Small Power Purchase Agreement Application for Renewable Energy Development: Lessons from Five Asian Countries

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Contents

Tables

FOREWORD

Asia has the largest population and fastest rate of growth of new electricity supply of any continent. How Asian nations elect to provide new electric generation capacity to meet this inevitable growth in electricity demand will have profound implications for their societies, for world energy use, and for environmental quality.

Various renewable energy technologies are particularly appropriate options for developing nations that are evaluating how best to extend electric service and generating capacity. Several Asian nations have pioneered small power programs to encourage independent renewable power generation. The World Bank Group has played a supportive role in some of these programs. There is now a decade of experience in such programs in Asia.

What these programs have demonstrated is that there are certain common elements and characteristics in Asian small power programs. This is because the fundamental legal relationships necessary to establish a power sale relationship and provide credit support for an independent power project follow a predictable legal pattern. Yet, each Asian experience has been tailored to local conditions and requirements. Some have introduced innovative bidding, competitive, or incentive structures. The result is a rich palette of experience with small power projects in Asia.

This report analyzes experience in six SPP programs in five nations in Asia. In an easily accessible manner, it compares and contrasts program design, power purchase agreements, and tariff design in these programs. Professor Ferrey critiques what has worked best, what innovative program design has been tried, and successful program design practices. It covers the power purchase agreement, the tariff in that agreement, program design, and innovative options.

This report is an important resource for nations contemplating small power programs, independent power programs, and promotion of renewable energy technologies. It also provides a template for what innovative features have had positive impacts, what elements have caused some programs to hit barriers, and what elements of program design have lasting and transcendent value for other programs. It is a resource for all nations embarking on or augmenting small power or renewable energy projects.

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ABSTRACT

Five innovative nations in Asia have been among the first in developing small power producer (SPP) programs to promote renewable energy development in-country. These programs have been very successful in some of these nations in promoting during just a few years a substantial contribution of renewable small power projects to the national energy supply. Almost 4 percent of power supply in India and Thailand are from SPP renewable energy initiatives.[1]

In the Overview and in the discussion of each country that follows, this report identifies the most successful program features, innovative elements, and power purchase agreement (PPA) design provisions that have achieved notable success and that could be the basis of programs in other nations. This report evaluates what has worked best and what mistakes are to be avoided. It is designed to transfer the legal "technology" of how to create a PPA and SPP program to most efficiently accomplish renewable energy and small power program goals.

Although each of these nations' programs has certain elements in common, important distinctions exist between them. Each of these programs involves standardized power purchase agreements (PPAs) or standardized tariffs, or both, which are a material element of program design. Many of these countries advanced their programs with technical and/or financial assistance from the World Bank or other international agencies, although the Thailand program proceeded without such assistance.

The **Thai** program operates in tranches of formal solicitation by the state utility. Eligible projects mirror the requirements of those of the PURPA program in the United States, with size limitations up to 60 MW, and in some cases, 90 MW.[2] State subsidies are provided for some renewable SPPs competitively selected. As in the U.S. experience, the majority of projects are natural gas-fired cogeneration projects. Both firm and nonfirm PPAs are available. The contract was designed to be indexed, but instead is adjusted periodically for foreign exchange risk for capacity and energy payments. For intermittent renewable projects, the capacity factor must be greater than 0.5, without a reduction in capacity payments. Thailand was the first of the Asian SPP programs, and it set a standard for successful program development. A noteworthy feature is its competitively determined renewable SPP subsidy program.

The **Indonesian** began to develop a program in 1993. It came to involve a standardized PPA and tariff. The SPP program was designed to supply up to one-third of national new power supply from small, renewable sources, organized into four tiers of priority for projects of up to 30 MW in size on the primary island, and half that size on smaller island grids. Because Indonesia comprises several separate and not interconnected island grid systems and isolated diesel systems, this program design was nuanced and disaggregated to address avoided cost and power requirements on a regional basis.

The standardized PPA in its original design contemplated either a firm or nonfirm power sale. The incentives for firm power delivery were embodied in the tariff, with indexation of capacity payments for foreign exchange risk, on the theory that most of the value added of generating capacity would be foreign production (this program included cogeneration utilizing fossil fuels as a lower-priority generation source). This provided an innovative approach to structuring the performance obligation, whereby no legal sanctions were imposed for performance failure of the SPP, but rather a substantial economic

[1] For statistics on the Thai and Sri Lanka programs, see EGAT (2003) and Energy Services Delivery Project (2002).

[2] For a detailed evaluation of the PURPA program, see Ferrey (2000), chapters 5–6, and Ferrey (2003), chapter 4.

disincentive for the SPP from such nonperformance was in place. Some innovative fuel price hedging was provided for renewable power projects.

In **India,** each state makes its own determinations about SPP programs. Two representative Indian states were evaluated. Although some Indian states provided formal SPP solicitations or allowed direct retail third-party sales, or both, neither of the two states evaluated here now allow direct third-party sales or conduct a formal project solicitation.

In the state of **Andhra Pradesh**, no formally standardized contract is in place, although de facto a set contract form is used by the utility, leaving some case-by-case discretion with the utility. The tariff is escalated at 5 percent annually from a base year. Moreover, the tariff can be reset midcontract after three years by the government. This undercuts long-term certainty. Energy wheeling is allowed, but discouraged economically by a high wheeling charge. No third-party retail sales are allowed.

In **Tamil Nadu** state, a similar de facto set PPA is employed. An SPP is defined as any project up to 25 MW. Many wind power projects have been developed and grid connected. Wheeling of power to an affiliated location—not to a third-party—is permitted with a 2 percent charge. No third-party retail sales are allowed.

The **Sri Lankan** program does not utilize a simultaneous solicitation for SPP bids as was deployed in Indonesia and Thailand. Ad hoc offers are entertained by the state utility. Fifteen-year PPAs are available for projects up to 10 MW in size. All but one of the successful SPPs to date are small hydroelectric projects. The PPA is standardized, as is the tariff. The tariff development was assisted by consultants provided by the World Bank. The tariff is revised annually based on a three-year fuel average, with a tariff floor of 90 percent of the original tariff underneath renewable projects.

The tariff as eventually implemented is not indexed for foreign exchange risk. It is paid in local currency on a kWh-delivered basis, which employs economic incentives rather than contract coercion to provide incentives for SPP delivery of power.[3] This tariff structure embodies the incentives for performance in the tariff itself, unlike the tariff proposed for Vietnam. Even if the SPP delivers capacity, it is only paid for energy, although at prices that have increased significantly over time in both nominal and real terms. Financing of projects is available with assistance from the World Bank through local banks.

The SPP program in **Vietnam** is still in the design phase. The proposed PPA employs a concept of "deemed" energy as a means to pay separately the capacity component of power sold. "Deemed" energy output obligates the utility to pay for the capacity component of power whether or not it takes any of that power. The recommended tariff is not structured to induce maximum production and delivery of power, because the financial incentives are not built into the energy component of the obligation. The Vietnam program promises to be of keen interest if it is successfully launched.

These five Asian nations offer different forms of government and have different predominant fuel sources in their generation base (hydro, coal, gas, oil). Some of the national electric systems have an integrated high-voltage transmission system, whereas others have a disintegrated or island system, but there are key similarities:

- All are in need of long-term increases in power generation capacity (although Thailand has a short-term current surplus).

[3] With significant inflation of the local currency against the U.S. dollar during the program period, there has been significant deterioration of the value of the energy payments in constant foreign currency equivalent. The SPP projects in Sri Lanka are hydroelectric, and therefore have a significant local component of the cost of capacity development.

- All have the potential of small-scale renewable energy options.
- Each country is being approached by private developers who seek to develop renewable SPP projects.
- Each system employs either deliberately or de facto a standardized PPA, although it is not necessarily a neutral or consensual document in all cases.
- Although avoided cost concepts for establishing the SPP tariff are recognized in each nation, avoided cost concepts are applied differently in these nations' SPP programs.

There are some interesting common elements on tariff design. Indexation to foreign exchange rates was contemplated in most instances, but ultimately not implemented. Most of the programs have elected not to index their tariffs to foreign exchange (Thailand's capacity payment is an exception). In some Indian states, the tariff is indexed to inflation to keep value in international currency amid local inflation. Other countries unilaterally review and may adjust the tariff at a prescribed time. The purpose of this adjustment is to reflect changes in the energy component of the tariff, which changes both as marginal fuel costs change, as well as when foreign currency rates change and the marginal fuel is an imported commodity for the country. Although important, this periodic adjustment does not provide long-term predictability for project finance or equity investment.

Although these SPP programs are designed to equalize some of the monopsony power and create a more level playing field, the experience in several nations indicates that where the utility is the only legal buyer of SPP power, the overwhelming advantage in bargaining power enjoyed by the utility must be balanced by a carefully designed and faithfully administered SPP program. Several important lessons for SPP program design and policy were revealed by analyzing these programs:

- A framework for structured SPP project development is necessary. SPPs do not spring full-borne from the existing electric sector environment. A system of law, regulation, and utility interface that facilitates orderly SPP development must exist.
- A transparent process is required to build investor, developer, and lender confidence.
- An SPP program can be initiated and sustained either by an open offer to execute PPAs, or by an ordered and time-limited solicitation process.
    - An open offer allows a constant rolling development of SPPs, much like the original PURPA design in the United States.
    - An ordered solicitation can inject competitive bidding which, if correctly administered, results in bid price reduction and competition for the best projects and sites.
- The single state buyer of power in most of the electric sectors can more robustly and efficiently promote renewable SPPs, either by (a) a program for purchase of all SPP power at its full value (avoided cost) to the wholesale system, or (b) the introduction of some combination of third-party retail sales, net metering–energy banking, or third-party wheeling.
- Utilities must interconnect with SPPs subject to a straightforward procedure.
- In systems experiencing current and projected shortages of grid-connected power resources, payment of long-term full avoided cost (including capacity and energy) for renewable energy and small power development can accelerate the deployment of renewable facilities utilizing "free" fuel (for example, solar, wind, flowing water, or agricultural waste) that otherwise is wasted.
- In many systems, additional subsidies, reflecting the fuel diversity and environmental advantages, are utilized to assist higher-cost renewable energy and smaller SPP projects.

- Bidding can be employed strategically to minimize the ultimate system cost to the buyer of renewable power resource development.
- The SPP PPA tariff in the Indonesian, Thai, and Sri Lankan programs was designed to include capacity payments in the tariff payment for each kWh delivered, paid only if the SPP delivers power. This was designed to provide the maximum incentive to the SPP for dedicated performance and delivery of power at peak periods, while not invoking any coercive penalties against the SPP for failure to perform to a set standard.

None of these five Asian programs currently allows direct third-party retail sales of power by the SPP. Thailand, which led the initial development of Asian PPAs, is considering moving toward an open market for third-party sales. This is allowed in other Indian states. It will likely be reevaluated in many nations as power systems are privatized, operating concessions created, and wholesale competition introduced.

A recent innovation in half the states in the United States is known as "net metering." Net metering provides an incentive for SPPs by allowing them to "exchange" power they produce and sell with the utility during a billing period with power that they or their affiliates take from the utility.[4] In the United States, net metering, implemented at the state level, is now regarded as the most significant incentive among several incentives to promote renewable energy distributed generation. Each of the states that have adopted some form of net metering is evaluated in a separate report prepared by the author. Net metering and energy banking have application to these Asian programs that are experimenting with innovative mechanisms to allow SPPs to achieve credit support and attract private capital.

[4] This buy and sell is netted at the end of the billing period. Because the fully loaded retail price at which a utility sells power to the SPP typically is much greater than the wholesale avoided cost price at which the utility purchases power, this net metering results in the SPP being able to sell an amount of its power output at a price that exceeds the utility's avoided cost. This provides a significant subsidy of the SPP operation through the net metering exchange. Most net metering applies exclusively to renewable generation and, in more limited situations, to fuel cells or cogeneration, or both.

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He is the author of five books, including *The Law of Independent Power, now in its 20th edition* (Ferrey 2003), a book used throughout the world by energy law firms, governments and regulators involved in the power sector. Also among his books are *The New Rules: A Guide to Electric Market Regulation* and *Environmental Law*, as well as more than 50 articles and book chapters about energy and environmental policy. He holds a B.A. degree in economics from Pomona College and J.D. and M.A. degrees from the University of California at Berkeley, and was a postdoctoral Fulbright Fellow in energy studies at the University of London.

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EXCHANGE RATES

(as of June 2003)

1 U.S. dollar = 42.77 Thai bhat
1 U.S. dollar = 47.52 Indian rupees; 1 lakh = 100,000 rupees;
1 crore = 10 million rupees
1 U.S. dollar = 96.86 Sri Lankan rupees
1 U.S. dollar = 8,845 Indonesian rupiahs
1 U.S. dollar = 15,426 Vietnamese dong
$ is assumed to be U.S. dollars throughout.

ACRONYMS, ABBREVIATIONS, AND DEFINITIONS

ADB	Asian Development Bank
APERC	Andhra Pradesh Electricity Regulatory Commission
APSEB	Andhra Pradesh State Electricity Board
APTransco	Transmission Corporation of Andhra Pradesh Limited
ASTAE	Asia Alternative Energy Program
Avoided cost	The cost that a purchaser would pay if it generated or purchased power from external sources or at market rates
BOOT	Build-own-operate-transfer
Capacity	Electric generation capacity firmly committed for a period of time
CEB	Ceylon Electricity Board (Sri Lanka)
Cogeneration	The production of electricity and heat from a common source
DANIDA	Danish International Development Agency
DGEED	Directory General of Electricity and Energy Development (Indonesia)
Dispatchable power	Power from an electric power generator that can be controlled usually by the purchasing utility as to its time or quantity of power output
ENCON	Energy Conservation Promotion Fund Committee (Thailand)
Energy	Kilowatt-hours of power not firmly committed long-term to a particular use or sale
EGAT	Electricity Generation Authority of Thailand
EPO	Energy Policy Office (Thailand)
EVN	Electricity of Vietnam
FDR	Fixed deposit receipt
Firm power	Power that is contractually committed to a particular use or purpose
GEF	Global Environment Facility
Gigawatt	1 million kilowatts (kW)
GWh	Gigawatt-hour
IBRD	International Bank for Reconstruction and Development (World Bank)
IDA	International Development Agency
IEC	Electro-technical Commission
IPP	Independent power producer
IREDA	Indian Renewable Energy Development Agency
IUKU	Electric Power Enterprise Permit (Indonesia)
KfW	Kreditanstalt für Wiederaufbau (Bank for Reconstruction; Germany)
kW	Kilowatt

kWh	Kilowatt-hour
LoI	Letter of Intent
Marginal cost	The cost of providing the next kilowatt-hour or kilowatt of power, or both
MNES	Ministry of Non-Conventional Energy Sources (India)
MW	Megawatt
MWh	Megawatt-hour
NEDCAP	Non-Conventional Energy Development Corporation of Andhra Pradesh (India)
Nonfirm power	Power that is not dedicated long-term to a particular buyer and which the seller has no contractual obligation to produce
NGO	Nongovernmental organization
O&M	Operation and maintenance
OECF	Overseas Economic Cooperation Fund (Japan)
Off-peak	Periods of relatively low system demand by day or by season
PCF	Prototype Carbon Fund
Peak	Periods of relatively high system demand by day or by season
PLN	Pursahan Listrik Negara (Indonesian State Electricity Corporation Ltd., Indonesia)
PPA	Power purchase agreement
Prime mover	The technology to convert chemical energy to mechanical energy, such as gas turbines or combined cycle units
PURPA	Public Utility Regulatory Policies Act, a U.S. energy statute
PV	Photovoltaic(s)
Renewables or renewable energy	Renewable energy sources that can be replenished by naturally occurring processes in daily cycles
Retail competition	A system where more than one electrical provider can sell to retail customers and such customers have choice of their providers
Retail wheeling	The ability of a power generator to use the national transmission grid to move power to itself (self-service wheeling) or others at locations remote from the generator
Rp.	Indonesia rupiah
Rs.	Indian rupee
SL Rs.	Sri Lankan rupee
SPP	Small power producer
T&D	Transmission and distribution
TNEB	Tamil Nadu Electricity Board (India)
TRANSCO	Transmission company
Wheeling	The transmission of electricity by an entity that does not own the power

1. Overview and Summary

Important developments in the implementation of renewable power generation projects have occurred in five Asian nations between 1993 and 2003. Five nations in Asia have been among the first in developing small power producer (SPP) programs to promote renewable energy development in their countries. The purpose of each of these SPP programs is to promote renewable electric power development, which often is deployed in the form of distributed generation.

Some programs have been successful and have created important models. These programs have features that are important markers and lessons on how to implement such programs. They have achieved in just a few years a substantial contribution of renewable small power projects to the national energy supply: 2 percent of power supply in Sri Lanka, and almost 4 percent in India and Thailand, are from SPP renewable energy initiatives.[5] Power development in Asia is an important global environmental and resource laboratory: Approximately 60 percent of all new power generation capacity financed in developing countries is in Asia.[6] Therefore, how and what energy resources are deployed in Asia have long-term implications for global environmental integrity.

Although each of these nations' programs has certain elements in common, important distinctions exist between them. This report analyzes these programs in five nations: India, Indonesia, Sri Lanka Thailand, and Vietnam. Many of these countries advanced their programs with technical and/or financial assistance from the World Bank or other international agencies, although the Thai program proceeded without such assistance. Many of these programs involve standardized power purchase agreements (PPAs) or standardized tariffs, or both, which are material elements of program design.

This report evaluates the small power supply programs established or in the course of being established in a cross-section of five Asian nations that have advanced such programs (including two different states in India) against the requirements of project finance and equity capital. These different programs do not always reflect differences in native program requirements. Rather, they typically reflect deliberate program policy choices. These programs are at different stages of development. This report reflects the feedback of various stakeholders in the private power process in these countries. This evaluation highlights those program differences and contrasts, which have both augmented the realization of SPP program objectives and which have proven to be missteps for future program success.

In addition, key provisions and legal structure of the standardized PPAs in each of these countries are evaluated. Each of these programs has used a standardized PPA—some have deliberately created it, whereas others have used a utility PPA that has been implemented unilaterally as a standardized contract format. The PPAs are analyzed as to

- Basic structure.
- The elements of power sale and metering.
- Allocation of various risk parameters among the parties to the PPA.
- Interconnection and transmission provisions.
- Tariff and price design for the power sale transaction.

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[5] For statistics on the Thai and Sri Lanka programs, see EGAT (2003) and Energy Services Delivery Project (2002), respectively. Alternatively, http://www.boi.lk lists incentive investment details for Sri Lanka. A review of programs, tender notices, and a series of reports on the India program is available at www.MNES.nic.in.
[6] World Bank (1998), p. 1.

- Parameters of SPP operation and breadth of obligation.
- Dispute resolution.

In each of the countries with a designed rather than de facto standardized PPA, consultants recommended a design and legal draft for the PPA. In each instance, they recommended a structure that relied on prior successful experience in the United States and other Asian countries. The basic conclusions for each of the programs are briefly summarized below.

Some of these early programs have elements modeled on PURPA experience in the United States. Some of the recommendations for later programs incorporate ad hoc elements of some earlier programs. The lessons of these various programs have never been catalogued and critiqued for implementation of best practices in program design and structure of the contractual PPA relationship. Table 1 displays salient comparative elements of program design and implementation in five of the programs surveyed. Vietnam is not listed in the table because its program is not yet finalized or implemented.

Two columns in this table are noted. First, two of the five profiled programs subsidize renewable energy SPPs. Thailand does so by providing a project-specific subsidy through a competitive solicitation process. Andhra Pradesh does so by providing a tariff in excess of true avoided cost for renewable energy SPPs. The final column illustrates that some programs have an open offer to enter a PPA that the SPP may accept. There is an outstanding PPA offer for SPPs to accept. Other countries which more carefully ration the PPA opportunities utilize a controlled solicitation of offers from prospective PPAs to award PPAs. In this situation, the SPP makes an offer or bid to the utility, which the utility may or may not accept.

Table 1: Comparative Program Overview

Country Program	*Year begun*	*Maximum size (MW)*	*Premium for renewable energy*	*Primary fuel*	*Eligible PPA solicitation*
Thailand	1992	<60 or <90	Yes, competitive bid	Gas	Controlled period
Indonesia	1993	<30 Java <15 other island grids	No	Renewable Energy	Controlled period
Sri Lanka	1998	<10	No	Hydro	Open offer
India: Andhra Pradesh	1995	<20 Prior <50	Yes, in tariff	Wind	Open offer
India: Tamil Nadu	1995	< 50	No	Wind	Open offer

Table 2 displays salient comparative elements of PPA design and contractual entitlement in five of the programs surveyed.

Table 2: Comparative PPA Elements

Country program	*Standard PPA?*	*Maximum years*	*Third-party sales*	*Self-service wheeling*	*Net meter–banking*
Thailand	Yes	20–25 firm 5 nonfirm	No, under consideration	No, under consideration	Yes, if <1 MW

Country program	*Standard PPA?*	*Maximum years*	*Third-party sales*	*Self-service wheeling*	*Net meter–banking*
Indonesia	Yes	20 firm 5 nonfirm	No	Yes	No
Sri Lanka	Yes	15	No	No	No
India: Andhra Pradesh	Not formally, but a de facto standardized form	20	No, previously allowed	Yes, but very expensive	Yes
India: Tamil Nadu	In development	5–15	No, previously allowed	Yes	Yes

Note the differing and evolving policies in different programs on direct SPP retail third-party sales, self-wheeling and net metering or energy banking. Table 3 displays salient comparative elements of the PPA tariff in the SPP program.

Table 3: Comparative Tariff Elements

Country program	*Avoided cost basis*	*Indexed to foreign currency*	*Periodically adjusted*	*Design elements*
Thailand	Yes, energy and capacity payment for firm contracts only	No	Yes	Utility purchases 65% of off-peak power
Indonesia	Yes, both energy and capacity	Yes	Yes, for changes in avoided capacity cost	Steep on-peak incentives; differentiated for each island grid
Sri Lanka	Yes, energy only; nondispatchable units receive less than full avoided energy cost	Not directly, but price linked to dollar-denominated imported oil price	Yes, and includes foreign fuel component	Calculated annually, based on three-year moving average imported oil price
Andhra Pradesh	Yes, not to exceed 90% of retail tariff	No	Yes	Reset every three years
Tamil Nadu	Exceeds avoided cost	No	Yes	Higher tariff for biomass than wind

Note that the avoided cost concept and a standardized PPA are generally utilized. This is consistent with the still-in-place PURPA requirements in the United States. Avoided cost is generally deemed the equitable point where the utility system gets power at its opportunity cost of alternative power supply. Retail consumers also are indifferent between utility supply and SPP supply if the avoided cost is paid for this power on a wholesale basis. However, not every program pays the long-term avoided cost for long-term firm power commitments. Although some programs differentiate long- and short-term avoided costs depending on the firm or nonfirm structure of the PPA, some countries only pay short-term energy-only avoided cost regardless of the nature of the PPA obligation.

Some programs have varied or capped the avoided cost concept. The Indian state programs cap the tariff at 90 percent of the industrial retail tariff; the Sri Lankan program caps the tariff paid to nondispatchable providers. All programs periodically adjust the tariff. This is necessary, at the least, to reflect changes in marginal costs of fuel, a significant element of avoided energy cost. Some programs have indexed their tariffs to foreign exchange, such as the Thai program for avoided capacity; most adjust their tariffs periodically, based on different criteria.

There is significant diversity in the tariff design. Indonesia steeply incentivizes on-peak hourly delivery of SPP power, correspondingly decreasing off-peak hourly prices for SPP power deliveries, so that the weighted average tariff equals avoided cost. This promotes market solutions and deemphasizes the necessity for contract remedies and default requirements. Sri Lanka employs a seasonally differentiated tariff to reflect peak system premium requirements. Tamil Nadu provides a higher tariff to base loaded biomass projects than it does to intermittent wind projects.

Each of the programs is briefly summarized below on several primary features. Subsequently, in the sections that follow, each program is analyzed in detail.

Thailand Program Summary

The **Thai** program operates in tranches of formal solicitation by the state utility. Eligible projects mirror the requirements of those of the PURPA program in the United States, with size limitations up to 60 MW, and in some cases, 90 MW.[7] State subsidies are provided on a competitive bidding basis that allows the maximum leverage of renewable SPP resources at the lowest kWh cost to the state. The process operates by an amount of renewable energy subsidy being set aside by the state. Against a maximum subsidy, prospective SPPs bid for the amount of subsidy per kWh that they require to enter a PPA with Energy Generating Authority of Thailand (EGAT), the utility. SPPs are awarded subsidy in the order of the lowest SPP subsidy bid, until the gross subsidy allocation is exhausted. Thus, the competitive bidding process is employed to ration and stretch government subsidies.

This competitive bidding process may be the most important lesson of the Thai program. The ultimate price paid by EGAT for small renewable power is a function of two price components: a fixed energy price plus a competitively bid and set renewable energy subsidy. By having potential renewable energy projects bid for the amount of subsidy they require, the least-cost (subsidy) renewable projects are selected. This rations the projects so that the most cost-effective are selected, and also stretches the available pool of subsidy dollars over the most megawatts of renewable power. Although the general energy price is based on utility avoided cost, the small subsidy for successful renewable energy projects provides a premium above avoided cost. In return, the system benefits from the fuel source and supply diversity that these projects provide.

