three variables: fuel choice, regulatory regime, and choice of offtaker. The project sample consists of two of the early "emergency" plants (Navotas I and Cavite) and three prototypical long-term IPPs (Pagbilao, Quezon and Casecnan).

9.1. *Navotas I*. Developed by Hong Kong-based CEPA, Navotas I was the first IPP in the Philippines, with a 10-year energy conversion agreement with Napocor backed a full performance undertaking. 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. Designed as a peaking facility, this diesel-fired plant often ran as baseload during the crisis, before being throttled back by the mid-1990s.

We rate the <u>investment outcomes</u> for Navotas I as **positive**. Although firing on expensive diesel oil, and utilized at very low levels for most of the decade, Navotas was paid under the original contract. At the expiration of the original PPA, Mirant negotiated to buy the BOT project from the government. We rate the <u>development outcomes</u> as **positive** also. As the first IPP in the country, Navotas I pioneered private power investment, and led to one of the largest IPP programs in the world. The plant also helped alleviate the power crisis, and the relatively short contract minimized the high cost of paying for the rarely dispatched plant when the power system stabilized.

9.2. *Pagbilao*. In 1991, CEPA began three years of negotiations that culminated in the 1994 signing of another ECA for the 700-megawatt Pagbilao coal-fired plant. Like Navotas I, Pagbilao was awarded through a bidding process (albeit with only two bids), and also became a blueprint for future IPPs in the Philippines. 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. Pagbilao, along with CEPA's entire South East Asian IPP portfolio (outside of Indonesia), was sold to Mirant in the late 1990s.

We rate the <u>investment outcomes</u> for Pagbilao as **positive**. 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. Given Mirant's leveraging of the overnomination clause in the contracts for each of its plants, additional sales via a marketing agreement with Napocor, and the remarkable profitability reported in the Philippine business press, it is likely that actual returns have been higher than 17.5%.

We rate the <u>development outcomes</u> as **positive**. Pagbilao provided the blueprint for future IPP development in the Philippines, and helped diversify the fuel base away from expensive diesel towards cheaper coal. There are some qualifications, notably criticism in the government IPP review that Pagbilao had heavily frontloaded its cashflow, and records of low dispatch levels (around 40% in the late 1990s). The frontloaded cashflow profile may have contributed to Mirant's flexibility during the renegotiations, however, and the low dispatch levels likely reflect Napocor's problems delivering fuel and persistent problems in disciplining dispatch by the regulator.

9.3. *Quezon*. The Quezon plant is a 460-megawatt coal-fired facility, developed by PRM Power, a local consulting group, along with Intergen and Ogden (now Covanta) from the United States. The project is connected to the national grid via a 31-kilometer transmission line built and owned by the project sponsors. The plant uses standard coal-fired steam generator technology and has been outfitted with extensive emissions abatement equipment. Although relatively expensive in terms of cost/MW of installed capacity, Quezon helped expand the share of coal in the Philippine electricity sector, and pioneered a range of firsts for project finance in the country—the project was the first IPP in the Philippines to be financed without any sovereign guarantee and solely on the credit of its offtaker (Meralco), and was also the first to access international capital markets, with a $215 million bond offering in the US after financial close.

We rate the investment outcome for Quezon as **positive**. The project endured some stress due to poor technical performance in the early years of operations, disputes with its offtaker Meralco, and has seen several provisions of project contracts renegotiated. Nonetheless, the project has serviced its debt, and has maintained a healthy credit rating for its bonds. Project sponsors and managers have expressed satisfaction with the project's performance. Equity turnover seems motivated by company-wide strategic decisions. Quezon's original sponsors (PRM Power, now GN Power) are developing another project in the Philippines.

We rate development outcomes for Quezon as **positive** as well. 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. As such, the success, or at least stability, of the Quezon project will illustrate the viability of IPP financing without sovereign guarantees. 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.

9.4. *Casecnan*. This BOT plant, a rare unsolicited project among IPPs in the Philippines, was developed by CalEnergy in cooperation with Peter Kiewit Sons, Ltd., which together held 70% of project equity, and two local partners. Project development began in 1994 with a PPA signed between the National Irrigation Administratoin and CalEnergy, followed by financial close in 1995, but the project did not come online until 2001, due in part to a dispute with the original EPC contractor, Hanbo, a South Korean firm that declared bankruptcy in the midst of construction.

Casecnan consists of a power plant producing 140 megawatts of electricity as well as a system that delivers irrigation water from the dam. NIA is the offtaker for both irrigation water and electricity (which is onsold to Napocor). NIA's obligations under the PPA are backed by a full performance undertaking from the Philippine Central Bank. Power sales arrangements require NIA to purchase 100% of the power actually generated by the plant, on a take-or-pay basis.

Casecnan was heavily criticized in the government review, largely because of high levellized costs and an ongoing dispute over guaranteed water flow in the river feeding the plant's turbines. For its part, 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. Casecnan filed a notice of arbitration before the ICC in August 2002, although the disputes were eventually settled without arbitration.

We rate investment outcomes as **mixed**. The project appears to be profitable, but the turbulent relationship with government counterparties and local civil society has whittled away at these returns. We rate development outcomes as **negative**. The project grew out of an unsolicited proposal and has attracted suspicion of corruption in its award and negotiation. The project took almost seven years to come online, after construction delays and disputes, and came at a markedly high cost per megawatt of installed capacity.

9.5. *Cavite*.[3] In the late 1990s, Covanta Energy acquired a controlling interest in the 63-megawatt Cavite EPZA (also commonly referred to as the "Magellan Cogeneration" project) plant. This diesel-fired plant sold its output primarily to local export processing zones ("EPZ"), with excess energy sales to NPC. The terms of sales to the EPZ's and Napocor differed in notable ways. Most importantly, the tariff for sales to Napocor were set according to standard practice—with capacity and energy fees and some indexation to the US dollar. On the other hand, sales to the EPZ's were undertaken at a discount to Napocor's prevailing grid rate. As a result, reductions to Napocor's tariffs, most recently in 2002, negatively impacted Covanta's revenues. This also means that other risks normally passed through to the offtaker, such as fuel price, are largely left with the project.

In 2002, the Philippine Economic Zone Authority, which is the primary offtaker for the project, served notice of termination of the PPA with Cavite. Subsequently, local courts granted a permanent injunction staying termination, pending resolution of the Authority's claims against Covanta, which include "non-reliable service" and "improper substitution of National Power Corporation Power for Cavite's production." In 2002, Covanta wrote off its investment in Cavite.

We rate both investment outcomes and development outcomes for Cavite as **negative**. The project was structured in haste and has suffered at times from poor fuel availability, disputes with offtakers, and suspicions of corruption. As noted, in response to the severe problems facing the plant, Covanta wrote off the remaining investment in 2002.

10. POLAND.

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

[3] *Primary Sources:* INTER-AGENCY COMMITTEE ON THE REVIEW OF THE 35 NPC-INDEPENDENT POWER PRODUCERS (IPP) CONTRACTS, FINAL REPORT (5 JULY, 2002); Covanta Energy, Form 10-K (2003)

coal-fired project by PSEG—sell their energy under long term contract to the Polish grid operator and local distribution companies.

Continuing efforts to reform the sector, and Poland's efforts to join the European Union, have caused problems for the IPPs. The Polish legislature has made several attempts to cancel PPAs and provide compensation in an effort to transition to more competitive generation markets. The IPP contracts, signed between PSE and several generators, while necessary to receive financing, lock in higher prices than would be likely in a competitive market, and prevent Poland from moving towards a competitive market as required under EU law. Poland's plan was to cancel the contracts and compensate the generators; such compensation is consistent with Polish law which requires compensation for takings. However, the EU competition authority has intervened, arguing that the PPAs, while necessary to finance investments in the mid to late 1990s, conferred a "non-commerical advantage" to IPPs in violation of EU state aid law, and thus prohibiting compensation. This dispute remains unresolved.