As in the U.S. experience, the majority of projects are natural gas–fired IPP cogeneration projects. Both firm and nonfirm PPAs are available. The contract was designed to be indexed, but instead is adjusted periodically, for foreign exchange risk for capacity payments and fuel price changes for energy payments. For intermittent renewable projects, the capacity factor must be greater than 0.5, without a reduction in capacity payments. Thailand was the first of the Asian SPP programs, and it set a standard for successful program development.

Table 4 sets forth in abbreviated format the primary program design, tariff, and contract provisions of the Thai SPP program, including its innovative renewable subsidy incentive.

Table 4: Primary Elements of the Thai SPP Program

1. **Process:** Controlled solicitation.

[7] For a detailed evaluation of the PURPA program, see Ferrey (2000), chapters 5–6, and Ferrey (2003), chapter 4.

2. **Maximum Size:** 60 MW (90 MW with permission).
3. **Tariff:** Avoided cost to utility.
   For firm 20-year energy and capacity:
   Coal: $0.04 per kWh.
   Gas and Renewables: 2.14 baht per kWh assuming 85% capacity factor [$0.051 per kWh (2003 exchange rates).
4. **Third-party retail sales:** No. Under consideration.
5. **Self-wheeling:** No. Under consideration.
6. **Energy banking:** Only for SPPs < 1 MW.
7. **Standardized PPA:** Yes. After 2001, because of excess capacity, EGAT purchases 100% of capacity rating of kWh on peak and 65% of capacity rating kWh off-peak. Therefore, project cannot supply and be paid for rated capability during off-peak periods.
8. **PPA term:** Firm, 5–25 years Nonfirm, < 5 years.
9. **Subsidy or incentives:** Competitive bidding for five-year renewable subsidy.
   Up to $0.009 per kWh based on lowest bids.
   Eight-year income tax holiday.
   Equipment exempt from import tax.

Indonesia Program Summary

The **Indonesian** program began its development in 1993. It came to involve a standardized PPA and tariff. The SPP program was designed to supply up to one-third of national new power supply capacity additions from small, renewable sources, organized into four tiers of priority for project of up to 30 MW in size on the primary island, and half that size on smaller island grids. Because Indonesia comprises several separate and not interconnected island grid systems and isolated diesel systems, this program design was nuanced and disaggregated to address avoided cost and power requirements on a regional basis.

The standardized PPA in its original design contemplated either a firm or nonfirm power sale. The incentives for firm power delivery were embodied in the tariff, with indexation of capacity payments for foreign exchange risk, on the theory that most of the value added (cost) of generating capacity would be foreign-manufactured turbines and generator sets (this program included cogeneration utilizing fossil fuels as a lower priority generation source). Therefore, conventional industrial cogeneration, as well as renewable resources, were eligible for this program. This provided an innovative approach to structuring the performance obligation, whereby sanctions without a legal basis were imposed for performance failure of the SPP. These sanctions were accompanied by economic shortfalls for the SPP from such nonperformance. Some innovative fuel price hedging was provided for renewable power projects.

Two lasting lessons of the Indonesian program design are (a) that disaggregated PPA provisions and tariffs can be designed to address different regional grids and requirements, and (b) that PPA and tariff incentives can be designed to provide profound financial incentives for SPP delivery of power at peak times. This latter element allows the PPA to avoid typically stringent sanctions and penalties for failure to perform on-peak: Market incentives are substituted for the traditional “command-and-control” legal sanctions.

The 1997 Asian financial crisis ended the chances for program implementation in Indonesia, just as this SPP program was rolling out. Indonesia found itself oversubscribed in IPP power obligated on a noncompetitive basis at above-market prices amid falling demand in the face of economic crisis, and consequently did not follow through on SPP contracts. The Indonesian State Electricity Corporation Ltd. (PLN) became a noncreditworthy party as a long-term power purchaser. Unilateral changes in the PPAs by the utility also resulted in a final PPA that was unfinanceable without modification. Not a single megawatt of power has yet to be brought to market under this program.

Table 5 sets forth in abbreviated format the regulatory system, tariff, and contract characteristics of the Indonesian SPP system, including its tariff differentiation for peak-period power delivery.

Table 5: Primary Elements of the Indonesia SPP Program

1. **Process:** Controlled solicitation.
   Renewables and renewable cogeneration given highest priority.
2. **Maximum size:** 30 MW on Java-Bali; 15 MW on 7 other island systems.
3. **Tariff:** Avoided cost for each island system.
   For firm renewable energy and capacity:

	$ per kWh (1995)		
	On-peak	*Off-peak*	*Weighted average*
Java-Bali	$0.155	$0.04	$0.059
Other islands	$0.17	$0.05	$0.07

   The dramatic devaluation of the rupiah since these tariffs were calculated caused withdrawal of the tariff during the Asian financial crisis. Because of the drastic devaluation of the rupiah, the above 1995 prices are not expressed in rupiahs.
   95% (of year 1) floor under renewable SPP energy price in future years (not inflation adjusted), whereas energy price can increase with marginal system fuel prices year to year; capacity price adjusted by the U.S. dollar–to–rupiah exchange rate for five years.
4. **Third-party retail sales:** No.
5. **Self-wheeling:** Allowed with permission.
6. **Energy banking:** No.
7. **Standardized PPA:** Yes.
8. **PPA term:** Firm, 5–20 years Nonfirm, < 5 years.
9. **Subsidy or incentives:** Steeply incentivized on-peak tariff.
   Exemption from import duties and certain income taxes.
   Postponement of the value added tax and sales tax on luxury goods.

India Program Summary

In **India,** each state makes its own determinations about SPP programs, subject to federal incentives and guidance. Two representative Indian states are evaluated. Although some Indian states provided formal SPP solicitations or allow direct retail third-party sales, or both, neither of the two states evaluated here now allows direct third-party sales or conducts a formal project solicitation. What distinguish the Indian SPP programs are their flexible and creative deployment of federal and state renewable energy subsidies and financing programs, which have combined to create a highly successful SPP program.

In mid-2003, the federal Electricity Act of 2003 was enacted.[8] It consolidates the electricity laws and regulation embodied in federal legislation. It requires a license to generate and distribute electricity, except that in rural areas, no such license is required as long as the distributor follows any pre-established

[8] The Electricity Act of 2003 aimed "to consolidate the laws relating to generation, transmission, distribution, trading and use of electricity…promoting competition…promotion of efficient and environmentally benign policies…."

requirements of the Central Electric Authority. Any generating company may construct and operate a generator without obtaining a license, as long as technical grid standards are observed.[9] Transmission, distribution, and trading of electricity require a government license.[10] State commissions are directed by the Act to facilitate the transmission, wheeling, and interconnection of electricity within the state.[11]

Andhra Pradesh Program Summary

In Andhra Pradesh state, there is no formally standardized PPA, but the utility employed a similar contract in all SPP transactions, thus making a de facto standardized PPA contract, while still leaving extensive case-by-case discretion with the utility regarding which contracts to enter. The tariff, although among the highest in India, and escalated at 5 percent annually from a base year, does not exceed 90 percent of the high-tension retail tariff. Moreover, the tariff can be reset midcontract after three years by the government. This makes for little project certainty and is a major problem cited by project developers.

Table 6 sets forth in abbreviated format relevant SPP provisions of the SPP program and tariff in Andhra Pradesh, including the significant wheeling fee.

Table 6: Primary Elements of the Andhra Pradesh SPP Program

1. **Process:** Open offer.
2. **Maximum size:** < 20 MW (was < 50 MW).
3. **Tariff:** Above avoided cost to utility not to exceed 90% of industrial retail tariff.
   2003: Rs. 3.32 per kWh [$0.0698 per kWh]
4. **Third-party retail sales:** No (previously allowed).
5. **Self-wheeling:** Allowed with 28% wheeling fee plus $0.01 per kWh charge.
6. **Energy banking:** Allowed with 2% energy banking charge.
7. **Standardized PPA:** Yes.
8. **PPA term:** 20 years.
9. **Subsidy or incentives:** Federal loans with 1- to 3-year repayment moratorium.
   80% of capital cost can be depreciated against taxes in the first year.
   Grants for PV systems.
   Equipment exempt from sales tax.

Tamil Nadu Program Summary

In Tamil Nadu state, no formal standardized PPA is employed, although the utility has employed the same PPA of its design in every situation, thereby creating a de facto standardized PPA. This again leaves great discretion with the utility. Wheeling of power to an affiliated location—not to a third-party—is permitted. An SPP is defined as any project up to 25 MW. The tariff is higher for biomass projects than for wind. There is no sovereign or currency risk hedge mechanism.

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[9] Electricity Act (2003), Section 7, p. 9. Certain conditions are imposed on the development of hydroelectric generations to ensure the highest use of water resources for competing uses. Electricity Act (2003), Section 8, p. 9.

[10] Electricity Act (2003), Section 12, p. 11. Conditions may be imposed on the license. Electricity Act (2003), Section 16, p. 13.

[11] Electricity Act (2003), Section 30, p. 19. An appellate tribunal also is established to handle appeals of an order of the regulatory commissions. Electricity Act (2003), Section 110, p. 53. State governments are authorized to constitute special courts to expedite trials of those who steal or divert electricity. Electricity Act (2003), Section 153, p. 68.

Table 7 sets forth in abbreviated format salient elements of the Tamil Nadu SPP program, including its low wheeling charge.

Table 7: Primary Elements of the Tamil Nadu SPP Program

1. **Process:** Open offer.
2. **Maximum size:** < 50 MW.
3. **Tariff:** Above avoided cost to utility not to exceed 90% of industrial retail tariff.
   Wind: Rs. 2.7 per kWh [$0.057 per kWh] 2003.
   Biomass: Rs. 2.88 per kWh [$0.06 per kWh] 2003.
4. **Third-party retail sales:** No (previously allowed).
5. **Self-wheeling:** Allowed with 2% wheeling charge for up to 25 km transmission; 10% wheeling charge more than 25 km.
6. **Energy banking:** Allowed with 2% banking charge.
7. **Standardized PPA:** Yes, in final development.
8. **PPA term:** 5–15 years.
9. **Subsidy or incentives:**
   80% of capital cost can be depreciated against taxes in the first year.
   Grants for PV systems.
   Equipment exempt from sales tax.

Sri Lanka Program Summary

The **Sri Lanka** program has not utilized a simultaneous solicitation for SPP bids as was deployed in Indonesia and Thailand. Ad hoc offers were entertained by the state utility. In 2003 the program was modified to adopt a controlled solicitation process, with application fees and earnest money deposits from PPA recipients. Letters of Intent (LoIs) to successful bidders are now valid for only six months. This prevents award recipients from attempting to prospect for hydroelectric sites for which they have no resources to develop, and once controlling these rights, trying to sell them to other developers.

Fifteen-year PPAs are available for projects up to 10 MW in size. All successful SPPs to date are small hydroelectric projects. The PPA is standardized, as is the tariff. Consultants provided by the World Bank assisted the tariff development. The tariff is revised annually based on a three-year moving average fuel price, with a tariff floor of 90 percent of the original tariff underneath renewable project energy payment adjustments.

The tariff as eventually implemented is not indexed for foreign exchange risk, although it reflects the cost of imported fuel priced in foreign currency. It is paid in local currency on a kWh-delivered basis, which employs economic incentives rather than contract coercion to provide incentives for SPP delivery of power.[12] This tariff structure embodies the incentives for performance in the tariff itself. When the SPP delivers capacity, it is only paid for energy. Financing of projects is available with assistance from the

[12] With 33 percent inflation of the local currency against the U.S. dollar, during the six-year program period, even with a 75 percent increase in the tariff, there has been a net 40 percent increase in the value of the energy payments in constant foreign currency equivalent. Because of the year-by-year oil price fluctuations and the resulting instability in the avoided cost, a the tariff computation introduced a three year rolling average oil price to buffer some of the swing in fuel commodity prices. The SPP projects in Sri Lanka are hydroelectric, and therefore have a significant local component of the cost of capacity development.

World Bank through local banks, but stakeholders report a financing shortfall for SPPs attributable to the limited availability of long-term financing in the local financial markets.

Table 8 sets forth in abbreviated format principal elements of the Sri Lanka SPP program, including a peak-season tariff differentiation and a rolling SPP award process.

Table 8: Primary Elements of the Sri Lanka SPP Program

1. **Process:** Open offer.
2. **Maximum size:** 10 MW.
3. **Tariff:** Avoided cost for nondispatchable projects de facto capped not to exceed tariff paid to larger IPPs.
   Differentiated for wet and dry seasons.
   Wet season: SL Rs. 5.85 per kWh [$0.06] Dry season: SL Rs. 6.06 per kWh [$0.062] (2003).
4. **Third-party retail sales:** No.
5. **Self-wheeling:** No.
6. **Energy banking:** No.
7. **Standardized PPA:** Yes.
8. **PPA term:** < 15 years.
9. **Subsidy or incentives:** SPP and IPP power equipment generally exempt from import tax and enjoy tax holiday if projects are implemented under Board of Investment rules (http://www.boi.lk).

Vietnam Program Summary

The SPP program in **Vietnam** is still in its initial phase. Therefore, Vietnam can benefit from the experience of the United States and other Asian SPP programs. Its socialist structure and the public, rather than private, companies that are candidates to develop SPP projects distinguish Vietnam. Nonetheless, the power development issues confronting Vietnam are similar to those in the other Asian nations: the need to develop additional power generation resources, the need to attract additional national and multinational capital to finance such expansion, and significant potential renewable electric generation resources that are available for development on a small scale in dispersed locations.

Three large IPP projects have been undertaken by joint ventures of state companies and private sector partners. A variety of SPP and IPP proposals are in different stages of development and seeking a PPA with the national utility. In December 2002, EVN, the national utility, committed to proceeding with SPP projects based on principles of avoided cost pricing and a standardized PPA. In this sense, it is adapting market concepts into its unique government and societal structure. The SPP program is poised to take off in an evolving formalized structure.

A year 2000 consultant-proposed standardized PPA employs a concept of "deemed" energy as a means to pay separately the capacity component of power sold. "Deemed" energy output obligates the utility to pay for the capacity component of power whether or not it takes any power. This tariff concept is typically associated with large fossil-fueled power plants; it has not yet been demonstrated in Vietnam or with renewable power projects. The PPA and its incorporated tariff structure are critical elements to graft these mechanisms onto the Vietnamese SPP development effort. This proposed multilevel tariff might not provide maximum incentives for on peak SPP performance to the state entities and peoples' committees that will be developing future SPP and IPP projects. The tariff is not structured to induce maximum production and delivery of on-peak power, because the payment for capacity value is not built into an on-peak energy component of the PPA tariff. This and other PPA issues are in the process of being discussed as EVN embarks on formal execution of SPP PPAs. The Vietnam program has the advantage of hindsight to incorporate lessons learned from the other Asian nation and international SPP experiences during the past decade as it is initiated.

Lessons Learned and Recommended Successful SPP Program Techniques

These five Asian nations utilize different forms of government and have different predominant fuel sources in their generation base (hydro, coal, gas, oil). Some of the national electric systems have an integrated high-voltage transmission system, whereas others have a disintegrated or island system. Following are the important similarities between these programs:

- All are in need of long-term increases in power generation capacity (although Thailand has a short-term current surplus).
- All have a mix of small-scale renewable energy options that could be developed.
- The installed generation base of each system is either small or disaggregated by island systems or state subsystems.
- Each country is being approached by private developers who seek to develop renewable energy SPP projects.
- Each system employs either deliberately or de facto a standardized PPA, although it is not necessarily a neutral consensual document in every case.
- Although avoided cost concepts for establishing the SPP tariff are recognized in each nation, they are not employed in all cases, or they are not employed to pay long-term avoided cost of capacity where it is provided under the PPA.

There are some interesting common elements on tariff design. Most of the programs have not elected to index their tariffs to foreign exchange (Thailand's capacity payment is an exception). In some Indian states, the tariff is indexed to inflation to retain value in international currency amid local inflation. Other countries unilaterally review and may adjust the tariff at a prescribed time. This periodic adjustment does not provide long-term predictability for project finance or equity investment. However, the adjustment period or adjustment base varies in each country. Sri Lanka, for example, employs a three-year rolling average to attempt to smooth out volatility in imported oil prices that set the marginal energy price. Other programs have implicitly capped their SPP payments below actual avoided cost so as not to exceed the power purchase rate paid to larger IPPs.

As long as local lending is employed to take out and repay at the time of acquisition of any foreign component of the SPP, indexation or hedging against foreign currency exchange is not critical. Hedging becomes important only where international commercial financing is utilized, repayment is owed to foreign equipment suppliers over time in foreign currency, or a significant imported fuel component is required. With small and renewable projects, more local financing is used, and there is no foreign fuel component. Therefore, SPP programs can avoid some of the foreign exchange challenges that confront larger fossil fuel–fired IPPs in these same nations.

Although these SPP programs are designed to equalize some of the monopsony power that the state utility can exercise in its implementation, the utilities have often been reluctant to create the level playing field that the U.S. SPP PURPA system was designed to create. The experience in several nations indicates that where the utility is the only legal buyer of SPP power, the overwhelming advantage in bargaining power enjoyed by the utility must be mitigated and balanced by a carefully designed and faithfully administered SPP program. Even where neutral rules suggested by consultants have been adopted in principle, they have sometimes been compromised in application.

Several important lessons for SPP program design and policy have been revealed by analysis of these programs, as follows.

Legal Infrastructure

- **Dispute Adjudication.** A framework for structured SPP project development is necessary. SPPs do not spring full-borne from the existing electric sector environment. There must be a system of law, regulation, and utility interface that facilitates orderly SPP development. For example, stakeholders have reported difficulty in accessing neutral court adjudications in Indonesia regarding disputes involving both renewable and conventional IPP projects. The Indonesian SPP program was never successfully implemented, and access to commercial international capital in that country has been truncated.

- **Cost-Based Principles.** Such a structured program operates best when utility operations are organized around and operate pursuant to principles of cost-covering design and collection of tariffs. When a utility is self-sustaining financially and organized as a self-sufficient body corporate, its role is not threatened by SPPs, renewable energy projects, or wholesale competition. If not organized on these sound principles, such innovations can threaten the revenue base of the utility.

- **SPP Project Enhancements.** Undercutting the value of the tariff to the SPP over time or the principles of the PPA causes SPPs to seek to sell power output to third-party buyers to realize the full market value of the power. In all programs, the first customers lost to the utility system when retail competition is introduced are those customers who have the most attractive load profiles and who are the least expensive to serve. Cream-skimming the most attractive customers by private power retailers occurs whenever competitive supply is sanctioned in any system. Those most likely to exit the system are those who pay a tariff that is above their marginal cost of supply. Therefore, if the retail tariff structure in a country is not based on reasonable cost-based and revenue-recovery principles, any form of competition, whether that be net metering, energy banking, or retail sales, will cause those loads cross-subsidizing the system to be the first to utilize and benefit from these innovations. This can further erode system revenues. The system as a whole needs to be on sound economic, financial, and legal footing to make a transition to innovative legal and transactional structures for SPP development.

- **Scale of Projects.** The eligible maximum SPP size should be scaled to system capacity so that the program applies to smaller projects that will not significantly impact system capacity. Each of the programs surveyed limits eligible PPAs to no more than 0.5 percent of installed system capacity.

- **Allocation of Risks.** A variety of commercial, sovereign, currency, and regulatory risks are implicitly or expressly allocated in the PPA. A basic risk is how the PPA allocates the risk between buyer and seller for respective nonperformance. Great diversity exists in how the six systems allocate this risk of nonperformance between seller and buyer. Some PPAs adjust the price paid for power to reflect capacity delivered, thus equalizing through price mechanisms any disparities: The Thai program reduces the SPP capacity payment where the SPP does not deliver, but has no equivalent sanction against EGAT for failure to take power. Other programs employ reciprocal legal obligations. The Indonesia and Sri Lanka PPAs, as originally designed, required both a firm SPP and the utility buyer to use best efforts to deliver and take power. However, PLN later unilaterally altered the Indonesia PPA to allow the utility to refuse to take power and not pay for this deficiency. The Andhra Pradesh PPA makes no payment for capacity value of the power, but requires the buyer to accept all power delivered. The ability of the SPP to wheel power has been made economically prohibitive. By contrast, Tamil Nadu facilitates SPP power wheeling, but the SPP is required to back down power if the utility cannot use the power. Nonetheless Tamil Nadu provides a market alternative when it does not accept power. In both Indian states, there is no firm delivery obligation on the SPP—it delivers on a nonfirm basis. In significant contrast, even though the PPA obligates neither party to sell or buy power, the Vietnam program design requires EVN to pay for "deemed energy" even when it does not accept SPP energy. The Vietnam program design shifts the risk to the utility for nonperformance.

- **Interconnection.** Utilities must interconnect with SPPs subject to a straightforward procedure to accomplish this without significant transaction costs or interconnection risk.
- **Financial Catalysts.** International funding (loans, GEF funding, Prototype Carbon Fund (PCF) payments for carbon credits) has been used as catalysts for SPP development.

Solicitation of Participation and Competition

- **Transparent Process.** A transparent process is required to build investor, developer, and lender confidence. The program in Thailand operates by declaring in advance the amount of SPP and IPP resources that are sought, and then allocating entitlements and subsidies in order of the most preferred projects and the least required subsidy for renewable projects. This is an objective and transparent program rubric. It maximizes available subsidy resources and uses the market to identify the most viable projects in need of the least government subsidies.
- **Open Offers.** An SPP program can be initiated and sustained either by an open offer to execute PPAs or by an ordered and time-limited solicitation process. Thailand and Indonesia employ the latter to control the amount and selection criteria for SPP project development. The Indian states surveyed and Sri Lanka have an open standing offer to purchase, although Sri Lanka is implementing some more thresholds and control in allowing developers to freely accept a Letter of Intent (LoI) vesting development rights at a specific site. The former countries were concerned that they might have sufficient IPP power for the short term, and thus they sought to control the quantity of additional SPP power committed. An open offer allows a constant rolling development of SPPs, much like the original PURPA design in the United States.
- **Controlled Solicitation.** An ordered solicitation can inject competitive bidding, which if correctly administered, results in bid price reduction and competition for the best projects and sites. This has been well demonstrated in the Thai experience.
- **Milestones and Bid Security.** There has been an issue in Sri Lanka and Indonesia with companies procuring LoIs or winning a solicitation, respectively, without sufficient experience or resources to actually develop an SPP project at a site. This is particularly a problem with limited hydroelectric sites (the Thai program has not developed many hydro sites). The developer's objective is to control either fixed hydro sites or SPP PPA entitlements, and in many instances planned to sell that legal entitlement, once procured, to a sufficiently capitalized and experienced third-party developer. This process does not promote the most efficient and direct SPP development, but rather layers additional transaction costs and parties into the SPP development cycle. The Thai program requires a bid security deposit of 500 baht per kW ($12 per kW) of capacity. Sri Lanka in 2003 placed a six-month limit on the validity of LoIs granted for SPP projects and required bid security bonds of SL Rs. 2,000 per kW ($20 per kW). This does not eliminate this hoarding and selling of SPP entitlements, which is particularly vexing where hydroelectric sites are involved, but it does cause a speculator to commit a forfeitable deposit and to deal quickly before the LoI terminates for lack of progress on a project.

Although bid security deposits, limits on assignment of rights, and time limits have a constructive role to play, they must be used intelligently so as not to truncate the SPP market. The Thai program also requires a deposit of 100 baht per kW ($2.50 per kW) of applicants, and more for larger sources.

- **Competitive Solicitations.** Organizing standardized SPP power capacity solicitations under a uniform set of rules provides greater program competition and uniformity of process than entertaining ad hoc applications. With a competitive process, it allows the utility to compare all SPPs simultaneously against a standard set of criteria. In such a format, the utility retains control of the option to accept SPP offers or decline such offers.

- The basic PURPA design in the United States does not provide a competitive process, although some states have grafted a competitive process onto their PURPA mechanisms.[13] An organized solicitation also allows a competitive process to drive down the bid price for SPP subsidies that may be provided, as demonstrated in the Thai SPP system. Where the system needs additional capacity, an open offer attracts the most SPPs acceptances. Where the system does not have an immediate need for capacity, a controlled solicitation of SPP bids provides the most control as a successful management practice. All the states seem to recognize these appropriate practices.

SPP Power Sale Enhancements

- **Avoided Cost Principles.** The state utility has a monopsony on the purchase of wholesale power in most of the electric sectors of nations of the world. This single-buyer model becomes a significant issue with the partial deregulation of wholesale power supply. With the encouragement of IPP and SPP supply, they are still dependent on a single state buyer to both purchase and transmit their power. Many of these programs did not introduce a mature utility regulatory authority before they introduced an SPP power program. Therefore, it is absolutely essential that the utility operate in its role as purchaser and transmission entity subject to objective PPA and tariff principles. Such tariff principles included a tariff based on avoided cost principles. To efficiently promote renewable SPPs, either (a) a program for purchase of all power at its full value to the wholesale system, or (b) the introduction of some combination of third-party retail sales, net metering–energy banking, or third-party wheeling, can be implemented to ensure SPP development. As state utility systems consider privatization, allowing retail competition can ameliorate the power of a single state utility purchaser and transmission provider. The Indian states have different policies on third-party power sales and net metering.