The project sample includes the two projects in Poland that qualify as private greenfield power plants. The projects vary along two important dimensions. The first factor is fuel. Poland is overwhelmingly dependent on coal for electric power generation, but has a stated goal to incorporate gas into the power sector. The projects include one coal-fired (Elcho) and one gas-fired plant (ENS). The second factor is timing. ENS reached financial close in 1997 and began operations in 1999 while Elcho did not begin operating until 2004—just weeks before the government announced its intention to cancel the long-terms PPAs.

10.1. *Elektrocieplownia Nowa Sarzyna*. ENS is a natural gas, combined-cycle, combined heat and power plant with an installed capacity of 116 megawatts (electricity) and 70 megawatts (heat), developed by a Polish energy sector entrepreneur who partnered with Enron to finance, construct and operate the plant. ENS signed a 20-year PPA with the Polish power grid company (PSE), in April 1997, and has a 20-year natural gas contract with the Polish National Oil & Gas Corporation. The project was highly leveraged—total project cost was $132 million, but project sponsors secured $118.5 million of debt from ten European banks.

We rate investment outcomes for ENS as **positive**. Commercial operations began in 2000, several years before the debate regarding liberalization and the cancellation of PPAs began. As of 2005, the contracts had not been cancelled, providing at least an initial period of stability and firm contract payments. The efforts of the Polish government to fashion a compensation scheme for the contracts in the event of cancellation suggests that the eventual costs may be minimized.

We rate the development outcome as **mixed**. PSE was constructed at considerable cost per MW of capacity for a natural gas plant ($1138/MW), and the 20-year PPA has run counter to the liberalization effort of the Polish government since 2003. While the project has helped to diversify the fuel base away from coal, electricity sold by ENS under the PPA has reportedly been more expensive and probably unnecessary (given the oversupply that existed at the time), than the already existing coal fired capacity.

10.2. *Elcho*. Elcho is a $324 million coal-fired, combined heat and power plant with an installed capacity of 220 megawatts (electricity) and 500 megawatts (heat), owned by PSEG (88.8%) and EC Chorzow, a Polish power generator. Elcho sells electricity pursuant to a 20-year PPA that calls for PSE to purchase 100% of Elcho's electricity output and a similar contract with the local district heating company for the purchase of 100% of Elcho's steam output. The project achieved financial close in November of 2000, and began commercial operations in January 2004. Dresdner Kleinwort Bensen was the sole lead arranger and underwriter for the project financing ($270 million), 28% of which was denominated in Polish Zloty.

We rate investment outcomes for Elcho as **negative**. Elcho began commercial operations the same week as Polish authorities announced they were canceling the PPAs, and has been mired in disputes over compensation ever since. Public reports indicate that PSEG has demanded between $370 and $420 million in compensation, and has threatened to suspend future investment in Poland.

We rate development outcomes as **negative**. Elcho has imposed the same costs on Poland as ENS, but lacks the central benefit of fuel diversity.

11. TANZANIA.[4]

Embarking on power sector reform in the early 1990s, Tanzania made IPPs a pillar of its reform strategy. Songas and IPTL, the country's two IPPs, have delivered tangible benefits, but not without controversy. Both projects have delivered critical power in recent years, helping to avoid load shedding. One of the projects was taken to international arbitration over a dispute related to construction costs. The state electric utility, Tanzania Electric Supply Company Limited (TANESCO), currently pays more than 50% of its current revenue towards combined fuel and capacity charges for the IPPs. The Government of Tanzania (GoT) is intervening to assist TANESCO with its monthly IPP payments. With twenty-year Power Purchase Agreements (PPAs) between IPPs and TANESCO, these costs are expected to continue, albeit with some modifications due to refinancing, fuel conversion and further development of the natural gas market.

The project sample includes the two projects in Tanzania that qualify as private greenfield power plants. The projects vary along two important dimensions: multilateral involvement and fuel type.