- **Renewable Set-Aside.** The Indonesian and Thai program models offer an interesting approach. They set aside a certain entitlement (capacity) for SPP or renewable SPP projects. This then allows the buyer to competitively evaluate the possible SPP proposals side-by-side simultaneously. This allows a simultaneous decision based on comparability of proposals. This has also been done in the United States in those states that have adopted competitive bidding programs as an innovation on their administration of the PURPA program.[14] A 21st century variant to set aside an allotment for small renewable power has been adopted in eight U.S. states that have moved to retail competition. In these eight states, a renewable energy portfolio standard requires a minimum percentage of power sold by each retail seller be derived from renewable power, as defined.[15] This forces retail suppliers, whether they are utility or competitive sellers, to obtain renewable power in the wholesale market. Tradeable "green" credits can be utilized to inject liquidity into these markets.

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[13] See Ferrey (2003), chapter 9, for a discussion of power bidding systems under PURPA in the U.S. model.
[14] See Ferrey (2003), chapter 9.

- **Third-Party Sales.** None of these five Asian programs currently allows direct third-party retail sales of power by the SPP (except in limited industrial estate areas). However, other states in India do allow direct retail sales, and each of the two states in India surveyed did allow such sales by SPPs in the past before disallowing them. Thailand, which led the initial development of Asian PPAs, is considering moving toward an open market for third-party retail sales. Therefore, experience in other places with direct retail sales, or net metering, is particularly relevant.

- **Net Metering and Energy Banking.** A recent innovation in energy banking in more than half the states in the United States is known as "net metering." Net metering provides an incentive for SPPs by allowing them to "exchange" power they produce and sell with the utility during a billing period (typically a month) with power that they or their affiliates take from the utility. This buy and sell is netted at the end of the billing period. Several of the Asian countries have adopted energy banking variants of this concept. Because the fully loaded retail price at which a utility sells power to the SPP typically is much greater than the wholesale avoided cost price at which the utility purchases power, this net metering results in the SPP being able to sell an amount of its power output at a price that exceeds the utility's avoided cost. This provides a significant subsidy of the SPP operation through the net metering or "banking" exchange.

- **Inventory of Net Metering.** Most net metering applies exclusively to renewable generation, and in more limited situations to fuel cells or cogeneration, or both. In the United States, net metering, implemented at the state level, is now regarded as the most significant incentive among several incentives to promote renewable energy and distributed generation. As part of this work, the author has prepared a separate analysis of the 36 state programs in the United States that have recently adopted net metering.

Tariff Design

- **Renewable Premiums.** In systems experiencing current and projected shortages of grid-connected power resources, temporary payment of more than avoided cost for renewable energy and small power development is one method to provide incentives for immediate power resources, and it can reflect the premium short-term value of additional power. However, there is risk in deviating from the avoided cost concept. If the utility deviates from avoided cost principles at certain times, there is nothing to prevent it from deviating at other times. This can cloud the transparency of the process.

- **Tariff Floors and Subsidies.** In many systems, additional subsidies are necessary to assist higher-cost renewable energy and smaller SPP projects. This is evident is some systems where it is difficult to fully subscribe SPP program potential. This subsidy can be accomplished by express subsidies, as in the Thai system. Alternatively, there can be a tariff structure, as in Indonesia and Sri Lanka, that supports renewable power projects by placing a floor under the energy component of renewable power sales or reflects a premium for the diversity value of renewable fuels. It is important that the buyer is reimbursed in some fashion for the premium paid for renewable power as it is introduced to meet a national policy goal.

- **Price Bidding.** Bidding can be employed strategically to minimize the ultimate system cost of renewable power resource development, as with the controlled bidding program for renewable subsidies in the Thai system. Indonesia developed a bidding program for SPP PPA entitlement, but it did not involve individually differentiated subsidies.

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[15] See Ferrey (2003), chapter 10.

- **Renewable Exemptions.** A variety of national and state tax policies (such as direct production subsidies or credits, import duty exemptions, or income tax holidays or moratoria) can target the development of renewable SPPs and reduce effective higher construction costs. However, such subsidies typically apply to equipment for both SPPs and IPPs.
- **Tariff Incentives.** It is a successful practice to provide market incentives through the PPA structure. A PPA where the incentive for SPP operational compliance is embedded in the energy (kWh) payment, rather than split into a fixed capacity payment plus an energy payment, maximizes the economic incentive for the SPP to deliver power at peak times. This is because when power is not supplied, 100 percent of the potential revenue stream—embodying both energy and capacity if a capacity payment is included—is lost to the SPP. The alternative is to include legal sanctions in the PPA for nondelivery or other failure to perform. This would involve complicated decisions on the reason for failure to deliver, and ultimately recourse to a reliable, prompt, and neutral arbitration process or court resolution. In many of these countries with smaller renewable power programs, it is more transparent and straightforward to embody these incentives in the tariff operation, rather than embed legal sanctions in the PPA. Properly structured incentives can work more efficiently than penalties. That proper structure is a specialized exercise.
- **Capacity Tariffs.** The SPP PPA tariffs in the Indonesian, Thai, and Sri Lankan programs were designed to include capacity payments in the tariff payment for each kWh-delivered, paid only if the SPP delivers power. This was designed to provide the maximum incentive to the SPP for dedicated performance and delivery of power, while not invoking any coercive penalties against the SPP for failure to perform to a set standard. This type of simplified incentive is appropriate for renewable SPPs, where the marginal cost of operation is relatively low compared to the initial capital investment. During implementation in setting these tariff levels, Sri Lanka altered the tariff design to eliminate the capacity component for both short- and long-term contracts.
- **Standardized PPA.** All programs employ standardized PPAs, and most employ either an avoided cost-based tariff or avoided cost principles with a cap on the tariff. All allow some form of long-term firm contract commitment.

Asian SPP programs designed to foster renewable energy development suggest a range of successful practices for PPA development in these contexts. Table 9 highlights some of those successful practices, which have been implemented in five programs in Asia.

Table 9: PPA Successful Management Design and Practices

Successful design and management practice features	*Thailand*	*Indonesia*	*Sri Lanka*	*India: Andhra Pradesh*	*India: Tamil Nadu*
PPA size <0.5% of system capacity	Yes	Yes	Yes	Yes	Yes
Open offer if need capacity	n.a.	No, but very large solicitation	Yes	Yes	Yes
Controlled solicitation if surplus	Yes	n.a.	n.a.	n.a.	n.a.

Successful design and management practice features	*Thailand*	*Indonesia*	*Sri Lanka*	*India: Andhra Pradesh*	*India: Tamil Nadu*
capacity					
Milestones on development time afforded SPP	n.a.	Yes	Yes	Yes, if NEDCAP financial guarantees	n.a.
Bid security deposit by SPP	$12 per kW	n.a.	$20 per kW	n.a.	n.a.
How renewable technologies are encouraged	Competitive award of subsidy	Hierarchy of renewable SPP preference; floor price on renewable power	Floor price on renewable power	Tariff differentiated for base load and intermittent renewable SPPs	None
Competitive solicitation	Yes	Yes	No	No	No
Standardized PPA	Yes	Yes	Yes	Yes	No, under development
Long-term firm PPAs	Yes	Yes	Yes	Yes	Yes
Avoided cost based tariff	Yes	Yes	Yes	Yes	Yes
Capacity payment for long-term power	Yes	Yes	No	No	No
Allocation of performance risk between seller and buyer	Alteration of capacity payment; utility can refuse delivery	Neutral; originally mutual best efforts	Neutral; mutual best efforts	Nonfirm, but utility must accept all power	Nonfirm, but utility can refuse delivery
Capacity payment adjustment if seller does not deliver power	Yes	No, capacity payments in peak rate	n.a.	n.a.	n.a.
SPP unit dispatchable	Yes, if firm capacity PPA; 80% minimum annual output purchase obligation	No, as PPA originally conceived; dispatchabl e without limitations after PPA changed	No	No	No
Wheeling, net metering, or energy banking	Energy banking	Wheeling	n.a.	Energy banking,	Energy banking,

Successful design and management practice features	*Thailand*	*Indonesia*	*Sri Lanka*	*India: Andhra Pradesh*	*India: Tamil Nadu*
				wheeling	wheeling

n.a. Not applicable.

2. ANALYSIS OF FINANCING CONSIDERATIONS

Numerous countries have attempted to attract and implement renewable small power project development. These projects seek to attract private sector capital to augment power development in the nation. In many developing nations, there is a need for private capital to finance electric infrastructure development. To successfully attract significant private capital in any quantity into the electricity sector, several elements must be present:

- There must be a system of government regulation for the siting and permitting of power facilities that is explicit, substantive, and procedurally accessible. A single permit administered by one ministry is preferable to attract investment.
- The rights of private independent power developers must be established and vested by contract. The contract must vest rights to develop, build, and operate a power-generating facility, with a guaranteed long-term contractual sale through interconnection to a stable ultimate purchaser of the power. The payments by that purchaser must be secure for the life of the power sale contract. This may require government guarantee of the utility obligation, opportunities for third-party direct retail sales or export of power, or special credits for renewable power development. In the five Asian nations examined, one of the primary concerns of stakeholders was that some utilities had not paid full avoided cost (Sri Lanka and Indonesia). Experience in Indonesia and India also demonstrated that IPP contract prices would not necessarily be respected when currency devaluations altered the expected cost of the power in equivalent local currency.
- The price of power purchased must be contractually established for the duration of the term of the contract, with appropriate adjustment clauses (escalators) to account for changes in the costs of operation, attributable to changes in fuel costs, operation and maintenance, taxes, changes in law or regulation, and so forth. The price component must sufficiently cover debt repayment for the life of the project debt, under all scenarios possible under the key contracts, as well as providing a sufficient residual to compensate the equity investment and risk. A primary stakeholder concern in the Asian countries surveyed was the security and adequacy of the tariff price protection over time. If provided securely in the PPA, this provides credit support for long-term financing of the SPP project. Not all these countries provided that, although all these countries have a policy of adjusting the tariff periodically to reflect changes in avoided energy costs. However, since the tariff level year-to-year is not contractually guaranteed or locked into an objective formula in most of these programs, it does not provide bankable credit support for project financing.
- For the private developer fuel supply and transportation, equipment acquisition, construction, and operation and management must all be established securely by contract, within the context of applicable laws and regulations. These contracts must offer sufficient credit support and guarantees to ensure project viability and timely completion at fixed costs. A significant stakeholder concern in each of the five Asian countries examined is the practice of the ministry and utility to alter the contract price or the contract tariff escalation factor in contravention of original program design or contract requirements. Indonesia and some Indian states have balked at enforcing contract provisions in IPP contracts.
- A lender's right of notice of deficiencies and right to cure breaches or defaults in the duties and obligations owed by the independent power facility must be in the power sale contract, to prevent loss of the long-term benefits of power sale. This is necessary in any project financed by international capital. For smaller renewable energy projects financed by local equity and debt capital, these requirements may not be as exigent. Some of the PPAs provide this; most others do not.

- There needs to be recourse to a system of law that provides speedy and impartial resolution of disputes that cannot be mutually resolved. In most instances, this requires recourse to a proved, swift, and procedurally guaranteed right to recourse in a court in a stable country with a neutral independent judiciary honoring the rights of timely appeal, as well as the ability to enforce a judgment in the host country. Experiences in some developing countries have proved that expectations of such neutral judicial recourse have not in fact been available. By contrast, choice of forum for dispute resolution and choice of law to apply can be elected. Larger IPP contracts may designate international tribunals or choice of law to remove adjudications from the bias of a host country or to seek a more neutral forum. Some developing nations have not respected such choices or have refused to enforce judgments rendered by courts or international tribunals.

- To attract international capital, the contract must contain a mechanism to adjust for fluctuation in foreign exchange ratios, so that project cash flow is held constant in the converted currency (or currencies) in which the international investments in capital equipment are denominated, or of an agreed internationally acceptable currency. There also must be sufficient availability of these foreign exchange currencies. Many of the smaller renewable power projects surveyed here are not dependent on a substantial foreign exchange–denominated component or foreign lending, as are larger IPP projects. Most of the SPP programs do not adjust for foreign exchange, on the theory that borrowing will be local. The Indonesian SPP program did attempt to adjust capacity payments for changes in the cost of capacity, with a substantial off-shore capital component.

Some of the SPP programs in developing countries were initiated in response to funding opportunities from the World Bank or other multilateral funding authorities. These targeted efforts have provided technical assistance to the host countries for the development of a structure for the SPP program, analysis of tariff issues, assessment of local lending opportunities, and development of a standardized PPA and standardized tariff structure for SPP implementation. If not developed in a standardized, impartial and neutral manner, these issues can be extremely contentious between various stakeholders, and the program can fail.

The tariff establishes the economic framework for the long-term power transaction. Tariffs also may need to change over time to reflect the fluctuating marginal cost of power production for the utility. Although the determination of a proper tariff is a complex and sophisticated undertaking that typically requires analysis by experts, its impact is straightforward for an individual prospective SPP. At the tariff provided by contract, the transaction either does or does not work financially. A pro forma analysis determines whether or not the tariff is sufficient to motivate SPP development.

The PPA is a more nuanced consideration. This contract is the legal basis for financing a greenfield SPP. It is the skin of the operating relationship of the parties lasting decades. As a binding legal relationship, it is essential that the contract anticipates a variety of construction and operating contingencies, and establishes operating parameters that govern the sale of an invisible, unstorable electric commodity moving at the speed of light. The importance of a standardized PPA, properly designed, is that it provides a fair, neutral, and financeable contractual arrangement between the power seller and purchaser. The PPA embodies the core legal relationship for subsequent third-party contracts and credit relationships with lenders, equity participants, and equipment suppliers. With independent private power development, the contract becomes the sole legal vehicle for the transaction in electric power.

Ultimately, the PPA must meet the norms required for debt finance of the project and the attraction of equity interest and capital. Because of this requirement, the PPA must contain certain legal provisions to provide security for these lenders and investors. These lenders look at the project economics, the project prospect for successful permitting, and the PPA as the legal embodiment of ultimate lender protections. What has evolved in SPP project finance is the expectation of a PPA that satisfies a set of basic requirements. This translates to a conventional PPA format that has evolved from the PURPA experience in the United States to many international locales.[16] If it does not contain these elements, the project becomes unfinanceable and typically fails.

This report has analyzed the SPP project experience and SPP structure in five nations in Asia at different stages of SPP development. The relatively mature programs in Thailand and in two states of India are analyzed. The significant program experience in Sri Lanka and Indonesia are evaluated, as well as the more recent initiatives in Vietnam. These countries vary greatly in size—whether they are an island-based system or an integrated national grid—as well as in the dominant fuel used in power generation and the availability of renewable resources for smaller-scale power production. Thus, the analysis that follows provides a reasonable cross-section of experience in developing nations in Asia. From these comparisons come important lessons and policy implications.

[16] To a lesser degree, some contracts are based on a U.K. model of financing. If the PPA is not in an official English language version, this impedes international and, in some cases, local project finance.

3. THAILAND

Program Overview

Thailand was one of the first countries in Asia to adopt a small power solicitation program. The Electricity Generation Authority of Thailand (EGAT) currently has installed about 22,000 MW of generation capacity, making it the largest electric system surveyed here (where Indian states are looked at as separate utility systems). Peak demand is at 16,500 MW during seasonal peak (April). At this current level, Thailand is presently in a surplus situation, also making it the only system reviewed that is in surplus. Some of this surplus is the result of a successful IPP-SPP program. Power demand is expected to grow at about 4.6 percent annually.[17] EGAT is scheduled eventually to restructure to a competitive retail model operating through a power pool.[18]

The Thai program was modeled on elements of the PURPA small power program in the United States. The roots of most of the Asian small power programs are either the U.S. PURPA program, or other Asian country SPP programs that were modeled on the PURPA program. Competitive bidding was introduced in the late 1980s by Maine, Massachusetts, and subsequently several other states in the United States.[19]

The monopoly state utility, EGAT, is the only entity to which an SPP may sell power in Thailand. No direct retail sales are now allowed. However, such concepts are now under discussion within the regulatory authority to allow net metering or direct retail sales by SPPs, or both, at a future time.

What is of particular note in the Thai system is that competitive bidding by renewable energy SPPs is used to suppress and award subsidy payments. No other of the five national systems reviewed here employ such a feature. It has been successful in minimizing the cost of such subsidies and employing available subsidy funds to bring forth the maximum number of megawatts of new private power resources.

However, such a competitive system requires that there be a controlled competitive solicitation process for SPPs. Thailand and Indonesia operate such a solicitation. By contrast, India's two states analyzed herein and Sri Lanka avoid a solicitation in favor of a continually open offer to sign PPAs and purchase power. Both systems have advantages, but only with a competitive solicitation can competitive bidding for subsidy be applied.

Program Design and Implementation

The following sections analyze in detail each of the key elements of the Thai program.

1. Solicitation of SPP Participation and Program Mechanism

EGAT periodically announces the solicitation of additional SPP resources. This allows a competitive bidding process to award limited subsidies to projects. A first request of 300 MW was made for SPP power by EGAT in 1992. This amount was expanded to 1,444 MW in late 1995. EGAT in 1996 announced additional purchases from renewable SPPs. A formal solicitation was recommenced in fall

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[17] Pichalai (2002), p. 27. The surplus generating capacity is expected to be absorbed by 2006 demand levels. Pichalai (2002), p. 29.
[18] Pichalai (2002), p. 35. There will be system operator and divestiture and privatization of assets, overseen by a new regulatory agency, NERC, much like the U.S. FERC.
[19] See Ferrey (2003), chapter 9, for a discussion of all bidding schemes deployed under PURPA.

2001, for eventual award of contracts by the end of 2002 or early 2003, but this was suspended because of the power surplus situation. As of this date, no additional IPP power is being accepted, but small SPP power is still accepted.

2. Size and Resource Limitations

Eligible projects include biomass, waste, minihydro projects, photovoltaic (PV) systems, or other renewable projects, such as wind. Conventional fossil fuels can be used for up to 25 percent of the fuel of such a resource on an annual basis. The eligible cogeneration technologies must use energy sequentially in a topping or a bottoming cycle. At least 10 percent of the energy output annually must be utilized in a thermal application. System efficiency of 45 percent must be achieved for the use of oil or natural gas in a cogeneration system. Each of these above requirements mirrors the PURPA requirements in the United States in fundamental ways.

The regulations allow SPPs to deliver for sale to EGAT up to 60 MW, although up to 90 MW is within the discretion of EGAT to accept on a case-by-case basis. The project can have a nameplate capacity greater than the limit, as long as power sale is limited to the allowed capacity. Several projects at 90 MW have been accepted. EGAT does not contract with projects below 1 MW; these very small projects sell power output directly to one of the two national distribution companies.

3. Power Authority Role

The power authority is the sole buyer of power. The government executes the PPA and provides subsidies. The subsidies are provided competitively through a bidding process. This is an innovative feature of the Thai system. Subsidies are available in the 2001–02 solicitation process for up to five years for renewable projects in the amount of not more than 0.36 baht per kWh ($0.01 per kWh.). The subsidies are granted under the Energy Conservation Promotion Fund Committee (ENCON), established by the Energy Conservation Promotion Act, B.E. 2535 (1992). Two billion baht ($50 million) is allocated to such renewable project subsidies, in up to 300 MW of such projects contracted after June 2000. Selected projects must be in commercial operation by September 2004 or earlier.

The regulatory authority, the Energy Policy Office (EPO), has used competitive bidding as the tool to select the applicants with the lowest required subsidy-adder to receive the subsidy. Additional money is allocated to other conservation and complementary programs. The application procedure for obtaining such subsidies is extremely sophisticated, documenting a host of financial factors, expenses, and revenues. The average subsidy awarded has been 25 baht per kWh ($0.006 per kWh) to 31 projects for 513 MW.

SPPs and IPPs benefit from an eight-year tax holiday on tax applicable to net profits from project operations. There is no tax in Thailand on the sale of power output to EGAT.

4. Number and Capacity of SPP Interest and Applications

EGAT has received 110 proposals.[20] Among these are 82 firm power applications for 2,800 MW, of which 50 projects for about 2,000 MW successfully received a PPA since 1992 when the program began. Some projects withdrew, which left about 35 firm contract projects, as well as some nonfirm projects. A project is deemed nonfirm if (a) it receives a contract of less than five years, or (b) it is an

[20] Pichalai (2002), p. 6. Thailand also purchases power from Laos and in the future from China under long-term agreement. Pichalai (2002), pp. 16ff.

intermittent technology without capacity value. About half of firm applications have been accepted, whereas about 70 percent of nonfirm applications have been accepted. Of note, most of the Thai SPP projects are not renewable projects, but are gas-fired. Although the program is a success and has demonstrated SPP cogeneration potential, it has not restricted participation to renewable sources. Similarly, the Indonesian program (discussed later) promoted SPPs with a preference for, but not a restriction to, renewables as compared to cogeneration.

5. Criteria for Award

An objective and transparent scoring and evaluation process is utilized, reflecting the factors itemized below. In this regard, it mirrors some of the most sophisticated second generation state PURPA bidding processes in the United States.[21] The Thai program operates through a formal solicitation process. A technical submission is made in Thai language,. The technical submission provides information about:

- Power plant size and capacity net of on-site use.
- Renewable energy production process and fuel use.
- Site location.
- On-site power usage.
- Feasibility studies.
- Construction permits and other necessary consents.
- Work plan, schedule, and project timetable.
- Developer's experience.
- A declaration that the information provided is true and complete.

6. Award Data

As of July 2001, the program had attracted, accepted, and obligated 44 energy projects for 1,799.9 MW, of which 156.9 MW were powered by renewables. An additional 300 MW of renewable power was being sought by EGAT.

As of the end of 2002, 71 SPPs had been accepted and obligated, with a total capacity of 2,330 MW. Thirty-five of these SPPs for 2,048 MW were firm commitments, whereas 36 projects for 282 MW were shorter-term nonfirm commitments.[22] Of these 71, 23 nonfirm and 27 firm contract SPPs had entered commercial operation; the remainder were still in development. Five had not yet signed a contract. Ten of the 35 firm contracts employed exclusively renewable energy (all biomass) or cofired biomass. Thirty-four of the 36 smaller nonfirm projects employed renewable resources.

From these data, it is apparent that the larger IPP projects tended to utilize principally conventional fossil fuels, mostly natural gas, but including coal and oil, and tended to have firm PPAs. The bulk of the

[21] For information on PURPA bidding schemes, see Ferrey (2003), volume I, chapter 9.

[22] From EGAT (2002). The nameplate capacity of the 35 firm projects was 3,620 MW, of which 2,048 MW was committed to EGAT at no more than 90 MW per project. The nameplate capacity of the 36 nonfirm projects was 823 MW, of which 282 was committed to EGAT, with the largest being 45 MW from one of the few nonfirm, nonrenewable energy projects.

renewable fuel SPPs had a smaller installed and dedicated capacity, and had nonfirm contracts. In this sense, the renewable energy projects were disadvantaged.

7. Size and Type of Technologies

SPPs of up to 90 MW can sell power to EGAT on a case-by-case basis, although 60 MW is the specified maximum size in the regulations to which each SPP is entitled.

The bulk of these projects are cogeneration projects, and most of these firm power projects are powered by natural gas. It is also typical of these renewable SPP projects that they are cogenerating power for self-use and exporting less than the installed capacity. Many of those above have an installed capacity above 90 MW and contracted to sell EGAT 90 MW. Contract terms of 20–25 years are the norm for these larger cogeneration projects under firm contracts.

The renewable energy projects are primarily comprised of rice husks (some times augmented by wood chips) and bagasse (sugar mill waste). Also represented are projects fired by wood waste and solid waste. Many of the renewable SPPs are much smaller—1–8 MW—and do not have long-term contracts, or they have nonfirm contracts that are extendable by EGAT. A few of the renewable SPPs have set 5- or 10-year contracts.

8. Completion Ratio and Reasons for Failure

There has been a relatively high completion ratio.

9. Process Transparency

The process appears to be very transparent. Scoring is done on project applications.

10. Stakeholder Concerns

Stakeholders are concerned about the standardized PPA, which was solely drafted by EGAT. The PPA was criticized as being too simplistic and not protective of SPP interests. Many SPP and IPP projects borrowed foreign debt capital in U.S. dollars because it carried a lower interest rate and longer term than local loans. However, some sophisticated international lenders refused to lend because the PPA for SPPs was too simple and not adequate:

- ❖ In particular, the commitment to purchase was too indefinite. The PPA has become even more critical in the current lending environment, where loan terms have fallen to 9–10 years maximum from 12 or more years before the 1997 financial crisis.
- ❖ The financial crisis in 1997 caused a dilemma for some projects that had borrowed in foreign currency (U.S. dollars), but were receiving PPA payments in Thai baht. A fundamental restructuring was required, where foreign exchange indexation of capacity payments and adjustment of fuel prices was required.
- ❖ Concern was also raised about EGAT dispatch protocol for SPPs. Greater coordination between EGAT and the two national distribution companies was recommended. The tariff level was not criticized by developers. Third-party retail sales are allowed within an industrial area, or if the government grants a concession.

- ❖ Energy banking or net metering was suggested to be helpful in those situations where EGAT, now in surplus, was not accepting all power output. Energy banking could allow these projects to operate at higher level.

11. Lessons

The Thai experience underscores several important lessons:

- ❖ Where foreign capital is involved, indexation of capital payment to foreign currency exchange maybe required.
- ❖ A controlled solicitation for SPP power can utilize competitive bidding to allocate subsidies for renewable power SPPs in a manner that suppresses the cost of those subsidies to the government and maximizes the amount of power brought forth by the amount of subsidies available.
- ❖ Where a surplus power situation occurs, an IPP program can be suspended, but because renewable energy SPPs utilize "free" fuel flows, an SPP program should be continued.
- ❖ Tax holidays are a significant stimulus to SPP development.

Power Purchase Agreements

The principal features of the Thai agreement are given in table 10.

Table 10: Features of Thai SPP PPAs

Feature	*Description of SPP feature*
Basic provisions	
1. Parties	Contracts are made between the SPP and the power purchaser, typically EGAT. Projects of less than 1 MW contract directly with one of two national distribution companies.
2. Milestones	The PPA contains no milestones.
3. Delivery of power	By regulation, power is delivered at the metering point.
4. Output guarantees	Where their duration is five years or less, the contracts are nonfirm without a capacity payment or a firm commitment to deliver power. For a capacity component payment, by regulation, the SPP must make a capacity commitment of at least five years. The capacity obligation requires the SPP to supply electricity during the peak months of March–June and September–October and must supply no fewer than 7,008 hours annually of power, per the regulations, if the power source is wind, solar, or minihydro. The regulations require for waste, biomass, and tree plantations, that annual hours must be at least 4,672 annually and include March–June. By regulation, the monthly capacity factor must not be less than 0.51. Output guarantees are in the form of limits on the time for planned maintenance and in the posting of security for contract performance. A bid bond of 100 baht per kW ($2.50 per kW) is required of applicants. The security for a bid was 500 baht per kW for some contracts. A performance bond in the amount of 5% of the total receivable capacity payment discounted to present value is required to be posted by selected applicants for the term of the contract. A Letter of Credit is a permissible means to satisfy this requirement. By regulation, all shutdowns for maintenance shall be accomplished during the off-peak months of January, February, July, August, November, and December. Maintenance shut-downs are limited by regulation to 35 days per year.

Feature	*Description of SPP feature*
5. Engineering warranties	By regulation, the SPP must generate electricity in accord with the EGAT Regulations for the Synchronization of Generators to the System. The SPP is responsible legally for any damage to the EGAT system.
Sale elements	
1. Power quantity commitment	Up to 90 MW is some instances, and up to 60 MW in size typically. EGAT recently has been accepting 100% of power output on peak, but only 65% of capacity off-peak, for a weighted average of about 80% of capacity.
2. Metering	Provisions for meter accuracy address the determination of the quantity of power sold, and procedures for redress. The meters are owned by the SPP. Accuracy is required within 2–3%. Meter accuracy in U.S. small power purchase contracts typically is required to be within a range of 0.5%–2.0% of precise accuracy. Metering occurs at the delivery point specified by EGAT. If the SPP's meters are capable of measuring power supplied during peak, off-peak, and partial-peak periods, it receives, by regulation, time-differentiated energy payments. If not, an average energy rate is applied to all power delivered.
3. Net metering or exchange	Not presently allowed. EGAT is taking only 65% of power output capacity during off-peak periods because it is in a temporary surplus situation. Small renewable SPPs below 1 MW contract directly with one of the two national distribution companies rather than EGAT, and for these projects net metering is permitted. No self-wheeling is permitted.
Risk allocation	
1. Sovereign risk and financial assurance	The laws of Thailand govern the interpretation of the contract. There is no sovereign guarantee. In some contracts, the SPP is required to post a bank guarantee against premature termination of the agreement.
2. Currency risk	The financial crisis in 1997 caused a dilemma for some projects who had borrowed in a foreign currency ($), but were receiving PPA payments in Thai baht. A fundamental restructuring was required, where foreign exchange indexation of capacity payments and adjustment of fuel prices was required. The capacity payments are now adjusted for exchange rate fluctuations in the baht–U.S. dollar exchange, by a formula specified in regulation and geared to changes in the price of the fuel used. Traditionally, the energy payments are adjusted automatically for changes in the baht–U.S. dollar exchange rate, depending on the type of fuel used in the facility. This exchange was linked to changes in the price of Thai gas, Thai oil, or Japanese coal. However, as of 2001, the energy payment is adjusted, but no longer indexed. As of 2001 and thereafter, the energy payment for a firm contract was 1.49 baht per kWh ($0.034 per kWh), adjusted for changes in the price of Thai gas and not indexed to any foreign currency. In 2001 for an energy-only contract, which by definition is for a duration of five years or less, the energy payment was 1.59 baht per kWh ($0.036 per kWh), adjusted for changes in the price of Thai gas, without indexation to a foreign currency.
3. Commercial risk	Risk is allocated implicitly to SPP. EGAT needs to take only 65% of rated capacity during off-peak periods and only 80% or more of annual SPP capacity (assuming 100% of peak-period power is taken).
4. Regulatory risk and change of law	If there is a change of law, at the request of the aggrieved party, the parties agree to meet to attempt to resolve the issue. If no resolution is reached, the contract remains in force, and the matter is not considered to constitute a dispute for arbitration.
5. Excuse and force majeure	Force majeure is defined to include acts of government, including seizure of the power plant, and includes otherwise fairly standard provisions of accepted international contract format.

Feature	*Description of SPP feature*
Transmission	
1. Transmission and distribution obligations	The sale transaction occurs at the meter. Transmission on the down side of the meters is the responsibility of EGAT.
2. Interconnection arrangements	By regulation, interconnection costs are the responsibility of the SPP prior to supplying electricity.
Tariff issues	
1. Type of tariff	EGAT incorporates an avoided cost tariff concept. Energy payments are determined from EGAT's long-term avoided energy cost for any contract with a capacity commitment, defined as five years or more. For shorter contracts, which are not eligible for capacity payments, the energy payment is determined from EGAT's short-term avoided energy cost, by regulation. These calculations approximate the fuel cost plus the O&M cost of the power plant avoided or not run during peak, off-peak, and partial-peak periods. In the 1996-vintage contracts, the energy payment was calculated as 0.87 baht per kWh ($0.035 per kWh at then exchange rates) for energy-only contracts, and somewhat less for energy in longer-term contracts, which added capacity payments of 204–285 baht per kW per month for contracts of 10–15 years (the longer the contract term, the higher the capacity payment). In 2001, the capacity payment for contracts of 10–15 years was 270 baht per kW per month. For a 20-year agreement, the capacity payment was 400 baht per kW per month. For 5–10 years, it was 217 baht per kW per month.[23] As of 2001, the energy payment for a firm contract was 1.49 baht per kWh, adjusted for changes in the price of Thai gas, not indexed to any foreign currency.[24] To translate this to a representative tariff, if one assumes an 85% capacity factor for the SPP, under 2003 exchange rates, a firm PPA for a 20-year term receives a total payment (energy and capacity) of Rp.2.14 baht per kWh [$0.051 per kWh]. In 2003 for an energy-only contract, which by definition is for a duration of five years or less, the energy payment was 1.59 baht per kWh [$0.037 per kWh], adjusted for changes in the price of Thai gas, without indexation to a foreign currency.[25] Therefore, there has been a change in the formulas for capacity and energy payments, with a simplification in the current iteration. Traditionally, the energy payments are adjusted for changes in the baht per U.S. dollar exchange rate, depending on the type of fuel used in the facility. This exchange is linked to changes in the price of Thai gas, Thai oil, or Japanese coal. However, as of 2001, the energy payment is adjusted, but no longer automatically indexed.
2. Capacity obligations	**Duration:** By regulation, capacity payments are determined from EGAT's long-term avoided capacity cost for firm contracts and capacity commitments, which must be 5–25 years. The capacity payments are adjusted for exchange rate fluctuations in the baht per U.S. dollar exchange, by a formula specified in regulation, relevant to changes in the price of the fuel used. In return for capacity payments, SPPs must submit to being dispatched within the minimum 80% annual take obligation of the buyer. **Seasonal and Hourly Requirements.** The SPP must supply electricity during the peak months of March–June and September–October, although no minimum seasonal

[23] EGAT (2001).
[24] EGAT (2001).
[25] EGAT (2001).

Feature	Description of SPP feature
	capacity is specified. This eliminates certain agricultural biomass units that are not available during the peak demand seasons. In addition, to receive capacity payments, the SPP must supply no fewer than 7,008 hours of power annually (although there is no specified minimum amount of capacity during these hours) for wind, solar, fossil-fired, and minihydro, but for waste, biomass, and tree plantations, those annual hours of generation must be at least 4,672 and need only include operation during the March–June seasonal peak. The intermittent renewable resources have a more exacting hourly minimum than the base loadable renewable resources, and thus would likely not be able to qualify for capacity payments. By regulation, the monthly capacity factor must not be less than 0.51 for any project receiving a full capacity payment in a given month. Capacity payments are reduced by half if the monthly capacity factor is less than 0.51. The power factor must be between 0.85 leading and lagging, by regulation. Under the regulation, delivery of whatever amount of kW produced by a renewable resource during the seasonal peak months, and SPP availability for and delivery of some power during the minimum required hours, would satisfy these regulatory requirements. Nonetheless, most intermittent (solar, wind, run-of-river minihydro) renewable SPP projects will not qualify for capacity payments. Some base-loaded SPPs could qualify for capacity payments by operating 60% of the year including during four peak months.
3. Fuel price hedging	This is not a part of the PPA.
4. Update mechanism	The avoided fuel price of EGAT, as it changes up or down, is flowed through in periodic energy payments to the SPP, by regulation.
5. Tariff penalties for nonperformance	If the SPP is unable to supply electricity in excess of the monthly capacity factor of 0.51, the capacity payment for that month is reduced to 50% of the specified capacity payment, by regulation. Similarly, if EGAT is not able to take electricity for a period of time, those hours are subtracted from the hours used to calculate the capacity factor for purposes of capacity payments. A contract can require the SPP to supply power at stated levels in the case of EGAT need. If the SPP does not so provide such commitment when asked, for each such day 4% of the monthly capacity payment shall be withheld, by regulation. At year-end, if the SPP has not satisfied the number of hours required to supply under regulation, EGAT may recall the capacity payments already made at a rate of 0.0625% per hour for each hour of deficiency.
Performance obligations	
1. Operational obligations	To the extent that the above capacity performance requirements are not satisfied by the SPP, the SPP is given 18 months to rectify the performance deficiency. If performance is not rectified, the capacity contracted for by EGAT can be unilaterally reduced to reflect actual performance, under regulation. After the midpoint of the contract term, the SPP shall have the election to reduce its contract-committed capacity with advance notice to EGAT. The SPP must be willing to commit to reduce its supply during off-peak periods (21:30–08:00 hours) to 65% of its contracted capacity upon request of EGAT. By regulation, EGAT must take 80% of annual available power. Any amount not purchased during one year is carried forward as a purchase commitment during the subsequent year, by regulation.
2. Definitions of breach	Breach is defined in a conventional manner. The defaulting party has 15 or 90 days to remedy the default, depending on its nature. In some contracts, the SPP is required to post a bank guarantee against premature termination of the agreement.
3. Termination opportunities	If the SPP terminates, the capacity payment is rectified with the actual term of the contract with interest. SPPs eligible for capacity payments must deposit security payments in the amount of 10% of the capacity payments expected during the first five

Feature	*Description of SPP feature*
	years. This deposit is refunded at the completion or termination of the contract on terms that allow termination by the SPP.
4. Guarantees of payment and performance	There are no outside guarantees of payment. However, late payment carries interest at 2% above the overdraft rate of the Krung Thai Bank Public Company.
5. Assignment or delegation	Assignment is not allowed without permission of the other party, except to subsidiaries or for the purpose of financing. These are standard provisions.
6. Dispute resolution	By regulation, arbitration is allowed to resolve disputes, with appeal to Thai courts. In the contract, arbitration is specified. Two arbitrators, one selected by each party, attempt to arbitrate disputes. They can select an umpire if they cannot agree. The arbitration proceeds under the Thai Ministry of Justice Rules in Bangkok in the Thai language. The parties may substitute by mutual agreement the Rules of the International Chamber of Commerce. A party has a right to redress in the civil courts.

4. Indonesia

Program Overview

Indonesia in the mid-1990s was undergoing significant power sector growth. The generating resources of PLN, the state utility, were not sufficient to keep pace with the demand growth. Approximately one-third of the installed generating capacity in Indonesia was on-site privately owned self-generation. Because of the extensive agricultural, oil and gas, mining, timber, and manufacturing interests in the nation, there was substantial possibility for renewable energy development and cogeneration. Moreover, there was a significant opportunity to entice installed "captive" generation to contract for sale to the national grid.

The government subministry, the Directory General of Electricity and Energy Development (DGEED), PLN, and with support from the World Bank, began to devise an SPP program in 1993. International consultants were hired to draft a standardized SPP PPA and tariffs for an SPP program. This was undertaken as part of a rural electrification project loan from the International Bank for Reconstruction and Development (IBRD or World Bank). Several draft contracts and tariffs were prepared, and the final version of each became a covenant in the loan agreement between the Government of Indonesia and the World Bank.

Program Design and Implementation

1. Solicitation of SPP Participation Mechanism

Based on consultant reports and a standardized tariff and PPA, the SPP program was set up to begin in calendar year 1996. The program was to offer a PPA in either an official English language version or an official Indonesian language version, at the election of the PPA and its lenders. The PPA would be standardized and not subject to negotiation. The tariff would be standardized by each region (*wilayah*) of the major island grids and isolated diesel grids. Negotiation would not be allowed on material contract or tariff issues. Choices on interconnection and commencement date would be left to the SPP. The program was announced publicly. Applications were due at a uniform time from all bidders, although in practice, this was not uniformly honored in each region, as described below.

Renewable resources were afforded a preference in the solicitation. There were four descending tiers of project priority, with renewable energy at the top, cogeneration with renewable and then fossil-fired cogeneration in the middle tiers, and conventional noncogeneration fossil fuels at the lowest tier. In operational terms, each region would award completed applications first from the top-tier renewable resources, proceeding down the hierarchy until the resources solicitation block was filled with available resources. Therefore, this "stacking" in program design accomplished a clever dynamic. It fills up the queue first with renewable resources, and then proceeds to accept additional small power resources, so that the overall SPP objectives are given full consideration.

What is important to stress is that the Indonesia program does not accept renewable projects that are less qualified than cogeneration projects. Rather, if applications are equal and both are willing to accept the avoided cost price, the program first accepts the offer of the renewable SPP. They are taken first until the allotment is filled. This makes sense, given that scarce fossil fuel resources are thus preserved unless needed.

The agreement made by the Government of Indonesia was to procure as much as one-third of future power resources under this program. Therefore, had it been implemented, renewable resources and small power resources would have an opportunity to compete for a meaningful share of what was then a 10 percent plus per year power demand increase in the nation. In program design, this was ambitious. Simultaneously, though, Indonesian ministry officials were signing contracts for large nonrenewable IPP projects on an ad hoc basis. The oversubscription of large IPPs posed an inherent conflict to the agreed SPP program, especially once the Asian financial crisis occurred in 1997 and thereafter as the SPP program was rolling out.

2. Size and Resource Limitations

The SPP solicitation was differentiated for eight different island grids in Indonesia, and for isolated systems not connected to the transmission grid. On the islands of Java-Bali, which integrated grid serves 75 percent of the country's population, projects up to 30 MW were eligible. On other island grids, projects up to 15 MW were eligible to submit a project application.

3. Power Authority Role

Under the officially approved program, the utility agrees to solicit and purchase 10 percent of the projected peak plus reserve margin on each major grid outside Java-Bali for the next eight years. On Java-Bali, the obligation is 5 percent of peak.

The DGEED oversaw the implementation of this project by the utility, PLN. PLN organized the solicitation and trained its regional offices to administer it. This decentralization resulted in significant variation in implementation in the regions.

Indonesia has a complex set of ordinances, official acts, presidential decrees, regulations, and directives that affect the provision of electricity in the country.[26] Four of these are particularly relevant to the provision of electric power by independent producers:

*Law No. 15 of 1985
*Regulation No. 10 of 1989

[26] Sequentially the laws, acts, regulations, and directives affecting the provision of electricity are as follows:

Ordinance of 1890 (O.G. no. 19, year of 1890)
Ordinance of 1934 (O.G. no. 63, year of 1934)
Act No. 19 of 1960 (O.G. no. 5, 1989, year of 1960)
Government Regulation no. 19 of 1965 (O.G. No. 39)
Act No. 9 of 1969 (O.G. no. 40, 1969, 2904, year of 1969)
Government Regulation no. 11 of 1969 (O.G. No. 20, year of 1969)
Government Regulation no. 30 of 1970 (O.G. No. 42, year of 1970)
Government Regulation no. 18 of 1972 (Superseded by Regulation No. 17 of 1990)
Presidential Decree no. 59 of 1978
Government Regulation no. 36 of 1979
Government Regulation no. 54 of 1981 (Superseded by Regulation No. 17 of 1990)
Decision of DGENE no. 0236/47/500/1983
Decision of DGENE no. 0237/47/500/1983
Law no. 15 of 1985
Government Regulation no. 10 of 1989
Government Regulation no. 17 of 1990
Presidential Decree no. 21 of 1990
Presidential Decree no. 37 of 1992
Government Regulation no. 02.P/03 of 1993

*Presidential Decree No. 37 of 1992
*Regulation No. 02.P/03 of 1993

If a private power enterprise sells electric power directly to the public pursuant to an Electric Power Enterprise Permit (IUKU), the minister establishes its geographic service area in which it may market its power.[27] The right of industries to employ cogeneration for their own use is protected, regardless of who their electricity supplier is.[28] Private power enterprises are required to interconnect with the utility where possible.[29] The mandate to interconnect in Indonesia is placed on the independent producer.[30]

4. Number and Capacity of SPP Interest and Applications

The 1996 initial award solicitation allocated 906 MW across Java-Bali and eight regional grids on other major Indonesian islands. Solicitations could also come from other isolated systems that were not grid-connected. More than 70 SPPs responded by offering more than 1100 MW in eligible projects.

5. Criteria for Award

Applications needed to be complete and the application fee paid. Renewable resources were afforded a preference in the award criteria. There were four tiers of priority, with renewable energy at the top, fossil-fired cogeneration in the middle tiers, and conventional noncogeneration fossil fuels at the lowest tier. In other words, each region under regulation would award entitlements to sell SPP power to PLN from completed applications first from the top-tier renewable resources, proceeding down the hierarchy until the resources solicitation was filled with available resources. The award process fills up the queue first with renewable resources, and then proceeds to accept additional small power resources in lower tiers.

6. Award Data

From these more than 70 applications representing more than 1,000 MW, only 44 projects from 27 different developers were selected for a contract, constituting 281 MW. This represented a selection rate of 26 percent of project capacity offered and fulfilled only 31 percent of PLN's purchase obligation. Three of the eight regions did not agree to purchase any capacity, either because they did not participate in the program, they rejected summarily all applications, or they refused to sign any firm power contracts after running the process. Java-Bali, the primary island grid that serves 75 percent of the country's population, accepted only 13 percent of its required capacity allocation, constituting only 19 percent of what it was offered. The reason stated by PLN was a claim that most of the applications did not comply with application protocol. An independent evaluation found little corroboration of this stated reason. More than 802 MW of offered capacity were rejected by Java-Bali and the regional utility divisions, resulting in a significant underaward from that set forth in the World Bank loan commitments for the program.

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[27] Ministry of Mining and Energy (1993), Article 43. This regulation was promulgated to execute Presidential Decree No. 37/1992. Ministry of Mining and Energy (1993), Article 1.

[28] Ministry of Mining and Energy (1993), Article 45. "Cogeneration" is defined as a process where all thermal energy produced by or recovered from a turbine is used for an industrial production process. This diverges from the definition in U.S. federal law, which (a) does not require that all thermal energy be used (only a percentage of total energy must be usable thermal energy), and (b) does not require that use must be in an industrial production process (space conditioning or other useful employment of thermal energy is allowed).

[29] Ministry of Mining and Energy (1993), Article 46. The equipment specifications of the Indonesian Electricity Standards, and any other standards approved by the minister, govern the interconnection.

[30] 18 C.F.R. 292.303(c)(1).

7. Size and Type of Technologies

Of those projects selected and awarded contracts, totaling 280 MW, and those 802 MW of applications rejected, the winners and losers were from the sources shown in table 11.

Table 11: Indonesia SPP Awards by Type of Energy

Source	*Award winners (MW)*	*Award rejections (MW)*	*Total (MW)*
Hydro	165.5	288.2	453.7
Geothermal	45.5	10	55.5
Biomass	69.5	0	69.5
Conventional fuel	0	500.7	500.7

The size of projects accepted on Java-Bali ranged from 1.5 to 30 MW in size. In the five other regions that actually made award selections (as opposed to the total that were supposed to make award selections), the size selected ranged from 1.5 to 15 MW in size.

The data above reveal that although all biomass, most geothermal, and more than half of the hydroelectric project applications were accepted, all of the cogeneration and conventional power generation applications were rejected. This occurred, even though the program was designed to accept applications up to 30 MW of all types until the program capacity was fully subscribed. There is no technical explanation as to why every nonrenewable energy project and cogeneration project was either denied, disqualified, or ignored.

8. Completion Ratio and Reasons for Failure

PLN or the government, or both, made a series of unilateral changes in the PPA that undercut project financeability. This was compounded by the 1997–98 economic recession in Indonesia and across several Southeast Asian countries, and by Indonesian political turmoil.[31] The entire program was suspended in 1998 as a result of these factors, any one of which alone would have severely compromised any program roll-out.

Some signs of life later appeared. In 2002 PLN agreed to purchase power from SPPs under these SPP regulations (referred to as PSKSK Regulations in Indonesia) if the maximum capacity of the plant is no more than 1 MW. However, the purchase rate offered was 20 percent below the average total cost of generation of PLN. Contracts are no longer offered at full avoided cost.

9. Process Transparency

The standardized contract is meant to offer a standardized form and be simple and transparent. It is designed to apply to any independently financed and owned small private power enterprises anywhere in Indonesia. To achieve standardization, it was decided to have a single contract form. To make the contract transparent and easier to understand, traditional "legalese" ("party of the first part" and so forth) was replaced with more common and straightforward terminology. To make the contract simple, effort was made to shorten it to the extent possible.

[31] Indonesia was hit hardest by the 1997 financial crisis among Southeast Asian developing nations. World Bank (1998), p. 2.

The program as designed was particularly transparent and would have succeeded, except that several changes in the PPA were subsequently made by PLN that made the PPAs potentially unfinanceable. These changes also compromised the level playing field that had been carefully created in the project design and legal documents.

10. Stakeholder Concerns

The stakeholder concerns were both with the arbitrary rejection of a significant number of applications, but also with the fundamental unauthorized changes in the PPA (described in more detail below) that changed the level playing field and rendered the PPA potentially unfinanceable. Numerous complete and meritorious applications were rejected or ignored. Others that appeared in hindsight less complete were awarded a contract. Summarized succinctly by category of comment, the stakeholder concerns about this program were as follows:

Treatment of Applicants

- PLN affiliates participated and were awarded contracts.
- Insiders had information.
- Some developers wanted to negotiate contract changes.
- There was resistance in regions to implementation.
- Developers were damaged by delay and uncertainty.
- Some regions would not consider fossil-fired power (25 percent of awarded capacity was allowed by regulation for fossil-fired power).
- No rationale for rejections were provided; some were rejected on technicalities or for no real reason.

Suitability and Financeability of SPP Contract after Unauthorized Revisions

- Local lenders rejected the unilaterally revised PPA.
- Lack of an official English language version of the final PPA was problematic.
- Contract changes were seen as unfair and unfinanceable.
- Capacity and energy payment changes in contract tariff clauses made the contract unbankable.
- There was a need to link tariff payments to a convertible currency for more than five years.

Suitability of the Tariff after Unauthorized Changes

- Revised tariff structure disadvantaged seasonal SPP generators.
- Revised tariff energy prices were no longer linked to oil prices posted by Pertamina (the Indonesian state oil company).
- Price stream uncertainty was a problem.

Fairness to Applicants

- There was favoritism in awards.
- Large IPPs got better prices than SPPs; some developers wanted equal treatment in contract terms and tariffs.
- Most proposals on Java were rejected without cause, forcing developers to absorb costs of arbitrary application process.

❖ The program was not operated with the transparency and fairness expected.

11. Lessons

Despite a beginning that achieved stakeholder consensus on the PPA and tariff design, changes made in the PPA unilaterally by the utility between the time of that consensus and the launch of the award process undercut the initiative. The changes made in the PPA all had the effect of making the payment terms and power sale less secure for the SPP. The elimination of an official English language version of the final altered PPA made it difficult for others to track the changes made, required various SPP sponsors to translate the PPA back into unofficial English language versions, and made lenders apprehensive about long-term commitments.

Even though the utility altered only a few PPA clauses, they were key clauses that established the power sale and payment scheme, and allocated risk of the venture. In a shorter-form PPA, there is operative legal language in almost every phrase. Changing key words and phrases can fundamentally alter the legal obligations and liabilities of the parties. For several reasons, including economic and political instability in Indonesia, none of the dozens of PPA award recipients was ever able to successfully finance, construct, or operate any of the SPPs, despite some having signed contracts.

Neutral and objective PPA and tariff design is essential to successful program implementation. If one seeks to attract private capital, the program design, PPA, tariff structure, and implementation must satisfy standards of lenders. The PPA is not infinitely fungible. To the contrary, it must satisfy a relatively precise set of criteria.

Power Purchase Agreements

The PPA as Originally Agreed among Stakeholders

In the analysis below of the PPA, the document is analyzed as originally agreed among the stakeholders before it was unilaterally modified by the utility.