11.1. *IPTL*. Independent Power Tanzania Limited (IPTL) was the first IPP to begin to sell electricity to the national electric utility. The project was independently negotiated and developed by Malaysian investors, a local Tanzanian firm and the GoT. Construction was complete in 1998, but IPTL started producing power only in January 2002, after a three-year delay resulting from a dispute over construction costs and related

[4] The author is indebted to Katharine Gratwick for this discussion of the Tanzanian experience.

capacity payments. The 100-megawatt diesel plant consists of ten medium-speed units of ten megawatts each, which presently run on imported heavy fuel oil. The project was originally intended to convert to domestic natural gas, but the shift is still pending.

We rate investment outcomes as **mixed/negative**. The arbitration process shaved US$30 million off of the plant cost claimed by IPTL. During arbitration, Mechmar, the main shareholder in IPTL, incurred significant debt and has since been seeking to sell its share. VIP, the local partner has indicated its dissatisfaction with its investment and has seen no profits to date. VIP took IPTL to court shortly after the plant commenced commercial operations, alleging business fraud and failure by Mechmar to contribute equity. VIP has also since objected to an attempt by IPTL to devalue VIP's shares. The dispute, which reflects the poor investment outcomes for the local partner, may also ultimately affect the project debt, as VIP has petitioned to cancel the recent sale of the project's debt to Standard Chartered.

We rate development outcomes as **mixed/negative**. Controversy over the initial (IPTL) agreement and construction costs led to the postponement of the Songas project, which in turn led to inflated (Songas) interest charges. Further, although arbitration reduced the cost of IPTL, the tariff remains significantly higher than the international norm. A delay in the fuel conversion of IPTL (reflecting myriad factors including technological hurdles) has also increased energy charges with IPTL by relying on imported diesel (rather than domestically produced natural gas). Starting in 2002, however, IPTL has been run at near capacity and has helped TANESCO to avoid load shedding as well as the use of potentially more costly 'emergency power'.

11.2. *Songas*. Tanzania's second IPP commenced operations in July 2004, as part of a larger gas project, involving refurbishment and development of offshore gas wells, installation of a gas processing facility, construction of a 232 kilometer pipeline to Dar es Salaam, conversion and expansion of an existing 115 MW power station (Ubungo) from jet fuel to natural gas, the supply of gas for a cement plant, and the development of a larger commercial market for gas. The 190-megawatt, natural gas-fired plant consists of six open-cycle gas turbines (OCGT), which are run on natural gas sourced from the domestic offshore Songo-Songo gas field (four of the turbines were pre-existing and converted to run on natural gas). The Songas project benefited from loans from the World Bank, the European Investment Bank, and Swedish International Development Cooperation Agency. Development of the project took more than a decade.

We rate investment outcomes as **mixed**. Equity turnover has been significant; each of the first two lead equity partners have left the project, in part due to delays. The present lead shareholder, Globeleq, was unable to secure debt financing on the latest addition and ultimately used 100% of its own equity (although refinancing is currently underway). At the same time, despite financial constraints faced by the offtaker, Songas has consistently been paid its capacity charges (due to infusions by the GoT). Furthermore, additional capacity may be installed, thereby increasing Songas' market share.

We rate development outcomes as **mixed**. On the one hand, Songas has contributed to diversifying electricity supply in Tanzania (through the addition of gas-fired generation), and has helped improve the country's security of supply by commercializing previously stranded domestic gas. On the other hand, TANESCO has paid heavily for its new investments, in part due to controversy related to IPTL, which resulted in an accumulation of over US$100 million in interest on the sponsor's equity (also known as the Allowance for Funds Used During Construction, AFUDC).

12. THAILAND.

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

The primary determinants of project outcomes in Thailand are country-level factors such as the structure of the fuel markets, the method of project selection, and the 1997 macroeconomic shock. IPPs in Thailand were (originally) all partnerships between foreign and local investors, firing on natural gas as a main fuel, with similar power sales and fuel supply arrangements. Two coal-fired projects have failed in the face of public environmental opposition. A third coal-fired project (CLP's BCLP project) is only approaching commercial operations in 2006.