The principal features of the agreements are given in table 12.

Table 12: Features of Indonesia SPP PPA before Later Modifications

Feature	*Description of SPP feature*
Basic provisions	
1. Parties	The contract is made directly between the state utility and the SPP.
2. Milestones	The SPP has a period of two years after receiving its necessary permits to achieve commercial operation.
3. Delivery of power	The utility must accept all delivered power as long as operated pursuant to Good Utility Practices, unless the system is not able to accept power.
4. Output guarantees	The SPP pledges to commit to deliver a set amount of peak and off-peak capacity in a firm contract. Nonfirm contracts are also available. If the facility is capable of generation, it must generate and deliver power to PLN. It may not divert power to other buyers.
5. Engineering warranties	Power must be delivered at 50 Hz within 5% of nominal voltage.
Sale elements	
1. Power quantity	In nonfirm contracts, there is no commitment of capacity, and energy is sold from time

Feature	*Description of SPP feature*
commitment	to time. In a firm contract for a period of years, the SPP is obligated to sell a dedicated quantity of dedicated capacity.
2. Metering	PLN owns the metering equipment. Telemetering is required. Independent third-party calibration is required. Meters are tested annually and require accuracy within 1%. There is established a hierarchy of which set of multiple meters is employed to measure the energy and capacity sold during each billing period, cascading to secondary metering sources when the primary metering is not within accuracy parameters.
3. Net metering or exchange	Not contemplated by the contract.
Risk allocation	
1. Sovereign risk and financial assurance	By contract, sovereign immunity is waived as a defense to suit. Otherwise, there is no limitation of sovereign risk.
2. Currency risk	As discussed below, there is indexation to the U.S. dollar currency exchange rate for capacity payments for the first several years. This allows repayment of the capital costs borrowed in foreign currency or to purchase foreign-produced generating equipment.
3. Commercial risk	The contract is set up so that the utility contracts for an entitlement of power, defined as a set amount of capacity plus its associated electric energy. The obligation to attempt to produce and deliver, and for the utility to take and pay for, that entitlement is absolute except for short justifiable interruptions on either side of the agreement.
4. Regulatory risk and change of law	Although there originally was a change of legal clause covering regulatory and tax changes to allow adjustment of the price term, that clause was later removed by the utility in alterations to the PPA designed by the consultant and previously accepted by all stakeholders.
5. Excuse and force majeure	Force majeure also is provided for both acts of God and other acts. The time limit for the maximum duration of a force majeure event is three years. This is at the most liberal extreme of the U.S. small power contracts surveyed. This provides more flexibility to attract small power producers. Force majeure is defined in a manner conventional for power sale agreements, including civil disturbance and failure of the sovereign to grant necessary permits. Failure to obtain necessary fossil fuel for the SPP or any other cause out of a party's control is also deemed to be a force majeure event. After 180 days, if not cured, the other party may elect to terminate after an additional notice of 90 days.
Transmission	
1. Transmission and distribution obligations	The SPP must deliver the power at its own cost to the delivery point, and pay for all interconnection and system protective costs. Since PLN is the only entity to whom the SPP may sell power, other than its host or otherwise allowed by license, there is no obligation of the utility to transmit power.
2. Interconnection arrangements	Two options are provided for interconnection at the election of the SPP. Either the utility can build and bill the SPP for the interconnection upgrades and equipment, or the SPP can construct the interconnection equipment pursuant to utility review and standards, and then dedicate such facilities to the utility. The latter option was the one implemented by the utility. If upgrades, repairs, or modifications are later required by the utility, the SPP must implement the same at its own expense.
Tariff issues	
1. Type of tariff	Energy was to be paid under all contracts at 100% of the utility's avoided cost, differentiated by region and based on actual data regarding the marginal source of generation for the utility in that region Capacity was paid at 100% of avoided capacity cost for renewable energy SPP projects, and 75% of avoided capacity cost for nonrenewable SPP projects. To share generation savings with PLN, the price to be paid

Feature	Description of SPP feature
	to the seller is set at 75% of avoided capacity cost to PLN for other than renewable energy projects. Therefore, for firm contracts, renewable projects received a higher power purchase price. For these projects, then, the capacity component is included in the on-peak price. This provides a substantial economic incentive to the private power producer to produce and to sell capacity at peak periods. This makes the price and contract terms simple.
2. Capacity obligations	Capacity obligations were paid only to firm contracts, which were defined as lasting between 5 and 20 years at the option of the SPP at the time of contract formation, with an entitlement of capacity and associated electric energy pledged by the SPP to the utility. The capacity component is fixed at the time of contracting. It reflects projected avoided capacity costs for the region at the time of contract execution. The capacity component escalates annually for the first five years, and can be adjusted upward thereafter.
3. Fuel price hedging	First, the energy component of the price changes automatically and instantaneously to reflect changes (up or down) in the price of no. 2 diesel oil, the marginal fuel for PLN. Pertamina (the Indonesian state oil company) pricing comprises this index. Second, the value of fixed and variable operation and maintenance adjusts with changes in the Indonesian consumer price index. A savings clause also is provided to dedicate the parties to finding replacement indexes if a Pertamina fuel price or a capacity price is no longer available during the term of the contract. This maintains the integrity of the contract if the chosen terms of reference are no longer available.
4. Update mechanism	Energy prices were updated annually for both firm and nonfirm contracts. For firm contracts for renewable energy, energy prices were guaranteed not to decline below 95% of the initial first-year price, but could increase to any level if the marginal fuel cost for the utility system increased. This was done to establish a floor underneath renewable energy prices so as to facilitate their financing. Many renewable energy projects have higher capital expenditures than some conventional projects. Since the capacity and energy payments in this program are based not on the SPP's capital costs, but on the utility avoided capital (capacity) and energy costs, these renewable energy projects do not receive a higher capital cost than the utility's alternative capital cost of generation. Therefore, they must recover some of this higher capital cost, in part, through the energy payments (as well as the capacity payments) in the PPA. This floor provides assurance for a prospective lender that stability in the power sale revenue stream can be maintained to retire debt. The capacity payment is altered annually to hold constant the local currency–U.S. dollar exchange rate for up to three years after execution of the contract, but prior to operation, and for up to five years after operation. After this period, the capacity payment escalates only if the avoided capacity cost established yearly by the utility escalates because of annual revisions. The purpose of this is to ensure the ability to repay the cost of capital equipment purchased abroad. Such annual revisions are calculated against the initial year of subsequently executed PPAs.
5. Tariff penalties for nonperformance	The SPP is liable for direct damages to PLN for not delivering firm power entitlement during periods other than a scheduled outage. These costs include the cost of replacement power, and in a protracted situation, costs of replacement capacity.
Performance obligations	
1. Operational obligations	The SPP must use its best efforts to deliver power. However, failure to deliver power for short periods, while justifying damages to the purchaser, does not rise to the level of a cause for termination. However, the tariff is structured to impose significant loss of revenue to the SPP if it does not deliver capacity on peak. Provided in this contract are

Feature	*Description of SPP feature*
	the following protections of PLN: ❖ Seller forecasts of power to be produced and sold. ❖ Seller information about SPP outages. ❖ PLN ability not to take power when necessary. ❖ SPP's operation in a manner consistent with PLN standards, codes, and Good Utility Practice. ❖ PLN ownership of metering equipment. ❖ PLN rights to facility access and inspection. ❖ Advance notice to PLN of interruptions in sale. ❖ Indemnification of PLN when the independent producer owns the interconnection facilities.
2. Definitions of breach	There are no express remedies provided for breach and no explicit penalties in this contract. Although a failure to supply capacity has significant economic consequences for the seller. Moreover, no deposits or other security are required of the independent producer. There are no rights for PLN to take over the small power facility in the event that power is not provided. Typical commercial definitions are employed. Breaches must be cured as soon as possible. A party has 45 days after notice to cure a breach, or if it requires longer, such cure must be begun within 45 days and the cure accomplished within no more than 2 years. Failure to pay within 90 days is a breach.
3. Termination opportunities	Termination may not be made at the sole election of either party without cause. Cause for termination includes only uncured default, uncured nonpayment, or uncured force majeure.
4. Guarantees of payment and performance	The Agreement contains no guarantees of any performance obligations.
5. Assignment or delegation	Other than to subsidiaries for purposes of financing, the SPP may not assign or delegate its rights without the prior written consent of PLN, which may not be unreasonably withheld. A succession clause is included which has any successor to PLN assume its duties and rights regarding the contract.
6. Dispute resolution	The purpose of the dispute resolution provision is to keep the matter out of the Indonesian court system. The parties first pledge to attempt to informally settle any dispute among themselves during a period of 60 days. If not settled, the dispute is referred to the director general of the subministry of electricity. If not then resolved within 90 days, either party may refer the dispute to the Indonesian National Board of Arbitration, which will make a final determination.

The Subsequent Unilateral Modification of the PPA

The problem with the Indonesia program was not in program design, the tariff, or the PPA as originally designed and approved in the World Bank loan covenant. Later changes were made in the PPA unilaterally by PLN before it was implemented. At the end of this process, the contract was fundamentally changed and was only available in the Indonesian language. The critical changes were as follows:

❖ The tariff was altered to remove its set escalation provision, instead providing that it will be reviewed annually, with no indication of what will happen.

- ❖ The tariff had added a capacity factor multiplier that operated as a limitation on SPP capacity revenues so as to substantially reduce the price paid to the SPP proportionately to its achieved capacity factor (between 50 and 99 percent of capacity).[32]
- ❖ The limitation of a required minimum capacity factor of 50 percent was added.[33]
- ❖ A 120 hour per month limitation on SPP outage was added as a limitation on receipt of capacity payments by the SPP.[34]
- ❖ A four-month cumulative annual threshold for the 120 hours per month limitation on SPP outage was added as a restriction on capacity payments for the SPP for the ensuing year (in addition to forfeiting monthly capacity payments).[35]
- ❖ The tariff was changed to allow alteration of the energy price each year, or to reduce the energy price to 95 percent of full avoided cost in the year of contract execution; previously full avoided cost pursuant to a set formula was provided.[36]
- ❖ PLN was able to refuse taking firm power under several contingencies at its sole election.[37]

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[32] Revised PPA, Article 2, Clause 3: Capacity Factor Limitation. A new clause has been added that allows PLN to annually set or restrict the capacity factor that governs the facility's payment eligibility.
[33] A capacity factor is a new concept added to work a reduction in the amount of compensation received by the SPP to reflect its actual capacity factor of delivery.
[34] Revised PPA, Article 5, Clause 3: Loss of Monthly Capacity Payments. A new provision states that if there are 120 hours of nondelivery outside of the scheduled maintenance and repair (which now requires prearrangement with PLN, which previously was not the case), the SPP loses all capacity payments for that month. If the SPP loses 16 percent of the operating time in a month (equivalent to five days) either continuously or intermittently, as a result of machine failure, failure to get fuel, or even failure of the PLN transmission system, 100 percent of the capacity payments are lost for that month. Achieving an 83 percent monthly availability factor, which by itself is not seen as problematic for most utility systems, results in loss of capacity payments. A capacity factor is already factored into the tariff. This provides PLN the ability to avoid routine. delivery by the T&D system for which it is responsible.
[35] Revised PPA, Article 5, Clause 4: Loss of Annual Capacity Payments. Another new provision provides that if the 120-hour failure occurs four or more times in any contract year, the SPP not only loses all capacity payments in those four (or more) months, but also loses the capacity payments for the entire ensuing year.
[36] Revised PPA, Article 5: Deletion of Continuation Clause. A provision in the original contract—that provides that if an index fails of its essential purpose, it will be replaced by the parties so that the contract can continue to function as intended—has been deleted entirely.
[37] Revised PPA, Article 1: Definitions: Firm and Non-Firm Capacity. The definition of firm capacity was altered so that PLN is able to refuse the delivery of energy from an SPP if it has no need for the energy after the contract is formed and in force.
PLN Entitlement. The definition of PLN's entitlement was changed from the capacity and energy committed, to the capacity and energy *sold.* This change shifts significant power to the power purchaser to not take power.
Revised PPA, Article 1, Clause 6: Power Purchase. In the original version, PLN could only temporarily interrupt accepting power where that was necessary and consistent with good industry standards. In the revised version, that stoppage can occur for any reason that PLN deems necessary.
In both the original and utility-revised versions of the PPA, Article 2, Clause 7: Purchase Cessation. The original version contained a provision [Art. 2 (g)] designed to protect the power seller by limiting PLN's refusal to take power to situations absolutely necessary, and with maximum possible notice. This has been replaced by two provisions that allow PLN not to take power (as long as it does not count against the capacity factor concept that PLN has added to this contract), and a provision that states that if the Seller does not cut power delivery

❖ Alterations against the SPP were made in the change of law and force majeure provisions.[38]

❖ Sovereign risk and enforceability were compromised for the SPP.[39]

Some of these elements are also now in other programs, such as a variable capacity factor adjusted based on performance (Thailand) and annual buyer adjustment of tariff without a contractually established formula. No one of these changes was necessarily fatal, but added together, they tilted the balance of power among the parties within the PPA, and made it very difficult to obtain conventional financing. With a stable economic and political climate, the PPA could have been reoriented as necessary and the program continued.

However, it is worth emphasizing that the Asian financial crisis in 1997 and thereafter, alone, would have undermined this SPP program. The changes in government also undercut necessary program continuity. With an oversubscription of large IPP power by the government, executed at ad hoc rates and with ad hoc PPAs, there was surplus power under contract when the financial crisis and recession hit.[40] The SPP program then having just completed the award of contracts, was a marginal casualty, and never moved forward.

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when asked (presumably for any reason) by PLN, PLN will cause that amount of power delivery to be cut for the power seller.

Revised PPA, Article 5, Clause 1: Tender of Power. The obligation of the SPP power seller has been changed from *tendering* to *delivering* power to PLN. Delivery is actual provision and surrender of the power. Tendering is evidencing a present capacity and capability to deliver power. A seller of power may wish to tender power and receive a corresponding tender of payment from the power buyer, to be assured that payment will be forthcoming. If delivery of power is required, to prevent breaching the contract, the seller will have to deliver power before receiving an assurance that payment for the power will be forthcoming.

[38] Revised PPA, Article 5, Clause 18: Change of Law. A provision was added that indicates the SPPs are susceptible to any change of law or tax, without adjustment in the SPP contract.

Revised PPA, Article 6, Clause 1: Force Majeure. Omits failure of the PLN system as a force majeure event that could be claimed by the SPP failing to deliver power. The following changes also were made in the revised PPA to the force majeure provisions:

- Omits acts of God, fire, explosion, failure of the fuel supplier, and uncontrollable events as force majeure.
- By changing the language, the failure of PLN to pay money owed to the SPP now could be an event of force majeure, where before in the contract, and typically, this is not recognized as an event of force majeure.
- There is an added a requirement that a relevant public authority provide an explanation of the force majeure.

[39] Article 3, Clause 2: Enforceability: Sovereign Risk. A provision has been deleted that provided that contesting the basic enforceability of the SPP contract constituted an event of default. The requirement to give written notice of default to the defaulting party, and to allow its lenders to cure the default within a reasonable time, is deleted. The definition of Commencement Date of Operation was changed to give PLN the power to agree on when this has occurred for the SPP project, with no requirement that PLN agree at any particular time or circumstance. The former version had this occur automatically when the facility began operation.

Revised PPA, Article 5, Clause 12: Dispute Resolution: Whereas before, amounts due could be contested up to one year, that provision for contest has now been reduced to seven days. There is no provision for regular calibration of the meters, given other changes that have been made to the standardized contract.

[40] Wholesale tariffs for private large IPP power projects ranged between 5 and 8.5 cents per kWh during the long term. At the same time, retail rates charged by PLN to customers were just slightly more than 7 cents per kWh. Indonesia was hit hardest by the 1997 financial crisis among Southeast Asian developing nations. PLN responded by trying to lock payment rates at the old rupiah–dollar conversion rate, which was only one-third of the rate after the rupiah fell during the financial crisis (World Bank 1998, pp. 2 and 5).

5. INDIA

Program Overview

In **India,** about 42–44 percent of the rural population has access to electricity.[41] There is significant variation in access to electricity across various groups in different states of India.[42] Rural electrification on an ambitious schedule will require that private sector, renewable, and off-grid resources be encouraged and deployed.

In mid-2003, the federal Electricity Act of 2003 was enacted.[43] It consolidates electricity laws and regulation embodied in federal legislation. It requires a license to generate and distribute electricity, except that in rural areas no such license is required, as long as the distributor follows any pre-established requirements of the Central Electric Authority. Any generating company may construct and operate a generator without obtaining a license, as long as technical grid standards are observed.[44] Transmission, distribution, and trading of electricity require a government license.[45] State commissions are directed by the Act to facilitate the transmission, wheeling, and interconnection of electricity within the state.[46]

India has become a major player in renewable generation and private sector power development. India is the tenth largest developer of small hydro facilities, and the fifth largest developer of wind power, as well as the fifth largest producer of PV systems, in the world.[47] In India, state electricity boards provide electric power. Much of the authority for electricity policy resides at the state, rather than federal, level. A number of states have SPP programs.

What is particularly novel about the Indian system is twofold: First, it operates through the close coordination and integration of programs and policies at both the state government and federal levels. Second, it has the most complex system of subsidies and financing arrangements for renewable energy investments of any of the Asian nations.

Subsidies

The federal government Ministry of Power in 2000–01 initiated a program called Accelerated Power Development Program, providing financial assistance to the states for modernization programs. To

[41] Ministry of Power (2003), p. 8. This leaves almost 80 million rural households without access to electricity. Notwithstanding this statistic, as of March 2003, 87 percent of inhabited Indian villages were declared electrified.
[42] Ministry of Power (2003), p. 1. There is a government policy of universal access to electricity by 2012. Ministry of Power (2003), p. 8.
[43] The Electricity Act (2003) aimed "to consolidate the laws relating to generation, transmission, distribution, trading and use of electricity…promoting competition…promotion of efficient and environmentally benign policies…."
[44] The Electricity Act (2003), Section 7, p. 9. Certain conditions are imposed on the development of hydroelectric generations to ensure the highest use of water resources for competing uses. The Electricity Act (2003), Section 8, p. 9.
[45] The Electricity Act (2003), Section 12, p. 11. Conditions may be imposed on the license. The Electricity Act (2003), Section 16, p. 13.
[46] The Electricity Act (2003), Section 30, p. 19. An appellate tribunal is also established to handle appeals of an order of the regulatory commissions. The Electricity Act (2003) Section 110, p. 53. State governments are authorized to constitute special courts to expedite trials of those who steal or divert electricity. The Electricity Act (2003), Section 153, p. 68.
[47] India now exports its wind and PV technology (from confidential World Bank data and reports, 2002).

receive assistance, the beneficiary state has to undertake certain reforms that promote a rationale power administration at the state level and promote renewable energy technologies.

The Ministry of Non-Conventional Energy Sources (MNES) at the federal level promotes through grants and subsidizes renewable power, so as to create a level playing field for various energy sources. MNES can subsidize state-owned (not private) renewable energy projects through grants to state governments, electricity boards, and transmission companies (TRANSCOs):

- Up to 60 percent of the cost of wind turbine equipment.
- Up to Rs. 15,000 per kW ($320 per kW) for microhydro and up to double this amount for minihydro up to 3 MW(not to exceed 50 percent of project cost) and up to 100 percent of site survey expenses.

For private or public projects, MNES can provide grants to subsidize interest rates:

- Grant subsidies of Indian Renewable Energy Development Agency (IREDA) interest rates by a reduction of 1–3 percent for biomass and bagasse projects.
- Reduction of IREDA interest rates for waste-fueled projects down to 7.5 percent.
- Reduction of IREDA interest rates for PV projects down to 5 percent.[48]

Certain renewable energy technologies also receive preferential federal tax treatment.[49] MNES also issued guidelines for tariffs to be offered by state electricity boards to purchase renewable energy SPP power. This federal recommendation is not based on an avoided cost or long-term marginal cost calculation. These recommendations provide a certain amount of common starting points, but states do vary the actual tariffs by as much as 50 percent.

MNES estimates that the potential and realization to date of renewable energy sources in India is as set forth below.[50] The government is considering setting a national goal to achieve a minimum 10 percent renewable energy share by 2012.[51] IREDA, a MNES-owned renewable energy financing agency has received funding assistance from the World Bank, the Government of the Netherlands, the Asian Development Bank (ADB), the Danish International Development Agency (DANIDA), Bank for Reconstruction (KfW) Germany, and the Overseas Economic Cooperation Fund (OECF) of Japan.[52]

Table 13 scales the realization of various renewable energy development in India, as of 2003, against its potential.

Table 13: Realization of Renewable Projects in India, as of 2003

Technology	*Potential (MW)*	*Realization (MW)*
Wind	45,000	1,267

[48] MNES (2001), "Business Opportunities," pp. 59–71.

[49] MNES (2001), pp. 53ff. Wind energy components pay a much lesser customs import duty than assembled wind generators, whereas PV systems are exempt from excise duty. The depreciation for solar devices, biogas equipment, wind turbines, and agricultural and municipal waste conversion equipment are allowed accelerated depreciation. MNES (2001), p. 57.

[50] MNES, "Renewable Energy in India," 2001, p. 1.

[51] MNES (2002), p. 4. It also has a goal to provide electric power to remote villages through the deployment of stand-alone renewable energy systems. MNES (2002), p. 6.

[52] MNES (2001), p. 42. Assistance to projects is provided in the form of debt instruments up to 80 percent of project cost or 90 percent of equipment costs, at interest rates varying at different levels below 15 percent for a period of up to 10 years with a 3-year repayment moratorium. MNES (2001), p. 43.

Small hydro up to 25 MW	15,000	1,341
Biomass power	19,500	308
Biomass cogeneration	3,500	273
Urban and industrial waste	1,700	15
Photovoltaics	Significant	47

Several of the states provide other state-level renewable energy subsidies, such as a cogeneration subsidy, sales tax exemption on generation equipment, or no tax or duty for a period of years on electricity sales where direct third-party sales are allowed.[53] Renewable resource development proceeded most vigorously not where the renewable energy regime was best, but where the state policies were most favorable. Today a majority of renewable energy development in India is undertaken by private and nongovernmental organizations.

Financing

The significant penetration of renewable SPPs in certain Indian states is in part a function of programmatic encouragement of such projects at the state level, but it is also promoted by a series of subsidies and financing originating at the federal level, although often administered by the states. MNES provides direct subsidies, and PV subsidy has been advanced by the Global Environment Facility to IREDA, which has enjoyed the infusion of more than $350 million in international support.[54] MNES develops promotional policies for renewable energy wheeling,[55] energy banking,[56] and third-party retail sales,[57] which are recommended to the states for implementation.

Arising from a base of almost zero financing, during the past decade, IREDA and multiple other lenders have created a liquid market for renewable and SPP power developments in India.[58] For SPP and IPP

[53] MNES (2001), "Business Opportunities," pp. 59 and 63.

[54] From confidential World Bank data and reports, 2002; Government of India. Funds to IREDA have been provided by the World Bank, GEF, IBRD, ADB, KfW, and the Japanese Bank for International Cooperation. IREDA (2001), pp. 20–21. The types of financing offered to private developers by IREDA include project or equipment financing, and umbrella financing (IREDA 2002b, p. 2). Where international or bilateral funds are loaned by IREDA, the donor requirements and stipulated procedures are imposed on the borrower as conditions of the loan. IREDA 2002b, p. 6.

[55] Of nine Indian states surveyed, all have implemented the MNES recommendation for energy wheeling at a charge of 2 percent of wind energy wheeled, with two states raising the charge to 12.5 percent and 20 percent (and one state not allowing wheeling) for biomass power, such 2 percent charge to compensate for line loses (MNES 2001, "Business Opportunities," p. 59).

[56] Of nine Indian states surveyed, eight allow energy banking for wind power for a period of 6–12 months. For biomass power, energy banking is allowed among those 8 states for 8–12 months in 6 states and for 24 months in Uttar Pradesh state. Energy banking carries a 2 percent charge assessed as a deduction in net power wheeling in Andhra Pradesh and Tamil Nadu states, as discussed below (MNES 2001, "Business Opportunities," p. 59).

[57] Of nine Indian states surveyed, five allowed direct third-party retail sales of power for wind, whereas seven allowed such directs sales for biomass energy (although Andhra Pradesh, discussed below in more detail, has since suspended this privilege).

[58] IREDA is an independent specialized public sector lending agency under MNES, incorporated in 1987. IREDA loans to private SPPs and IPPs must be secured by a loan guarantee from a commercial bank, a secured equitable mortgage hypothecated against all of immovable project assets plus a subordinated lien (second to other project lenders) against all existing and future movable project assets plus project developer guarantees, or irrevocable guarantees by Indian public financial institutions (IREDA 2002b, p. 7). The mortgage applies even to projects on government-owned land, or if not possible obtains a letter of assurance from the state government owning the

renewable energy projects, IREDA loans offers a variety of terms.[59] The most favorable terms (interest rate, repayment moratoria, percentage of project debt extended) are provided to the most expensive-per-installed-unit projects (such as PV, off-shore wind demonstration, fuel cells, smaller installations). The more currently cost-effective technologies are provided IREDA loans that are at interest rates close to commercial lending rates.[60]

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land. IREDA 2002b, pp. 18–19. Until such mortgage is executed, the borrower is charged extra points on the loan interest rates. A bank guarantee or pledge of fixed deposit receipts (FDRs) must be for at least 10 percent of the IREDA loan amount. IREDA 2002b, p. 20. Less demanding loan provisions as to interest rate and loan origination fees are imposed on SPP project entities owned by women, ex-servicemen, and handicapped individuals, to promote their participation in the sector, as well as on SPP projects located in certain economic development zones or remote areas. IREDA 2002b, pp. 24–28. IREDA will also provide SPP generation equipment financing and equipment export promotion. These loans are eligible for prepayment by the borrower. About 10 percent of IREDA loans are colent with a commercial bank. Most loan applications to IREDA are brought forward by a particular state nodal agency working with IREDA. IREDA 2002b, p. 38.