In light of these variations, field research in Thailand focused on illuminating the interaction and impact of factors affecting the majority natural-gas fired plants, particularly in exploring the adjustments that investors and governments made in the aftermath of the 1997 crisis. Independent Power Thailand, Ltd. and Eastern Power are discussed in the text as capturing this experience. While in-depth discussions were conducted with investors, project advisors and government officials in Thailand, in-depth case studies on particular projects were not written.

13. TURKEY.

Turkey was potentially an early leader in private power schemes, having authorized private investment in electricity generation in 1984. However, adverse rulings from the country's Constitutional Court classified electricity contracts as concessions, subject to a confusing array of overlapping authority from government agencies, and prohibited recourse to international arbitration. This chilled private investment until a 1994 law exempted BOT arrangements in electricity from the public law requirement and provided long-term power sales contracts with the state utility (TEAS), recourse to international arbitration, and sovereign guarantees for offtake and fuel supply obligations. Six IPPs, responding to solicited bids, signed contracts under this framework before the Constitutional Court struck down the law in 1996.

In 1997 the Turkish Parliament amended the Constitution and passed a BOO law authorizing Treasury-backed long term contracts with TEAS, recourse to international arbitration and other incentives. This BOO framework has attracted an additional 6000 megawatts of competitively bid private generation capacity, at prices reportedly 60% lower than the earlier BOT contracts.

The major recent challenges in Turkey's private power sector stem from the devaluation of the lira—between 1999 and 2002, the Turkish lira suffered a severe devaluation, ushering in a period of stress in the IPP sector, and repeated attempts to renegotiate the dollar-denominated contracts. Thus far, the controversy continues to simmer, but our research has found no major adjustments or disputes.

IPPs in Turkey vary along three variables: fuel choice (coal, hydro, or natural gas), regulatory regime (BOT or BO) and investor composition (foreign and local). The IPP study did not conduct field research in Turkey, however, and instead has relied on public information and stakeholder interviews conducted from abroad. Given this limitation, project selection has been designed to highlight the variation in regulatory regime, which appears to be the dominant factor explaining outcomes in Turkey, and is the key factor from the Turkish experience that is relevant for the IPP study as a whole. In order to isolate as much as possible the effect of regulatory differences, the projects are similar along the other two variables: each uses natural gas a fuel, and each was sponsored by a consortium that included both foreign and local investors. Thus, two projects were selected: Enron's Trakya Elektrik from the first round of BOT projects, and Intergen's trio of projects, Gebze, Adapazari, and Izmir, from the second round of BOO projects.

13.1. *Gebze, Adapazari, and Izmir*. The Gebze, Adapazari, and Izmir projects are three natural gas-fired, combined cycled plants built by Intergen and Enka. Gebze (1555 megawatts) and Adapazari (780 megawatts) began commercial operations in October 2002, and Izmir (1525 megawatts) in February 2003. Taken together, the projects represent the largest private investment ever in the Turkish power sector, and currently provide about 14% of Turkish electricity needs. The projects were built under the second-generation BOO framework, and have sixteen-year PPAs with TEAS, the Turkish transmission monopoly, signed in June 1998, and covered by Turkish Treasury guarantees. The projects also received a priority allocation of gas and non-interruptible supply contracts with the Turkish gas pipeline monopoly BOTAS.

The Intergen-Enka consortium that developed the projects was among a small group of bidders chosen to bid on the first 5 BOO projects offered by the Turkish government in 1997. The consortium was the lowest bidder for all five projects, and was awarded three. The value of the projects, which were financed jointly, was more than $2 billion at financial close. The U.S. Export-Import bank provided full political risk coverage to the participating banks, covering $860 million. OPIC also provided $300 million in capital to the project.