[59] The terms of IREDA loans are set forth in the table below:

Terms of IREDA Renewable Project Loans, 2003

Technology	*Interest rate (%)*	*Loan term (years)*	*Moratorium on repayment (years)*	*Maximum amount of loan*
Hydro				
<1 MW	13	10	3	75% of project cost or 100% equipment cost
1–5 MW	13.25	10	3	70% of project cost or 100% equipment cost
5–15 MW	13.5	10	3	Same
15–25 MW	13.75	10	3	Same
Wind				
Leased	12.75	10	1	70% of project cost
Ownership	12.5	10	1	70% of project cost or 100% of equipment cost
BOOT basis	11.75	10	1	70% of project cost
Off-shore demo	11.5	10	2	70% of project cost
Biomass cogeneration	13.25	10	3	70% of project cost
Waste to energy				
Industrial waste	13.5	8	2	70% of project cost
Municipal waste				
< 3 MW	12	10	3	
3–6 MW	12.5	10	3	70% of project cost
Fuel cells	11.5	8	2	70% of project cost
Photovoltaic	14*	10	1–2	80–85% of project cost

* With MNES subsidies, the effective interest rate for PV is 5%.

IREDA 2002b, pp. 54–63.

[60] IREDA provides an essential function in extending debt to a sector of the economy that previously had difficulty in accessing local credit on sufficient terms. In this way, not only has IREDA lending facilitated essential renewable energy project development by funneling multilateral and bilateral funding, it has also provided a lending model for the local commercial banks in India. Therefore, it has served as a catalyst, as well as a primary lender to the sector. For example, small hydro development is the most significant renewable energy resource currently deployed in the world—and the densest renewable resource. Four hundred million tons of

More than 3,400 MW of renewable projects were in operation by the end of 2001, from a base of about 100 MW in 1992 before these initiatives began.[61] Thirty-five small hydro projects of about 118 MW, 27 wind projects for 87 MW, and 78 PV projects for 2 MW were financed by IREDA.[62] IREDA has sanctioned loans of about Rs. 5,000 crore ($1.05 billion), and disbursed about half of this, to support 844 MW of renewable power development.[63] About 25 percent of renewable energy development in India has been assisted by IREDA financing.[64] Currently, wind developers report that they are able to borrow commercially at less cost than IREDA rates.[65]

As part of this analysis, we evaluate the program in two Indian states: Andhra Pradesh and Tamil Nadu. Andhra Pradesh is the most advanced in installing wind capacity, whereas Tamil Nadu is the fourth most successful in wind capacity.[66] The experience in each of these states illustrates the very creative application of financing sources and state subsidies to successfully promote renewable SPPs, which has become a hallmark of the Indian program. Although each of these states has an advanced SPP program, neither is among those states in India that does permit direct third-party sales. Some states in India have cut back on the ability for third-party wheeling or net metering, because the utilities were losing their best-to-serve customers. Each of these two states is examined separately.

Andhra Pradesh

The sections below detail all the relevant provisions of the SPP program and tariff in Andhra Pradesh.

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agricultural waste is produced annually in India; biomass electric generation is CO_2 neutral (IREDA, "Biomass Power Generation Guidelines for Loan Assistance," 2002). Also, 27.4 million tons of municipal waste per year and 12,145 million liters per day of liquid municipal waste (sewage) are generated in India (IREDA, "Waste to Energy Guidelines for Loan Assistance," 2002). India has more than 400 sugar mills capable of generating an additional estimated 3,500 MW of surplus power from biomass sugar cane waste, if developed (IREDA, "Biomass Based Cogeneration Guidelines for Loan Assistance," 2002). IREDA has sanctioned the following number of projects by technology:

Technology	*Projects sanctioned*	*MW sanctioned*	*Projects installed*	*MW installed*
Small hydro	101	311	48	147
Wind		651		1625
Biomass	28	166		88
Biomass cogeneration	31	445		227

[61] MNES (2002a), p. 7; from confidential World Bank data and reports, 2002. This increased the percentage of renewable energy in India from 0.13 percent in 1992 to 3.4 percent in 2001. Wind accounts for almost half of this renewable capacity; 26 interconnected PV projects are in service. In addition, there are 400 sugar mills where renewable energy cogeneration are possible, as well as a potential of 16,000 additional biomass opportunities. MNES (2002a) There is estimated to be the potential for 15,000 MW of small hydro potential (of 25 MW each of larger). MNES (2002a), p. 7.

[62] From confidential World Bank data and reports, 2002. Renewable wind projects enjoy 100 percent tax depreciation at the national level, and subsidy in some states such as the deferral of sales tax payments. These incentives are being scaled back as the renewable energy sector matures.

[63] MNES (2002a), p. 9.

[64] IREDA (2002b), p. 2.

[65] Personal interview with wind power developers (2002).

[66] MNES (2001), p. 8.

Program Design and Implementation

Andhra Pradesh is a system of more than 7,000 MW that is short of capacity to serve existing demand. Its demand curve is relatively flat, with a slight peak from 6 to 9 p.m. daily. During this afternoon peak, system voltage drops. Inflation is running at about 6 percent annually, and the rupee depreciates against the dollar by about a little less than that amount annually.

1. Solicitation of SPP Participation Mechanism

In some other Indian states, such as Himachal Pradesh, Haryana, and Uttar Pradesh, formal bid packages for SPPs were prepared and sold to potential project developers. In Andhra Pradesh, there was no formal solicitation or bidding; project developers could submit requests that were independently judged. Applications for a contract can be submitted at any time on a standardized form. The transmission utility, Transmission Corporation of Andhra Pradesh Limited (APTransco), which is distinct from the state electricity board—APSEB, the distributor—unilaterally makes the initial decision on whether to enter a PPA with an SPP developer. This same entity that makes this decision selects the rate it is willing to pay to purchase the power from such a facility, and negotiates a PPA with the project.

2. Size and Resource Limitations

SPP project eligibility was originally for projects up to 50 MW, and has since been lowered to a 20 MW maximum. Any renewable or nonconventional waste technology is eligible.

The amount of power sought is distinguished by size. The amount of participation by wind and small hydro projects is unlimited in the program design. There are, however, limited wind resource potential, and suitable hydro sites are limited by environmental considerations in Andhra Pradesh. For purposes of economic and social policy, rice husk biomass projects are limited in each district of the state to employ no more than 25 percent of the rice husk residue. This is because rice husks are also employed for cooking fuel in households and for insulation of ice slabs to transport fish. Diverting a more significant percentage of risk husks to small power generation would cause the price of husks for residential and other commercial purposes to increase. Cogeneration is considered a high-priority resource.

3. Power Authority Role

The State of Andhra Pradesh is promoting renewable and nonconventional power generation resources pursuant to the Andhra Pradesh Electricity Reform Act of 1998 (Act No. 30 of 1998). It empowers the Andhra Pradesh Electricity Regulatory Commission (APERC), and it also created the Non-Conventional Energy Development Corporation of Andhra Pradesh (NEDCAP) to further this goal. NEDCAP operates under the Principal Secretary for Energy of the Government of Andhra Pradesh. It makes grants for renewable energy projects with funds provided by the Ministry of Non-Conventional Energy Sources (MNES) through NEDCAP, the local nodal agency.

To facilitate SPP financing, NEDCAP coordinates the projects of IREDA, a federal government agency. IREDA lending was supported by the World Bank and the Global Environment Facility. Since 1997 IREDA has supported 221 projects for Rs. 11.16 billion (Rs. 1,116 crore; $231.5 million; given in billions of rupees and U.S. dollars, Rs. 11.16 billion) in Andhra Pradesh.[67] IREDA operates with the dual goals of renewable technology promotion and financing. Funding at conventional interest rates is available from IREDA, the financing wing of MNES. Prior clearance from NEDCAP is required for IREDA financing.

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[67] IREDA (2001), p. 32.

The Andhra Pradesh Electricity Regulatory Commission (APERC) issued G.O.MS No. 93 of 1997, and G.O.MS No. 112 of 1998, as extended, which provide the rates paid to Non-Conventional Energy Projects. The 1997 Order is designed to encourage renewable energy resources, by establishing a power purchase price of Rs. 2.25 per kWh, escalating at 5 percent per year. It also allows third-party sales and energy banking. However, the 1998 Order clarifies that, in the absence of the grant of a license pursuant to the Electricity Duty Act of 1939, SPPs cannot make third-party sales.

4. Number and Capacity of SPP Interest and Applications

There is no reliable data on the number of applicants. APTransco is willing to commit to up to 2,222 MW of total nonconventional energy.

5. Criteria for Award

The applications are evaluated by APTransco. If they are deemed viable, APTransco negotiates an individual power purchase rate and contract. Appeals by the SPP applicants have gone to the APERC and to the courts. Some cases are pending before the courts as to the rates set.

6. Award Data

Andhra Pradesh has approved the construction of 1,013 MW of nonconventional generation. This is scaled against the potential in table 14.

Table 14: Andhra Pradesh Renewable Project Status, 2003

	Capacity (MW)			
Technology SPP	*Projects approved*	*Projects complete*	*Projects at finance close*	*Potential capacity*
Wind	283	92	10	745
Biomass	345	81.5	110.7	627
Bagasse cogeneration	210	49.5	75.5	250
Municipal waste	23.6	0	0	40
Industrial waste	36	1.5	4	135
Small hydroelectric	95	69	30.4	1,252

7. Size and Type of Technologies

See table 14.

8. Completion Ratio and Reasons for Failure

To date, 189 MW of capacity are in operation; the remainder is in various stages of development. Because of the lack of a standardized contract or tariff, some projects have ended up under appeal at the APERC or in the courts. Projects must secure land clearance from the municipal body and any required environmental clearance from the State Pollution Control Board.

9. Process Transparency

There is no standardized contract. There are general guidelines for the contract issued by APERC and APTransco. Contracts are negotiated case-by-case. There is a generalized interconnection agreement, which is not required to be standardized. The SPP PPAs are not publicly available. This adds to the inability to achieve consistency or to minimize legal and other transactions costs.

10. Stakeholder Concerns

SPP developers have been disappointed with the results of the process in some cases. There is no formal standardized contract. Therefore, individual negotiation occurs with the state utility monopoly to determine the contract terms. Similarly, the state utility makes the determination of the purchase rate it will offer the SPP. The utility has attempted to abrogate existing PPA tariffs. Aggrieved SPPs have taken appeal of the rate to APERC, which has set the rate on appeal. Decisions of APERC have been appealed by aggrieved SPPs to the Supreme Court. Wind project developers report that they require a constant, unchangeable, standardized PPA to allow them to finance new projects during a 5- to 10-year loan period. The 80 percent year 1 depreciation deduction, along with PCF incentives, is enough to make wind projects viable with a set PPA enforced by the regulator.

11. Lessons

The role of the independent regulator is essential. APTransco is attempting to void some prior PPAs and tariffs at PPA rates that it now claims are above its average cost of generation. In discussions, it indicated that it would prefer not to purchase power from SPPs.[68] APTransco has staked out a position opposed to certain expansion of renewable energy SPPs.[69] These issues are now before APERC and in court litigation. In one case, the court disallowed the SPP the opportunity to make a third-party retail sale at Rs. 5.2 per kWh, but did uphold the obligation of APTransco to pay the stipulated Rs. 3.32 SPP power purchase price if it was objecting to a third-party retail sale by the SPP.

APERC is now considering SPP tariff revisions that would affect all existing PPAs and future SPP PPAs. Their criteria for setting the future tariff would be differentiation of SPP profitability by technology and necessary rates of return on investment. This would diverge from avoided cost principles. The resulting uncertainty has caused project development to halt. APERC has required APTransco to bring its current accounts payable into a more prompt payment for SPP power within 15 days.

Wind development in Andhra Pradesh has gone through cycles. Originally encouraged by tax incentives (100 percent first year depreciation), wind SPPs were often sited at mediocre wind sites. In 1997 the marginal corporate income tax rate was reduced; an alternative minimum tax was introduced, and some of these project became less viable. With delays in payment for power purchases by APTransco, many of these projects have had difficulty, some going into default on their loans.

The top priority for developers is the restoration of third-party retail sale authority for SPPs. APTransco has strongly resisted this because of the reality of “cream skimming” its best customers and because it claims first access to customers, since the retail rate it is allowed to charge is subsidized and does not recover all system costs.

[68] Personal communication (2002) in Hyderabad, Andhra Pradesh. It claimed that its marginal cost of new combined cycle gas-fired power to be about Rs. 1.8 per kWh ($0.035 per kWh). The utility also is concerned that they cannot control where SPPs choose to site projects.

Power Purchase Agreements

Since there are no standardized contracts in Andhra Pradesh, unlike the four other countries in this comparison, there is no standardized PPA to evaluate. Therefore, a representative PPA must be evaluated. Each Indian state operates its own SPP initiative if it so chooses. For the two Indian states evaluated here, PPAs for bagasse cogeneration SPPs of approximately 20 MW are discussed.

This PPA is the least specific and developed of those in the five countries evaluated here. This contract is very friendly to the SPP in one sense, in that it there is no performance obligation, and energy can be delivered at the will of the SPP.

The principal features of the agreements are given in table 15.

Table 15: Features of Andhra Pradesh SPP PPAs

Feature	*Description of SPP feature*
Basic provisions	
1. Parties	The contract is made between the SPP and the utility, APTransco. The agreement is for 20 years.
2. Milestones	Under its financial guarantee agreement with NEDCAP, the SPP is required to achieve financial closure within six months of signing a memorandum of understanding with NEDCAP and is required to begin construction within 15 months, of signing a memorandum of understanding with NEDCAP.
3. Delivery of power	Delivery occurs at the interconnection point.
4. Output guarantees	Operation of the project is totally within the control of the SPP. Power must be accepted by APTransco except for system emergency reasons. There is no warranty to deliver any energy or capacity by the SPP.
5. Engineering warranties	Power must be delivered at 50 cycles per second (-5% or +3%).
1. Power quantity commitment	No commitment whatsoever, either for energy or capacity, or both, is made by the SPP for power sale.
2. Metering	A pair of bidirectional meters are installed by the utility. Check meters are then installed by the SPP. Meter accuracy is checked twice yearly; meters are calibrated yearly. Where the primary meters do not register accurately, the check meters are utilized for billing purposes. Detailed meter testing is specified.
3. Net metering or exchange	Power can be banked for up to 12 months at a cost of 2% of the energy banked. This is fairly typical of other states in India. Wind produces power during summer months, which is peak period, making energy banking not a primary issue in this state. In 2002, rates were Rs. 3.32 per kWh (2.25 per kWh in 1993–94 rupees, at 5% escalation annually) given in U.S. dollars. This rate is next revised in 2003. This rate is fairly typical of other states, but among the highest. The SPP is entitled to standby and backup power supply at the High Tension tariff. In the past, direct third-party retail sales were allowed, but in 1999 they were suspended indefinitely and the prior arrangements annulled by APERC at the request of APTransco. The APERC issued an order, which prohibited direct third-party sales. Power may be sold only to APTransco at the rates that they prescribe. In other states, such as Karnataka, Madhya Pradesh, Maharashtra, and Rajastan, third-party SPP sales are permitted. Uttar

Feature	*Description of SPP feature*
	Pradesh, with commission approval, allows third-party wheeling without charge for the wheeler, for power sold at the same rate as that for centralized power supply. Other states, such as West Bengal, Tamil Nadu; Gujarat, and Kerala, do not allow third-party sales of private power. Tariffs are under development for third-party, high tension wheeling of power from IPPs to third-party consumers of high-voltage power. APTransco has allowed some wheeling in-kind. APTransco historically charged a 2% fee for wheeling. Other states typically charge 2–5%. Now, APTransco charges a 28.4% in-kind charge for the wheeling, which is the systemwide power line loss factor, plus Rs. 0.50 per kWh ($0.009 per kWh) paid in cash. At these high rates, SPPs are discouraged from wheeling power and are economically compelled to sell power to the utility.
Risk allocation	
1. Sovereign risk and financial assurance	No provision to protect against this risk is provided.
2. Currency risk	No provision to protect against this risk is provided.
3. Commercial risk	No provision to protect against this risk is provided.
4. Regulatory risk and change of law	No provision to protect against this risk is provided. The SPP remains responsible for any later imposed taxes or levies. Any modification of the agreement can only be made if approved by APERC.
5. Excuse and force majeure	No provision for either force majeure or excuse for failure to deliver is made. Since there is no obligation to deliver, there is no delivery obligation on the SPP.
Transmission	
1. Transmission and distribution obligations	The utility will transmit power to a remote location for the generator. Initially, a 2% wheeling charge was charged. The wheeling charge currently is 28.4%, to reflect what APTransco assesses as systemwide transmission grid losses, irrespective of the distance traveled. This is implemented by requiring the generator to put in 128.4% of the generation they transmit. In addition, the generator is charged a wheeling fee of Rs. 0.5 per kWh. As a practical matter, this has financially eliminated any generator transmission.
2. Interconnection arrangements	Interconnection is designed, installed, owned, and operated by APTransco, the costs for which are reimbursed by the SPP. However, in the case of wind developers, the developer pays Rs. 1 million per MW ($21,044 per MW). A charge of Rs. 0.10 per kWh (Rs. 0.10 per kWh) ($0.002 per kWh) is charged to handle reactive power for wind generators.
Tariff issues	
1. Type of tariff	The tariff for this nonfirm power is subject to unilateral change at any time by the state government and APERC. It was set at an energy rate of Rs. 2.25 per kWh ($0.04 per kWh), escalating at 5% per annum from the base year. As of 2003, this has increased the tariff to Rs. 3.32 per kWh ($0.06 per kWh), with future revisions in March 2003 and thereafter. APERC is considering a future SPP tariff differentiated by type of SPP technology that would apply to all existing and future SPPs. This would allow the ability to differentially promote select technologies. This is one of the highest tariffs of any of the states. APTransco claims its marginal cost of power is Rs. 2.3 per kWh ($0.042 per kWh), which understates the true cost without state subsidy. The average commercial retail tariff is in the range of Rs. 4–5.5 per kWh ($0.08–

Feature	Description of SPP feature
	0.11 per kWh). Rates for agricultural consumers are heavily cross-subsidized.
2. Capacity obligations	There is no capacity obligation and no payment for capacity. All renewable projects are nonfirm. Only for nonrenewable larger IPP PPAs, are capacity payments included in some instances. As this is a PPA for a cogeneration facility whose production varies seasonally, the amount of power delivered changes. Excess power without a capacity commitment is sold to the utility.
3. Fuel price hedging	There is no fuel price component.
4. Update mechanism	The originally set tariff is set for only the first 3 years of the 20-year term. Thereafter, APERC may review the power sale price.
5. Tariff penalties for nonperformance	There are no tariff incentives or penalties for nonperformance. The tariff mechanism is not utilized to effectuate the incentives of the agreement.
Performance obligations	
1. Operational obligations	The SPP must operate the project subject to prudent utility practices.
2. Definitions of breach	Breach is not defined in the PPA.
3. Termination opportunities	There are no provisions for termination prior to the term of the PPA.
4. Guarantees of payment and performance	If payment is made on or before the due date, the SPP receives a 1% discount and rebate credit on the next bill. If late, 14% per year interest is added.
5. Assignment or delegation	Assignment of either party must have the prior consent of the other party, which cannot be unreasonably withheld.
6. Dispute resolution	APTransco must discuss with the SPP any disputes on bills.

Tamil Nadu

The Tamil Nadu system is more than 7,000 MW. It needs surplus capacity. It can serve a daytime peak of about 6,800 MW on a typical day. About 86 percent of villages, but less than half of households, are electrified. Line losses are estimated by the Tamil Nadu Electricity Board (TNEB) to be about 16.5 percent. During evening off-peak times, it has asked biomass SPPs to back down to 90 percent of capacity. Tamil Nadu state has more than half of all of India's wind turbine capacity and a significant percentage of biomass projects.

Program Design and Implementation

1. Solicitation of SPP Participation Mechanism

Neither the government nor the Electricity Board solicit any proposals. SPPs can offer proposals and make applications. Decisions are made on a case-by-case basis.

2. Size and Resource Limitations

An SPP size limit of 50 MW is imposed. Multiple generator sets at the same location can be separately packaged into separate applications to effectively exceed this limit at the site. Also, if the power is wheeled for one's own consumption at a remote location, rather than sold to the grid, more than 50 MW is allowed.

3. Power Authority Role

The TNEB will respond to SPP proposals, but it does solicit proposals. The state has discontinued the state tax exemptions previously applied to certain renewable energy equipment. All environmental and siting approvals are the responsibility of the SPP.

4. Number and Capacity of SPP Interest and Applications

There is no limitation on the amount of SPPs that can be developed at their own initiative. It is assumed that there would be some practical limitation should there ever be a brisk development of renewables, merely to keep the system balanced between intermittent and base-loaded resources.

5. Criteria for Award

There are no quantitative criteria for evaluation. If the TNEB appraises the SPP project as viable, a PPA is executed.

6. Award Data

As of September 2002, the following awards were in place:

Energy source	*Output (MW)*
Wind	894
Bagasse	186
Other biomass	13
PV	2
Small hydro	13

7. Size and Type of Technologies

Most of the SPP projects are wind, bagasse, cogeneration, biomass gasifier, and PV. Tamil Nadu is a major locus of wind power generation. There is a wind turbine testing laboratory in the state.

8. Completion Ratio and Reasons for Failure

The TNEB claims to accept all viable projects.

9. Process Transparency

There is supposed to be an electricity regulator to deal with disputes. This position was filled only in 2002.

10. Stakeholder Concerns

Developers are concerned that third-party sales are not allowed. The risk of a single buyer is significant. The need for third-party retail sales is the paramount concern of SPP developers.

The avoided cost concept has never been implemented: Utilities often look at the cost of buying power from other state subsidized utilities as their cost, even though this is artificially depressed. These shadow subsidies make it impossible to see the true avoided cost in the market without a tariff study.

An Electricity Regulator was established only in mid-2002, and has no established track record yet in place concerning the handling of complaints or disputes. A model PPA was drafted and circulated in 2002 for possible adoption. The fact that it is a model does not mean that it is standardized for adoption. Wind generators were concerned that they were required to be certified by European labs as to capacity. There is now a testing laboratory in Tamil Nadu, and self-certification is allowed.

11. Lessons

The PPAs reviewed in both Tamil Nadu and Andhra Pradesh were the least complex of all PPAs in the five nations reviewed. This may be because it was only for the sale of surplus energy at the sole discretion of the SPP. Therefore, these PPAs outlined only the most rudimentary concepts. The rights of the parties are much less secure in these situations. Where one party is a monopoly with state sanction and is the only entity to whom power may be sold, this lack of specificity works to the disadvantage of the SPP. The PPAs in the other countries evaluated were not lengthy documents, although the addition of a few more pages makes the position of the parties much more secure where a complete contact is utilized for SPP power sale. In Tamil Nadu, about 80 percent of wind-generated power is used captively by the owners, and about 20 percent sold to TNEB.

Power Purchase Agreements

Since there are no standardized contracts in Tamil Nadu, unlike the four other countries in this comparison, there is no standardized PPA to evaluate. A model PPA has been circulated for comment, but not yet implemented or used. The model PPA is not dissimilar, although distinct from, the actual existing and executed PPA analyzed below. For the two Indian states evaluated here, PPAs for bagasse (sugar mill waste) cogeneration SPPs of approximately 20 MW are discussed.

Reasonable efforts are required of the SPP to operate during peak hours, although no express penalty exists for this failure. The model tariff would escalate 5 percent per year for the first 10 years of the contract and be subject to mutual negotiation thereafter. However, as discussed below, constraints are imposed on tariff escalation. A major problem is that the PPAs allow the utility to alter its terms or the SPP tariff at any time during the term of the contract. This is a major impediment, and SPP developers report that they execute these PPAs under protest.

This Tamil Nadu and Andhra Pradesh PPAs are the least specific and developed of those in the five countries evaluated here. These nonfirm Indian contracts are very friendly to the SPP in one sense, in that there is no performance obligation and energy can be delivered at the will of the SPP. However, the price for this is that the SPP is paid only for energy, and gets no capacity credit even if reliable capacity is provided by the SPP. This is a contract for excess energy produced by a cogeneration facility whose output varies seasonally.

The principal features of the agreements are given in table 16.