We rate the investment outcome for the three projects as **positive**. Disputes regarding the early BOT projects seem largely to have bypassed the competitively bid BOO projects. Available information indicates that since commercial operations, the contracts have been performed as signed, and our research has discovered no other significant problems. Although Intergen sold all of its IPP assets, the sale was a strategic decision, and did not reflect the performance of specific Intergen assets.

We rate the development outcome as **positive**. Turkey has enjoyed relatively robust power demand growth over the past few years, and these three projects comprise a significant part of the electricity capacity in Turkey. The BOO framework is generally viewed as less expensive than the earlier BOT projects, and the relatively low per/MW cost of the projects confirms this view ($518/MW). Nonetheless, the effect of the progressive devaluation of the Turkish lira has been significant. Industry participants suggest that the relationship between Turkish authorities and the IPPs has been strained. Thus far, however, no major disputes have arisen for Gebze, Adapazari and Izmir.

13.2. *Trakya Elektrik*. Trakya is a 478-megawatt, natural gas-fired, combined-cycle project located in Ereglisi, on the Sea of Marmara. Trakya was one of the first gas-fired BOT plants to achieve financial close and begin commercial operations. Financial close for the $600 million project was reached in late 1996, when Trakya signed a 20-year PPA with TEAS, with the Turkish Treasury fully guaranteeing the payment obligations of the offtaker. The project began commercial operations in June 1999.

Sponsors for Trakya include Enron (50%), Midlands (31%), Gama (10%) and Wing, Intl. (9%). (In March 2004, International Power bought Midlands' stake). Project sponsors provided $150 million in equity, along with a $95 million loan from OPIC, a commercial loan of $120 million from Bayerische Landesbank (to finance the Siemens turbines), and financing from a commercial syndicate that carried a US Export-Import Bank political risk guarantee covering up to $250 million.

There have been substantial disputes in six years of operations. In February 2003, the Turkish government announced that it intended to introduce a protocol for the cancellation of the BOT contracts (but not, apparently, the BOO contracts). It cited the high cost of the electricity generated by the BOT plants, and the fact that the Turkish Treasury was having problems shouldering the contingent liabilities created by the guarantees. In October 2003, the government announced that it was considering seizing the four natural gas BOT plants, Trakya included, on the grounds that there have been "irregularities" in their operations. In November 2003, a study by the state Supervision Agency concluded that that some of the costs being charged to the Turkish government were inappropriate.

We rate the investment outcomes as **positive**. Despite the relatively public disputes, conversations with a former Trakya official indicate that the project has been an investment success. Although full details are not available, this may reflect the fact that the project operated for close to four years before attempts at renegotiation began, and to date appears to have continued operating pursuant to the original contract through the stormy relationship. Given the high risk premiums and lack of competitive bidding that characterized the first round of BOT investment, the project may have extracted substantial returns with six years of operations.

We rate the development outcomes as **mixed**. While Trakya has delivered electricity during a period of rising demand, its cost/MW is more than twice that of Gebze, Adapazari and Izmir. The high cost reflects the lack of competitive bidding, as well as the riskiness of IPP investment during the BOT round when the legal basis for private power ownership was extremely uncertain, and the impact of a macroeconomic shock in 2001.

TABLE 1: PROJECT DETAILS

							Sponsors		Outcomes	
Project Name	Country	Fuel	MW	US$	$/MW	COD	Foreign	Local	Inv't	Dev't
Termoceará	Brazil	Nat'l Gas	290MW	$100	$345	2001	MDU Resources	EBX Capital	Mixed	Negative
Norte Fluminense	Brazil	Nat'l Gas	780MW	$887	$1137	2004	Electricite de France	--	Positive	Mixed
Uruguaiana	Brazil	Nat'l Gas	600MW	$350	$583	2000	AES Corp.	--	Mixed	Mixed
Caña Brava	Brazil	Hydro	450MW	$426	$947	2002	Tractebel Energia	--	Positive	Positive
Shajiao C	China	Coal	1980MW	$1,870	$944	1996	CEPA → Mirant	Guangdong gov't	Positive	Mixed
Meizhouwan	China	Coal	724MW	$755	$1043	2001	Intergen, El Paso, Lippo	--	Negative	Mixed
Shandong Zhonghua	China	Coal	3000MW	$2,200	$733	2003	CLP, EDF	Shandong gov't	Mixed	Mixed
Sidi Krir	Egypt	Nat'l Gas	685MW	$418	$610	2002	Intergen	--	Positive	Positive
Suez	Egypt	Nat'l Gas	683MW	$340	$498	2003	EDF	--	Positive	Positive
Port Said	Egypt	Nat'l Gas	683MW	$338	$495	2002	EDF	--	Positive	Positive
GVK Jegurupadu	India	Nat'l Gas	216MW	$261	$1208	1996	CMS	GVK	Positive	Mixed
Lanco Kondapalli	India	Nat'l Gas	250MW	$285	$1140	2000	CDC Globeleq	Lanco	Positive	Mixed
Essar Power	India	Naphtha/Gas	515MW	$514	$998	1995	--	Essar Steel	Positive	Positive
CLP Paguthan	India	Naphtha/Gas	655MW	$734	$1121	1998	Powergen → CLP	--	Mixed	Mixed
PPN	India	Naphtha/Gas	330MW	$252	$764	2001	El Paso, PSEG, Marubeni	Reddy Group	Negative	Negative
ST-CMS	India	Coal	250MW	$320	$1280	2002	CMS	ST Power	Negative	Negative
IberAfrica	Kenya	Diesel	44MW	$65	$1477	1997	Union Fenosa	KPLC Pension	Positive	Mixed
Tsavo	Kenya	Diesel	75MW	$85	$1133	2001	Cinergy, CDC, Wartsila, IFC	IPS (Agha Khan)	Positive	Mixed
Monterrey III	Mexico	Nat'l Gas	1190MW	$610	$513	2001	Iberdrola	--	Positive	Positive
Rio Bravo II	Mexico	Nat'l Gas	568MW	$234	$412	2002	EDF	--	Positive	Positive
Merida III	Mexico	Nat'l Gas	530MW	$260	$491	2000	AES, Nichimen	Grupo Hermes	Positive	Positive
Navotas I	Phil.	Diesel	210MW	$40	$190	1991	CEPA → Mirant	--	Positive	Positive
Pagbilao	Phil.	Coal	700MW	$888	$1269	1996	CEPA → Mirant	--	Positive	Positive
Quezon	Phil.	Coal	460MW	$895	$1946	2000	Intergen, Ogden	PMR Resources	Positive	Positive
Casecnan	Phil.	Hydro	140MW	$495	$3536	2001	CalEnergy, Peter Kiewit	LA Prairie, San Lorenzo	Mixed	Negative
Cavite	Phil.	Diesel	63MW	$22	$349	1995	CMS → Covanta	--	Negative	Negative
ENS	Poland	Nat'l Gas	116MW	$132	$1138	2000	Enron (Prisma)	JAC International	Positive	Mixed
Elcho	Poland	Coal	220MW	$324	$1473	2003	PSEG	EC Chorzow	Mixed	Negative
Songas	Tanzania	Nat'l Gas	190MW	$130	$684	2004	OTC → AES, IFC, CDC	--	Mixed	Mixed
IPTL	Tanzania	Diesel	100MW	$127	$1270	2002	Mechmar	VIP Engineering	Mixed	Mixed
Eastern Power	Thailand	Nat'l Gas	350MW	$250	$714	2003	Marubeni	GMS	Positive	Positive
Independent Power	Thailand	Nat'l Gas	700MW	$369	$527	2000	Unocal, Westinghouse	Thai Oil	Positive	Positive
Gebze, Adapazari, Izmir	Turkey	Nat'l Gas	3860MW	$2000	$518	2002	Intergen	Enka	Positive	Positive
Trakya Elektrik	Turkey	Nat'l Gas	478MW	$600	$1255	1999	Enron (Prisma)	Gama	Positive	Mixed