Table 16: Features of Tamil Nadu SPP PPAs

Feature	*Description of SPP feature*
Basic provisions	
1. Parties	The contract is made between the SPP and the utility, the Tamil Nadu Electricity Board ("Board"). The agreement is only for surplus power that the SPP may elect to deliver. The particular agreement reviewed ranged between 5 and 15 years. It is subject to periodic renewal or renegotiation.
2. Milestones	None.
3. Delivery of power	Delivery occurs at the interconnection point. At the end of each month, the SPP must forecast to the Board its likely deliveries during the upcoming month.
4. Output guarantees	Operation of the project is totally within the control of the SPP. Power must be accepted by the Board, except for force majeure reasons. There is no warranty to deliver any energy or capacity by the SPP. The term for biomass projects is 15 years, whereas for wind power SPPs there is no term, although the utility reports that it informally will honor these PPAs for 20 years.
5. Engineering warranties	The SPP designs and installs at its own expense its own protective equipment for parallel operation.
Sale elements	
1. Power quantity commitment	No commitment whatsoever, either for energy or capacity, or both, is made by the SPP for power sale. The utility will only purchase surplus power. In the hours between 11 p.m. and 6 a.m., the utility now requires the SPP (except for bagasse cogeneration which require the steam production) to back down some of the power sold to the grid.
2. Metering	A pair of bidirectional meters is installed, but in this case by the SPP. Check meters are then installed by the SPP. Meter accuracy is checked twice yearly; meters are calibrated yearly. Where the primary meters do not register accurately, the check meters are utilized for billing purposes. Detailed meter testing is specified.
3. Net metering or exchange	Energy banking is allowed for a 5% in-kind energy charge. The SPP is entitled to standby and backup power supply at the high-tension tariff. The SPP is allowed to wheel power over the Board's grid to its affiliated entities. When a wind project is developed, for example, a special project company can be created to be owned in shares by several companies, each of which wheels power from the wind turbine, sited to maximize wind capture, to its factory or load center. Within 25 km of it generation source, 2% is deducted for line losses; at more than 25 km, the wheeling charge is 10%. Other than this arrangement, there are no direct third-party sales currently, although it was briefly allowed in the past. Power may be sold only to the Board at the rates that they prescribe. An earlier provision to allow third-party sales was discontinued.
Risk allocation	
1. Sovereign risk and financial assurance	No provision to protect against this risk is provided.
2. Currency risk	No provision to protect against this risk is provided. In the model PPA that is circulating, the Board would provide a letter of credit from a commercial bank in favor of the SPP to serve as a surety for one month's expected power payments from the Board.
3. Commercial risk	No provision to protect against this risk is provided. Developers are required to have control of the site and a purchase order for equipment prior to signing the PPA with the

Feature	*Description of SPP feature*
	utility.
4. Regulatory risk and change of law	No provision to protect against this risk is provided. A major problem is that the PPAs allow the utility to alter its terms or the SPP tariff at any time during the term of the contract. This is a major impediment, and SPP developers report that they execute these PPAs under protest.
5. Excuse and force majeure	A relatively weak force majeure provision that includes rebellion, riot, and natural disaster, is included. In the model PPA that has circulated, the force majeure provision is somewhat stronger, including work stoppages, fire, and loss of license.
Transmission	
1. Transmission and distribution obligations	Power can be wheeled to affiliates, as discussed above.
2. Interconnection arrangements	There is no standardized interconnection agreement. Interconnection arrangements vary. Interconnection at lower voltages is designed, installed, owned, and operated by the SPP at its own cost. For higher-voltage interconnections, the SPP is required to deposit the cost of the work with the Board, which performs the work. For bagasse-fueled cogeneration, the Board bears the costs itself and performs the work. For a wind project, an interconnection charge of Rs. 15.75 lakhs per MW of installed capacity is paid by the SPP for the interconnection.[1]
Tariff issues	
1. Type of tariff	The tariff for wind was set at an energy rate of Rs. 2.7 per kWh ($0.057 per kWh), after September 2001, with no annual escalation. It is designed to remain unchanged for five years until 2006. For biomass (including bagasse), the tariff is Rs. 2.88 per kWh ($0.06 per kWh), representing an escalated base-year 2001 rate, limited not to exceed 90% of the high-tension transmission tariff (that is, Rs. 2.88 per kWh). This will escalate at 90% of the escalation of the high-tension transmission tariff. The retail tariff is state subsidized and does not recover sufficient revenue to cover costs. The retail tariff is expected to increase at a significant rate in future years. The rationale for this tariff difference is that wind is intermittent and does not supply any capacity value reliably. In addition, the wind regime in Tamil Nadu is better than the wind regime in Andhra Pradesh, and wind machines seem able to operate at the lower tariff.
2. Capacity obligations	There is no capacity obligation and no payment for capacity. Because this is a PPA for a cogeneration facility whose production varies seasonally, the amount of power delivered changes. Excess power without a capacity commitment is sold to the utility.
3. Fuel price hedging	There is no fuel price component.
4. Update mechanism	Note the PPA itself allows the utility to change the tariff or any other clause at will. In 2002, for the first time a regulator was appointed. The tariff will be periodically reviewed by the new regulator in Tamil Nadu.
5. Tariff penalties for nonperformance	There are no tariff incentives or penalties for nonperformance. The tariff mechanism is not utilized to effectuate the incentives of the agreement.

[1] One *lakh* is 100,000, such that 15.75 *lakhs* is Rs. 1,575,000 ($33,500) per megawatt [$33 per kW].

Feature	*Description of SPP feature*
Performance obligations	
1. Operational obligations	The utility reserves the right not to take power when not needed, and in the PPA the SPP agrees to back down generation during off-peak periods. Any excess above the amount of energy requested by the Board is not paid for by the Board. It does this now by requiring SPPs to back down sold power output at daily off-peak evening times.
2. Definitions of breach	Breach is not defined in the PPA.
3. Termination opportunities	Termination is allowed by the Board if any technical condition of the Board is not followed.
4. Guarantees of payment and performance	None.
5. Assignment and delegation	No contractual limitations.
6. Dispute resolution	Disputes as to power quantity or payment arise, they are referred to the government Chief Electrical Inspectorate to resolve. In the model PPA circulated, arbitration is mandatory under the Arbitration and Conciliation Act of 1996. The arbitrator's decision is final and enforceable by the courts under the laws of India. In the model PPA, all consequential and special damages are waived.

6. Sri Lanka

Program Overview

Sri Lanka is a single island nation. Unlike Indonesia, there are no multiple grids. However, unlike mainland nations, power cannot be imported or exported. Sri Lanka is a hydroelectric-based power system. By the end of the 19th century, almost 50 small hydroelectric plants operated in the country.[2]

The state utility, the Ceylon Electricity Board (CEB), maintains a monopoly on retail power sales. IPPs are allowed to own and operate power projects which sell power to CEB or consume the power for self-use. Large IPPs are able to negotiate individual PPAs with CEB.

In 1999, the national utility grid in Sri Lanka had 1,600 MW of installed generation, supplying 5,800 GWh annually. The bulk of this installed generation was large hydro projects. In the mid-1990s, consultants recruited by the government with funding from the World Bank determined a tariff structure for SPP development and a neutral PPA. This formed the backbone for SPP procurement.

A key factor in the development of SPPs in Sri Lanka is the well-integrated grid system throughout much of the island. This results historically from the distribution network reaching the plantations in the mountainous interior regions of the country. This allows the development of SPPs, even in relatively remote locations, and the transmission of power to the centralized grid and other retail users.

Program Design and Implementation

1. Solicitation of SPP Participation Mechanism

Although encouraging SPP development, the country had no formal competitive solicitation process for SPP development. The government signed some letters of intent (LoIs) with several developers who were interested in developing some of the hydro sites. Because of impediments to development, these early developers dropped away from the process. No formal solicitation process has been put forth by the government or CEB for SPPs (other than a notice in the newspapers advertising CEB's interest in purchasing power).

The CEB signs LoIs with SPP developers on an ad hoc basis. This is true even if the developer does not have site control. Traditionally, CEB made no detailed technical or financial evaluation before entering an LoI. Therefore, LoIs did not substantiate viable and feasible projects. LoIs traditionally could be obtained by speculators to block competitive development of particular sites. About 70 MW of LoIs had been executed by CEB with small power developers.

Starting in 2003, CEB amended its procedure to require a nonrefundable initial processing and application fee of Rs. 1,000 ($10), along with a prefeasibility study itemizing the hydro water resource to be utilized, and demonstrating financial capability of the SPP sponsor. CEB evaluates this application, whether another LoI has already issued for the site, CEB plans, as well as T&D system capability to absorb power input, to determine whether to issue an LoI. The LoI will only be valid for a period of six months. A performance bond of Rs. 2 million per MW ($20,661 per MW) of planned plant capacity, and a processing fee of Rs. 100,000 ($1,033) is required from the LoI recipient. Unlike prior practice, the LoI will not be transferable.

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[2] Dias Bandaranaike (2000), p. 1. Most of these delivered shaft power for tea plantations. DC power also was provided for lighting at the plantations. These provided about 10 MW.

All these reforms to the transferability, earnest money deposit, and limited duration of the LoI are reforms designed to prevent speculators without the resources to develop and finance an SPP, from tying up renewable energy sites. These are important reforms to ensure a liquid and competitive market, especially where the resource is site-specific and involves government resources, such as hydroelectric projects on government-controlled waterways. Some developers have opined that the six-month window is insufficient in which to obtain all necessary government permits and sign the required PPA, so as to prevent the LoI from lapsing. These developers suggested that it would be more appropriate for them to submit a performance bond at the time of receiving the LoI, without a six-month maximum time to sign the PPA, with the bond refundable if they did not receive all necessary government permits to enable them to execute the PPA.

2. Size and Resource Limitations

Small hydro and other renewable energy developers of facilities no larger than 10 MW, are allowed to sign a standardized PPA with CEB. The term of the PPA is up to 15 years.

3. Power Authority Role

According to stakeholders and evaluators, the process changed in the mid 1990s when the World Bank funded a consulting team to devise a standardized small power PPA and an associated tariff based on avoided cost principles, applicable to all projects up to 10 MW.[3] The standardized PPA eliminates market uncertainty and along with a methodology to determine the avoided cost of CEB, facilitated the development of the small power sector.[4] In addition, the World Bank provided International Development Agency (IDA) funds to the government to facilitate commercial and development banks to lend on longer terms at conventional rates to SPP developers. Asian Development Bank funds also were made available to develop the plantation sector of the economy, and could also benefit plantation SPPs. These multilateral Bank funds have found their way to Sri Lanka commercial banks that are lending to the SPP projects going forward. SPPs have been project-financed with these funds.

Where developers invest more than $750,000 , they are allowed to import equipment duty-free and pay a concessionary corporate income tax rate of 15 percent annually for seven years. Where total investment exceeds $7.5 million, complete tax exemption is given for 10 years. The Central Environmental Authority must approve each project, the regional government authority must approve use of water from the stream to generate power, and the chief electrical inspector must license the generation and sale of power.

4. Number and Capacity of SPP Interest and Applications

Data were not available on number of LoI applications. A substantial small hydro capacity exists in Sri Lanka. One authority estimates this as 250–300 MW at sites where facilities of up to 10 MW could be developed, plus an additional 200–250 MW at sites where 10–25 MW facilities could be developed.[5] This adds up to about 500 MW of financially viable small power hydro sites. However, CEB estimates this as a much smaller potential, and nothing approaching this potential is under active development.

[3] Dias Bandaranaike (2000), p. 4.
[4] Dias Bandaranaike (2000).
[5] Dias Bandaranaike (2000), p. 3.

5. Criteria for Award

Contracts have been awarded by CEB without a formal solicitation process based on viability.

6. Award Data

Initially, with the assistance of a nongovernmental organization (NGO), two small existing electric facilities serving plantations were connected to the grid. This involved moderate additional expense, since the facility already existed, and demonstrated an initial CEB-SPP relationship. An 800 kW greenfield project followed suit. All of these projects were hydroelectric technology. The first project under the new initiative connected in 1997. In total, by the end of 2002, 13 SPPs with 43.3 MW had interconnected to CEB. This represented about 2.5 percent of electric power production capacity in the grid.

7. Size and Type of Technologies

All of the awarded projects were small hydroelectric project with the single exception of one small cogeneration facility.

8. Completion Ratio and Reasons for Failure

A completion ration cannot be calculated because precise data on applications is not available. As of 2002, about 43 MW of SPPs were grid connected and generating power. About 20 additional MW were under construction, involving many of the same developers. Financing was provided with World Bank funds through the Energy Services Delivery project and later by the Renewable Energy for Rural Economic Development Project. There were approximately 200 MW of potential projects at 55 sites that received LoIs, with applications for another approximately 60 MW at about 40 sites having been filed. The amount of projects actually completed was a small fraction of those that sought approval to develop.

There is no formal government policy to promote SPP development. The price paid for power is not based on any capacity payment. Only an energy component is paid—and this value fluctuates annually. Thus, there is no long-term certainty for the tariff.

9. Process Transparency

The lack of a formal program has discouraged some early interest from international developers, who also were frustrated from navigating all the intricacies of the siting and approval process. At least one stakeholder reports that the ongoing unilateral changes in the tariff undercut confidence of some of the SPP developers and eliminated from consideration technologies other than small hydro SPPs. Nevertheless, domestic developers appear to have mastered the process. The 2003 requirement of a monetary deposit for limited duration of and nontransferability of LoIs will create a process to screen speculation from the SPP program.

10. Stakeholder Concerns

Prior to the introduction of the standard PPA and tariff and provision of loan funds by the World Bank, there were major impediments to financing SPPs. The local banks worked with relatively short-term deposits, and did not have experience with credit facilities to project finance SPPs. Therefore, debt capital was not available in sufficient quantity or for sufficient term to finance SPP development.

There was international interest in Sri Lanka hydropower prior to the World Bank program in that country when the government made several large hydro sites available. Several foreign developers have dropped out of project development from frustration. This has benefited domestic developers, who also have some cost advantages on small projects. There has been a dispute between developers and CEB regarding the annual process for tariff update. Stakeholders have complained in the past that the tariff does not provide a capacity value, and does not fully provide for avoided energy cost. There seems to be less acrimony now about the annual tariff update process, although it is still not set out in an objective formula.

11. Lessons

Even where profitable renewable energy SPP sites exist, a standardized PPA and a predictable purchase rate, along with private sector financing, are essential elements of a successful PPA program. The 2003 reforms in the LoI process for SPPs seem to be positive. They should discourage lone speculators who do not have the experience or credit to support actual project development. This should improve the efficiency of SPP project development by prequalifying SPP developers and eliminating indefinite hoarding of the LoI rights to the best hydro sites.

Power Purchase Agreements

The principal features of the agreements are given in table 17.

Table 17: Features of Sri Lanka SPP PPAs

Feature	*Description of SPP feature*
Basic provisions	
1. Parties	The contract is made directly between the state utility, CEB, and the SPP. As a body corporate, CEB waives the sovereign immunity it otherwise could assert against legal action.
2. Milestones	The SPP contract contains negotiable date milestones for (a) achievement of all necessary permits for land acquisition, construction and operation, and (b) achievement of commercial operation. The SPP is responsible for obtaining all permits.
3. Delivery of power	CEB must accept all power at the delivery point as long as operated pursuant to Good Utility Practices and the facility maintains its eligibility for SPP status by selling (not necessarily installing) no more than 10 MW, unless the CEB system is not able to accept power. The contract is only for the transaction in energy, not energy capacity.
4. Output guarantees	The SPP maintains control over the amount of energy sold, with the SPP designated as a "must run" facility, whereby CEB is obligated to take and pay for the energy tendered, unless there is an emergency in the CEB system. There are no consequential damages for which the SPP seller is liable, unless it diverts energy or heat to purposes other than sale of pledged output to CEB. If the facility is capable of generation, it must generate and deliver power to CEB. It may not divert power to other buyers. It may cease to generate only where there is a valid engineering reason for such interruption, and is obligated to provide at least 24 hours notice of interruption when possible.
5. Engineering warranties	Power must be delivered pursuant to IEC standards. The quality of the electric energy output delivered at the termination point is individually defined as to voltage, power rating, power factor, maximum line current and power, and frequency. Delivery voltage is 33 kV plus or minus 10%.
Sale elements	
1. Power quantity	The output capabilities of the SPP are stated in the PPA. The SPP may sell no more than 10

Feature	*Description of SPP feature*
commitment	MW of equivalent energy output under the contract. It is not prohibited for the SPP to install greater capacity than is sold to CEB.
2. Metering	CEB owns and maintains the metering equipment. Either CEB or independent third-party calibration is allowed by contract, however, the contract does not specify how the parties choose from among these two alternatives. The meters are required to operate subject to IEC standards. Meters are tested annually and require accuracy within 2%. In the interim period, the SPP can request a test if it believes that the meters are not registering accurately, but regardless of the outcome, the SPP pays for such test. There is established a hierarchy of which set of multiple meters is employed to measure the energy sold during each billing period, cascading to secondary metering sources when the primary metering is not within accuracy parameters, and assuming that the secondary meters are operating accurately. If not accurate at the secondary level of metering, historic data from the prior year is utilized, adjusted by rainfall, stream flow, fuel consumption, heat rate, hours of operation, native self-use, and other factors, to estimate output. If this data is not available, data from the prior six months is used as an average proxy of the amount of output sold.
3. Net metering or exchange	Not contemplated by the contract nor allowed by the program.
Risk allocation	
1. Sovereign risk and financial assurance	By contract, sovereign immunity is waived by CEB, as a body corporate, as a defense to suit.
2. Currency risk	The tariff is paid in local rupees on a kWh-delivered basis. There is no indexation to foreign currencies. Therefore, borrowing in local currencies is necessary to protect against currency fluctuations affecting repayment options.
3. Commercial risk	All commercial risk is absorbed by the SPP. The obligation to attempt to produce and deliver, and for the utility to take and pay for, energy, is absolute except for short justifiable interruptions on either side of the transaction. The term may be up to a 15-year term.
4. Regulatory risk and change of law	Although there originally was a change of law clause covering regulatory and tax changes to facilitate a consequent adjustment of the price term, as suggested by the legal consultants, that clause was later not carried forward in the final PPA by the utility. Such risk is now borne by the SPP. The price paid for power is not based on any capacity payment. Only an energy component is paid, and this value fluctuates annually. Thus, there is no long-term certainty for the tariff, which impedes financing.
5. Excuse and force majeure	Force majeure is provided for both acts of God and for more controllable acts. Force majeure is defined in a manner conventional for power sale agreements, including civil disturbance and failure of the sovereign to grant necessary permits. Failure to obtain necessary fossil fuel from a supplier for the SPP, or any other cause out of a party's control, is also deemed to be a force majeure event. The time limit for the maximum duration of a force majeure event is three years. After three years, if not cured, the other innocent party may elect to terminate after an additional notice of 90 days. This is at the most liberal allowance of the range of U.S. small power contracts surveyed by this author. This provides more flexibility to attract small power producers.
Transmission	
1. Transmission	The SPP must deliver the power at its own cost to the delivery point, which is the line side

Feature	Description of SPP feature
and distribution obligations	of the isolator on the CEB grid, and pay for all interconnection and protective costs, as well as all interconnection costs up to the termination point. The title to energy passes at the metering point. CEB must use "best efforts" to take the power or to minimize any disruption given the "must run" status of the SPP. Since CEB is the only entity to whom the SPP may sell power, other than its host or otherwise allowed by license, there is no obligation of the utility to transmit power. Long delays and bottlenecks have been reported by one stakeholder, although it is not clear whether this is a persistent or isolated issue.[6] CEB requires that it build the interconnection or an entity approved by CEB build the line to CEB design standards using materials purchased from CEB.[7]
2. Interconnection arrangements	Interconnection standards are governed by Interconnection Guideline G. 59/1 of the British Electricity Association. Either the utility can build and bill the SPP for the interconnection upgrades and equipment, or the SPP can construct the interconnection equipment pursuant to utility review and standards, and then dedicate such facilities to the utility. In either event, the SPP incurs the entire cost of the protective equipment. If upgrades, repairs or modifications are later required by the utility, the SPP must implement same at its own expense.
Tariff issues	
1. Type of tariff	The tariff is based on avoided cost principles. CEB defines its avoided costs as the maximum value of additional generation that it avoids. Even where Sri Lanka requires capacity and these projects effectively provide long-term capacity, and the PPAs are set up to provide "firm" power, CEB pays only an energy value for the power. The contract includes the marginal cost of fuel and variable O&M in this value. The marginal fuel cost is the cost of petroleum to CEB from the state Petroleum Corporation. Allowances of a total of 7.7% are made for station and transmission losses and CEB overheads. The tariff is the average of (a) the prospective energy avoided cost calculation and (b) the calculation utilized during the prior two years. Although initially recommended to calculate a three-year forward average of avoided cost, CEB elected to calculate a three-year backward average of avoided cost. Even for energy, this would have exceeded 6 cents per kWh in 2003, according to an independent consultant report in 2001. Because these tariffs would exceed those paid to IPPs, CEB elected not to pay full energy avoided cost to SPPs which are not dispatchable. The price for energy is seasonally adjusted; that is, it is reestablished annually by each December 1 for the ensuing calendar year. The "Dry Season" comprises February through April, and the "Wet Season" comprises May through January. These variations during each year are set forth in table 18.
2. Capacity	The SPPs were originally told that they would be paid a flat price of 6 cents per kWh,

[6] Dias Bandaranaike (2000), p. 7.

[7] Dias Bandaranaike (2000). In one instance, this author relates the story of a particular instance of CEB delay of four months in providing the design, CEB requiring 100 percent up-front payment by the developer, then failing to supply all of the required materials and refusing to allow the SPP developer to purchaser the mis sing parts for CEB's supplier, but instead requiring the SPP to wait until CEB next got around to ordering parts. The SPP developer claims it was required to pick up the 1,000 necessary parts from a CEB yard, with no guidance as to where the parts were located in the yard. That author reports that it required 36 person-days for the developer's personnel to locate all of the parts in the CEB yard. Dias Bandaranaike (2000), p. 8. There is no indication whether this was an isolated incident.

Feature	*Description of SPP feature*
obligations	escalated during the term of the contract. This was later changed by CEB with payments to be set annually at the short-term avoided cost of CEB, with diesel fuel typically the fuel at the margin. CEB does not pay an avoided capacity component even for a long-term PPA that provides capacity value, even where the CEB system needs capacity. The energy component fluctuates annually, providing no long-term certainty for the tariff.
3. Fuel price hedging	The projects built under the SPP program to date in Sri Lanka are small hydroelectric projects. There is no fuel hedging for such projects.
4. Update mechanism	Energy prices are updated annually by December 1 to apply for the prospective year. The price is seasonally adjusted within each payment year. Energy prices may not decline below 90% of the price applying at the time of the execution of the contract. This was done to establish a floor underneath renewable energy prices so as to facilitate their financing.
5. Tariff penalties for nonperformance	Late payments bear interest at the prime rate then in effect.
Performance obligations	
1. Operational obligations	The SPP must use its best efforts to deliver power. However, failure to deliver power for short periods, while justifying damages to the purchaser, does not rise to the level of a cause for termination. Provided in this contract are requirements for the SPP annually to forecast the amount of power to be produced and sold, with a minimum one month notice of planned outages, and the right of CEB to have access to and inspect the SPP facility.
2. Definitions of breach	Typical commercial definitions are employed. Failure to achieve milestones, failure to pay for 90 days, or bankruptcy of the SPP constitutes a breach. There are no express remedies provided for breach and no explicit penalties in this contract. There are no consequential damages. No deposits or other security are required of the independent producer. Breaches must be cured as soon as possible. A party has 60 days after notice to cure a breach without it constituting a default; or if it requires longer, such cure must be begun within 60 days and the cure accomplished within no more than two years.
3. Termination opportunities	Termination may not be made at the sole election of either party without cause, but may be made 30 days after default, which is defined in the agreement as an uncured breach that ripens into an event of default. Cause for termination includes only uncured default, uncured nonpayment, or uncured force majeure. The project lender gets an opportunity to cure any default. This is an important element for project finance in providing additional loan security to project lenders.
4. Guarantees of payment and performance	The Agreement contains no guarantees of any performance obligations.
5. Assignment and delegation	Other than to subsidiaries for the purposes of financing or to hold the project in a project company, the SPP may not assign or delegate its rights without the prior written consent of CEB, which may not be unreasonably withheld. A succession clause is included which has any successor of either party assume all duties. There is no restriction on assignment by CEB.

Feature	Description of SPP feature
6. Dispute resolution	The parties first pledge to attempt to informally settle any dispute among themselves during a period of 30 days. If not settled, and the sum in dispute is less than SL Rs. 1 million, the parties may agree to appoint a single neutral party to resolve the dispute or may ask the government to appoint an expert in the field to resolve the dispute, in either case to resolve the dispute within an additional 60 days. If not then resolved within 90 days, either party may refer the dispute to arbitration under the Arbitration Act No. 11 of 1995.

Table 18: Annual Season SPP Tariff in Sri Lanka

	Dry season purchase price (in current terms)		*Wet season purchase price (in current terms)*	
Year	*Rs. per kWh*	*$ per kWh*	*Rs. per kWh*	*$ per kWh*
1997	3.380	0.068	2.890	0.058
1998	3.510	0.062	3.140	0.055
1999	3.220	0.047	2.740	0.040
2000	3.110	0.043	2.760	0.038
2001	4.200	0.051	4.000	0.048
2002	5.130	0.053	4.910	0.051
2002	5.500	0.057	5.650	0.059
2003	6.060	0.062	5.850	0.060

Source: Ceylon Electricity Board.

Even though the price at which CEB will purchase power was raised by more than 75 percent in local currency between year 2000 and 2002, this increase is offset by a decline of the rupee against the dollar in the same period of 33 percent. This makes the net increase in the SPP power sale price in dollars equal to slightly more than 40 percent—still substantial. During the life of this program, the price for power has fluctuated between $0.043 and 0.06 per kWh, depending on the increase in SPP price against the depreciation of the Sri Lanka currency against the U.S. dollar.

7. Vietnam

Program Overview

Vietnam is a nation that is embarking on independent power development in 2000, and that has a shorter track record than some of the other Asian countries reviewed herein. Vietnam has many elements in common with regard to renewable energy and small power potential with some of its Asian neighbors. Like Sri Lanka, it is a hydroelectric-based system. Like Indonesia and Thailand, it has local access to petroleum and natural gas hydrocarbons to generate fossil fuel–based conventional energy. Like Indonesia, Sri Lanka, and India, the need for new investment in additional power generation capacity outstrips the available internal capital resources. Therefore, attraction of additional private investment capital is very important.

Unlike Indonesia, Vietnam is not a fragmented island system of distinct grids. There is a central transmission spine running the length of the country, that allows a grid-connected system through much of the nation. About 86 percent of local communes have access to electricity; the plan of the Ministry of Industry is to have 90 percent electrified by 2005.[8]

Electricity of Vietnam (EVN), the state utility, has a system that had about 6,500 MW installed as of 2002. Growth was projected at about 15 percent annually. Electricity demand peaks in the evening hours, as well as during the dry season when the predominantly hydroelectric capacity of the EVN system has fewer supply resources upon which to draw.[9] Vietnam, by implementing its SPP program a few years later than the other countries discussed, has the opportunity to analyze what has worked best in other systems, and why, and can benefit from the experience of these other Asian countries in designing and implementing its own SPP programs.

[8] The system produces about 35 million kWh annually, and plans to generate 53 million kWh annually with 11,000 MW available by 2005. The growth projection will require the investment of $1.5–2 billion annually in the electric sector of the economy. EVN owns about 90 percent of the generating resources. The goal is to have the proportion of IPPs and SPPs increase over time; because of the private capital that will accompany them (personal interview with EVN, Vietnam Ministry of Industry, and World Bank officials (2002)).

[9] The dry season runs from December through May (Worley International 2000).

Program Design and Implementation

The SPP program in Vietnam is not yet designed or implemented. As this report is finalized, Vietnam is engaging in final program design. The analysis that follows focuses on earlier program planning.

1. Solicitation of SPP Participation

The program in Vietnam is in the development stage. A draft SPP PPA was created by a consultant and accompanied by a tariff design in 2000.[1] Since then, the final format of the PPA and the tariff have not been agreed to by the stakeholders, and no formal SPP program has begun. In the interim, EVN has entertained IPP projects on a less structured basis.

Although patterned on the Sri Lanka SPP PPA, the year 2000 draft consultant PPA employs a different tariff concept than the PPAs employed in Indonesia, Sri Lanka, and Thailand.[2] These latter three countries employed a U.S.-type PPA adapted from the U.S. PURPA experience. The Vietnamese draft employs the concept of "deemed energy."[3] This concept typically is not employed in SPP PPAs, to create a simpler format. Such a two-level or "split" PPA tariff is typical of larger fossil-fired baseload facilities, and is less used for often intermittent, smaller renewable energy facilities. This distinction is in part a reflection of EVN desire to control operation of IPPs in the country as a condition of power purchase, and in part a function of the consultant's recommendations. No final decisions have been made on the draft PPA and tariff design.

2. Size and Resource Limitations

EVN is just at the start of its IPP and SPP program, and to date has not made a distinction between the two. It has committed to three IPPs, all of which are large fossil fuel–fired facilities. At a workshop in December 2002, EVN committed to an SPP program based on avoided cost principles.[4]

EVN envisions an affordable price for energy to be about $0.045 maximum in the dry season, and about $0.025 in the wet season. This is limited by EVN wanting not to pay more for energy at wholesale than it can sell energy for at state-approved retail rates, allowing the necessary retail mark-up of $0.016–0.018 for transmission charges. Therefore, although committing to the principle of avoided cost pricing, EVN feels limited by the pressure not to lose money under a system that is not operated to break even, but rather in significant part is operated to advance the social policy of distributing electricity at rates that knowingly do not cover all revenue requirements.[5]

[1] Worley International (2000).
[2] Worley International (2000), p. 4.9.
[3] Worley International (2000), appendix A.
[4] Ministry of Industry (2002).
[5] EVN is committed to the principle of avoided cost payments, as long as they do not exceed its average retail tariff, less transmission expenses (personal interview with EVN (2002)). Avoided cost, is a marginal, rather than average cost, concept. EVN also wants operational control of the plant, which could raise conflict on cost recovery issues, as the tariff is only paid on kWh sold, and failure to dispatch the plant would result in less revenue, unless a split tariff were employed to assure that the capacity costs of the plant were repaid by a fixed, nonvariable tariff component.

3. Power Authority and Government Role

Vietnam is a socialist country. This dictates that the economy—including the electric sector—is centrally planned. Therefore, factories are located by the central state planning authority in a location that takes advantage of existing and planned electric generation and transmission capacity.[6] This fact distinguishes it significantly from other Asian nations reviewed herein, where the geography or lack of central planning causes industrial load centers to be located in disparate pockets of the country.

Enterprises are typically owned and operated by the state. The capital allocation process is different for these companies in that they do not account for profit and return in the same manner as a publicly traded private company. They are dependent upon various levels of state approval for their access to capital and authorization for investment. The approval process for projects in Vietnam is lengthy, involving multiple ministry approvals.[7] These include submittal of SPP plans through a prefeasibility study, investment approval, establishment of a domestic or foreign investment activity, feasibility study approval, negotiation of a PPA and an interconnection agreement, and construction approval.

4. Number and Capacity of SPP Interest and Applications

There were approximately 67 proposed renewable energy SPP and IPP projects in Vietnam as of the end of 2002.[8] All are still in the development stage, with most lacking a signed PPA with EVN. All these projects are from state-sponsored entities, people's committee, or communes, with the exception of one private 3.6 MW hydro proposal. Some of the state projects may attempt to sell shares to private investors.

5. Criteria for Award

No criteria are established for awards implemented by EVN, because the SPP program is still in the development stage. There are a variety of ad hoc criteria applied by EVN. The project must have completed its prefeasibility study prior to contract with EVN.

6. Award Data

Only three large fossil fuel–fired IPPs have to date executed contracts with EVN. Vietnam has entered its first larger IPP projects with two international companies to construct large combined cycle gas-fired machines of approximately 350 MW each. These projects involve indexation of payments. These contracts pay the developers approximately \$0.04 per kWh, which approximates the avoided cost of the utility, EVN.[9] The average retail service tariff is \$0.056 per kWh.[10] All amounts paid to the smaller IPP

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[6] Personal interview with EVN, Vietnam Ministry of Industry, and World Bank officials (2002).

[7] Required sequentially before a project goes forward is a prefeasibility study and approval, a memorandum of understanding with the utility, EVN as to power purchase which is now negotiated on an ad hoc basis, a feasibility study with approval and "stamps" from various ministries, establishment of a business entity for the project, a construction permit, and special approval for foreign investment. For more information about the approval process, see Worley International (2000), Section 2.

[8] Project list of EVN (2002). These projects are proposed by 13 state enterprises, municipalities, or communes, plus one private developer.

[9] British Petroleum and Electricité de France are venture partners in these two projects. The price escalates annually for natural gas cost increases of about 2.5 percent annually. One existing diesel project IPP of about 375 MW, receiving a purchase price of about \$0.056, already exists (personal interview with EVN (2002)).

and SPP projects are paid in local currency, with no indexation for foreign exchange. These small projects also do not benefit from international agency guarantees.[11]

It has yet to finalize an SPP program or SPP awards, although several projects are in the prefeasibility or feasibility approval stage of project development. Some of the various other IPP and SPP projects are now discussing final PPA terms with EVN.

7. Size and Type of Technologies

As noted above, two gas-fired IPPs at about 350 MW each and one diesel oil IPP of about 300 MW have executed contracts. Most of the pending proposals awaiting decision are hydroelectric and of intermediate size ranging from 10 to 115 MW, although there are proposals for a 15 MW wind project, as well as discussion about biogas from landfills. More than half these proposals would be considered intermediate IPP-size projects. EVN reports that almost half the inquiries would be smaller (predominantly hydroelectric) projects of 30 MW or less. There are existing sugar mills, municipal waste, landfill gas, glass companies, shoe and apparel manufacturers, cement facilities, and rice processors that could be the site of cogeneration SPPs.[12]

8. Completion Ratio and Reasons for Failure

The SPP program does not yet have enough experience to know the success-to-failure ratio. Interviews with stakeholders in Vietnam indicates that lack of access to public or private capital is a major impediment. Also mentioned was lack of a neutral standardized PPA (EVN is negotiating a PPA in each circumstance) and lack of a standardized SPP tariff. Also mentioned was lack of a standardized interconnection policy. The process for project approval through the various state ministries also was mentioned as a lengthy impediment that could be streamlined.

The currency has been relatively stable compared to some other Southeast nations. This is because the Vietnamese dong is subject to a managed float against the U.S. dollar.[13]

9. Process Transparency

SPPs are now required to individually negotiate with EVN. The approval process for projects is long and complex. Stakeholders in Vietnam have asked for more SPP project transparency in the form of a standardized neutral PPA incorporating a standardized SPP tariff, along with a standardized interconnection-operation policy. In December 2002, EVN committed to such a process.

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[10] The rates were raised in October 2002. It is expected that the tariff will continue to be raised in successive years. There is cross-subsidy in the tariff: Large users cross-subsidize smaller users and rural consumers benefit from cross-subsidy, as part of the tariff policy of the government (personal interview with EVN, Vietnam Ministry of Industry, and World Bank officials (2002)).

[11] Personal interview with EVN, Vietnam Ministry of Industry, and World Bank officials (2002).

[12] One of the sugar mills has a two-year agreement at about $0.037 per kWh to sell excess energy to EVN (personal interview with EVN, Vietnam Ministry of Industry, and World Bank officials (2002)).

[13] The dong depreciates about 5 percent per year against the U.S. dollar in a managed float (personal interview with EVN, Vietnam Ministry of Industry, and World Bank officials (2002)).

10. Stakeholder Concerns

The state-owned developers have many of the same concerns that private SPP developers have in other nations:[14]

- The approval process is slow and cumbersome.
- The feasibility study approval requires a lender commitment, but that is very difficult to obtain prior to having a PPA from EVN.
- Difficulties exist with the interconnection procedure, which is not standardized and not dealt with in the PPA.
- Consistency is lacking in the PPA and in setting a tariff based on a cost principle.
- Accessing capital is difficult from local banks that have high interest rates and that will often not lend for a sufficiently long period; EVN receives a lower cost of capital than SPP developers.
- EVN is unwilling to front-load the payment of the power revenue stream to correspond to the higher first-costs of renewable power investments.
- EVN has a tendency to pay lesser amounts for power where it believes that the SPP sponsor is receiving a higher-than-necessary return on investment, instead of enforcing an avoided cost or other consistent pricing principle.
- There is a lack of transparency in the negotiating process for PPAs and tariffs.
- The local state developers lack development experience.

11. Lessons

Even in a socialist government structure, a standardized neutral PPA incorporating a standardized PPA tariff has great value and is a necessary for successful SPP program implementation and administration. Without such a standardized program, resources are expended unnecessarily and inefficiently. It is in the interest of any nation that needs additional electric capacity to most efficiently mobilize SPP and renewable energy resources. Experience in Vietnam indicates that it is not fundamentally different in a socialist economy. When the objective is to mobilize private capital, a standardized SPP PPA is the most efficient and cost-effective, as well as transparent, mechanism.

Power Purchase Agreements

In 2000 a consultant drafted a PPA for possible adoption by EVN. EVN has not yet adopted this draft PPA and likely will utilize a PPA of its own design when it does commit to a standardized SPP PPA. Like the agreements before it in Indonesia, Sri Lanka, and Thailand, the draft year 2000 PPA is a tight and concise PPA appropriate for an SPP renewable energy project. It was drafted by the consultant after reviewing the Indonesian, Sri Lankan, and Thai PPAs, and is expressly modeled on those—especially the Sri Lanka—PPAs.[15] However, it is different in important ways compared to the PPA utilized in Indonesia, Sri Lanka, and Thailand. In particular, it leaves some terms less precisely defined and utilizes a "deemed energy" concept to pay the SPP for capacity even when the utility does not take power. Even though not

[14] Ministry of Industry (2002) seminar on Power Purchase Agreements, at which the author was a featured participant.
[15] Worley International (2000), section 4.2.

yet implemented, this format is a contrast to those in the other contracts mentioned herein. The contracting provisions in the draft PPA for Vietnam, and how they operate, are discussed below.

The principal features of the agreements are given in table 19.

Table 19: Features of Vietnam SPP PPAs

Feature	*Description of SPP feature*
Basic provisions	
1. Parties	The contract is made directly between the SPP and the state utility, EVN. As structured, no lender rights are expressly recognized, as they are in the Indonesian PPA. Parties are allowed to sign the contract in two different languages simultaneously. No matter how proficient the translation, there will be significant differences and nuances that can change the interpretation. Ideally, there should be a single executed PPA for each project: The parties should execute only one contract, in either Vietnamese or English, typically at the election of the SPP so that it can utilize the language that facilitates project debt financing.
2. Milestones	A milestone for commercial operation is contained in the PPA, but its length of time is not specified. It is individually negotiated.
3. Delivery of power	EVN must purchase all power supplied by the SPP. No delivery requirement is imposed if there is a forced outage. EVN has indicated that it is willing to purchase all excess power if it has operational control over the SPP. This interface and control will need to be carefully structured during final negotiations on a standardized PPA.
4. Output guarantees	The PPA allows the utility purchaser not to accept or pay for power where SPP facility maintenance is inadequate, but it does not affect the quality of the energy. This allows the purchaser not to pay for deemed energy output, and could mask Transmission and distribution (T&D) problems. This could discourage lenders not to participate in this program.
5. Engineering warranties	The SPP must be operated pursuant to Prudent Utility Practices, which are conventionally defined, in a manner similar to the commonly employed concept of "Good Utility Practices."
Sale elements	
1. Power quantity commitment	The agreement does not require the SPP to use best efforts to produce power (capacity) or EVN to accommodate and take power. There is no typical reciprocal obligation for the buy-sell transaction, where EVN must take, the SPP must produce and deliver. EVN can refuse to take power for any system-related reason. Otherwise, if it refused to take power, it must pay for deemed energy output.
2. Metering	The meters are maintained by EVN at the SPP's expense. The meters are calibrated at least every 12 months, with +/- 2% accuracy required. Secondary meters, installed at the expense of the SPP, are used to register quantity if the primary meters are not accurate; and if the secondary meters are not operable, estimation is done without any specific legal references for this estimation. So, this places the SPP at a disadvantage. There is no time limit on subsequent adjustment. There is a requirement that if one party thinks there is meter inaccuracy, the meters must be tested. The metering provision requires that both parties "shall" be present to break meter seals.
3. Net metering or exchange	There is no provision for net metering and no direct sale at retail is allowed the SPP.
Risk allocation	
1. Sovereign risk and financial	Nationalization or expropriation of the SPP assets by the government is deemed an event of default by EVN. However, the remedy for such is not clearly specified and could be difficult

Feature	*Description of SPP feature*
assurance	to enforce in any Vietnamese tribunal. After notice of default, the defaulting party has 60 days, plus an extension of another 30 days, to cure the default before it terminates the agreement.
2. Currency risk	SPPs would be paid in Vietnamese dong, so there would be no protection for currency fluctuations. The dong is subject to a fixed exchange and has been relatively stable.
3. Commercial risk	Commercial risk under the contract is borne by the SPP. The types of insurance required of the SPP are specified by contract without specifying the amount of coverage, any requirement to name the buyer as an additional insured, or any other requirements.
4. Regulatory risk and change of law	There is no provision on this risk.
5. Excuse and force majeure	"Force majeure" is defined as any third-party or extraneous action that interrupts performance. This would include failures of supplies, fuel, or T&D capacity. "Forced outages" are defined only to include investigations, repairs, and replacement. Force majeure does not include failure to comply with EVN interconnection or grid standards or failure of a supplier to perform. Under the draft PPA, if something is wrong with the T&D system or repairs are necessary, then EVN pays for power it does not receive and gains no revenue because it cannot resell. However, if there is a force majeure event affecting EVN, there is no payment for this phantom energy. However, there is not a clear delineation between these two kinds of events in the draft PPA.
Transmission	
1. Transmission and distribution obligations	Since there is no ability to wheel retail power or to make third-party sales, wheeling obligations of the utility to not arise. At the interconnection delivery point, the power becomes the property of EVN.
2. Interconnection arrangements	Interconnection is designed and constructed by EVN. These costs are billed to the SPP. SPPs are concerned about a lack of standardized interconnection procedure.
Tariff issues	
1. Type of tariff	There is no standardized SPP tariff. The SPP power purchase price is negotiated on a case-by-case basis by EVN. EVN negotiates this tariff to attempt to not lose money on its retail resale of IPP and SPP power. Therefore, it subtracts from the average retail tariff its average transmission and distribution charges, yielding a residual value for the maximum SPP price. This methodology (a) utilizes average system cost concepts and (b) is limited by state-set retail tariffs for a system that does not earn revenues to cover its fully loaded costs. The avoided cost concept of SPP program design is predicated on marginal costs. Therefore, this tariff mechanism is not based on avoided costs at the present time in Vietnam.
2. Capacity obligations	The consultant in year 2000 recommended a dry and wet season tariff, with a $0.013 per kWh "minimum supply bonus" for SPPs that commit and deliver at least 70% of their capacity in a given month. This deemed energy concept is a concept that typically is associated with payment for capacity regardless of delivered energy. Every minor problem with EVN acceptance results in payment for output that cannot be taken. These types of tariffs and contracts typically are for large baseload fossil-fueled projects. Their adaptability to small renewable projects is not yet demonstrated in Vietnam.
3. Fuel price	There is no fuel price hedging.

Feature	*Description of SPP feature*
hedging	
4. Update mechanism	There currently is no update mechanism. The retail tariff is expected by EVN to escalate to as much as $0.07 per kWh by about 2005. This could allow more flexibility for EVN to pay a higher cost for SPP power over time.
5. Tariff penalties for nonperformance	The tariff is not structured to encourage economical production and delivery of power on peak because the capacity payments are not loaded into the delivered power price. The contract implies that the project is dispatchable; however, this contract does not otherwise provide dispatch control to EVN. For small renewable projects, dispatch is not an ordinary operating paradigm.
Performance obligations	
1. Operational obligations	The agreement does not require the SPP to use best efforts to produce power (or commit capacity) or EVN to accommodate and take power. There typically would be a reciprocal obligation—EVN must take, the SPP must produce and deliver. Where there are no penalties for nondelivery imposed on the SPP, there typically would be more flexibility for EVN acceptance. EVN can refuse to take power for any system-related reason. Otherwise, if it refused to take power, it must pay for deemed energy output.
2. Definitions of breach	Default occurs if permits cannot be obtained by the SPP. This failure, or an improper assignment or failure to carry insurance, could result in a default whether or not it would be deemed a material breach otherwise. Typically, only for *material* breaches are damages (but not default and cancellation) the appropriate remedy. Cancellation is not a particularly effective remedy for the SPP under certain default scenarios because there is no allowed net metering or other retail or wholesale power sale opportunity.
3. Termination opportunities	The draft contract provides that even if it is the SPP that terminates the agreement because of a default by EVN, that EVN has purchase rights to the SPP facility at fair market value. This option becomes mandatory under certain termination conditions. This allows a one-sided buy-out provision. It is not specified whether the buy-out price at the time of termination is calculated to reflect the fact that the project is in default and therefore no longer viable. EVN is provided an opportunity to extend the term of the agreement for a contracted period of years at the specified termination of the agreement.
4. Guarantees of payment and performance	There are no sovereign or other guarantees of performance by the utility. In a socialist economy, both the seller and purchaser of power are state entities.
5. Assignment and delegation	Any assignment requires the prior written consent of the other party, which shall not be unreasonably withheld. Without consent the SPP can assign to an affiliate or for the purposes of financing the facility.
6. Dispute resolution	If a dispute ensues, the parties shall try to settle the dispute informally for 30 days. If not resolved, the dispute is submitted to arbitration. The place of arbitration and the rules under which resolution is pursued are left blank for the parties to complete. Either party has the ability to cut off the other party's court rights by making a unilateral referral to the arbitrator.

8. CONCLUSION

It is clear, in an era of robustly increasing demand for electric service, supply, and reliability in Asia, amid tight capital availability, that in most nations renewable energy projects and private capacity additions will have a premium value. Renewable projects avoid vulnerability to conventional fuel unavailability and price fluctuations, and continue to draw from a naturally renewed and essentially costless energy input to electric generation. The renewable option is available in abundance in Asia. Every nation in the world has enough solar energy falling on either its roads or buildings to supply 100 percent of its electric requirements.

The challenge is to most cost-efficiently develop these resources. Private SPP investments in electric sector–generating assets accomplishes needed and planned electric sector development without obligating additional state resources. The recent trend of increasing private SPP development will accelerate in the 21st century.

As some of these SPP programs have proved themselves, the project development environment has changed significantly. International investment has become more cautious. The general economic slow-down, coupled with negative performance of international investments in IPP and TRANSCO systems, have made many international developers hesitant to assume as much risk as in past investments with new private IPP or SPP investments. Many are liquidating their international power investments. In addition, with nonperforming generating assets, wholesale power markets in many developed and developing nations have become illiquid. Equity investment and debt financing have become more problematic and conservatively oriented. Disagreements between IPP developers and utilities over PPA enforcement in several Asian and other nations have compromised investor confidence. Even with SPP success, the context and environment of private international investment has shifted.

To continue the trend of SPP project development, nations and utilities will have to be even smarter in the future. The playing field will need to be level, the PPA sufficiently neutral and legally functional, and the tariff provide fair incentives for the risk and term undertaken. Haphazardly designed or implemented SPP programs will not succeed in the new environment. Nations and multilateral agencies will need to understand what works, what creates competitive advantages, and what leverages the maximum program resources most efficiently. To succeed in this environment, one will have to have both a desire to make a program work and the resources to be savvier about how to design the program and the PPA. In this sense, this report seeks to embody program SPP program experience to date and provided guidance.

These five Asian nations are pioneers in creating SPP programs to promote new renewable energy development. Each program alone has value in demonstrating and implementing SPP programs embodied in enforceable PPAs. However, cumulatively they provide an energy laboratory during the past decade leaving an inventory of more and less successful program techniques. Comparatively, they illustrate that certain techniques are the tools of choice as these and other nations craft renewable SPP programs as a significant element of their capacity plans.

What does this experience and changing power market trends mean for the future of SPP programs in Asia? Those nations that utilize the lessons of existing SPP programs will best utilize available resources and maximize SPP development. Regardless of one's perspective, in the 21st century, after 20 years of SPP program experience worldwide and 10 years of SPP programs in Asia, an international expectation has evolved for any PPA that is financeable. Certain relationships, provisions, warranties, and sanctions are expected to be incorporated in any PPA if it is to provide the credit support for conventional debt financing and attract equity participation. There is experience in Asia of neutral PPAs that achieve these requirements, as well as unilaterally altered PPAs that became untenable to support an SPP program.

Although many ways exist to operate an SPP program, certain key PPA elements cannot be omitted or significantly changed without compromising the integrity of the program. Those most successful future SPP programs will assimilate international PPA requisites as a base, and layer onto this base innovative country-specific incentives, competitive embellishments, and risk allocation techniques. To strengthen and build transparent and accepted SPP programs in this changing environment the following techniques are relevant:

- **Tuning Up the PPA.** A correctly structured PPA is the legal foundation of the program. Countries should perform a fresh examination of their existing PPAs to harmonize them with the lessons learned to date and the changing investment environment. This is a very quick exercise that can be performed by a legal consultant or a representative working group representing all the various stakeholders. Ultimately, a successful long-term program must operate pursuant to transparent and objectively predictable PPA principles. These must include a PPA that provides a neutral control over obligations and behavior of both parties, and a tariff that reflects avoided cost principles of establishing the value of power. No SPP program can operate at its maximum potential without these elements.
- **Utilizing Competitive Design.** Subsidies of renewable SPPs can be most broadly and cost-effectively implemented with a competitive bid scheme to allocate and determine amounts of subsidies. Competitive bidding can also be used to ration and control the award of SPP entitlements.
- **Perpetuating SPP Program Momentum.** Where certain land resources or land use permits necessary for renewable SPP (for example, hydro or wind) development are under government control, there is an interest in preventing speculative hoarding of both the sites and permits or LoIs to control those sites. A variety of bid security and milestone requirements can minimize such hoarding by extracting an economic rent for holding those entitlements or requiring progress by certain elapsed times.
- **Incentivize the PPA Relationship.** Several fundamental choices are available in designing the PPA to address and regulate the buyer-seller relationship between the SPP and the utility. Embedding financial incentives in the tariff and delivery provisions of the PPA can creatively shift aspects of the legal relationship away from legal sanctions and penalties, and toward internalized self-effectuating market incentives.
- **Update Avoided Cost Principles.** A fundamental issue that must be addressed in every system utilizing long-term contracts is whether and how the SPP will be paid for capacity value of its power. Although some nations have elected to take capacity without paying for it, this diverges from avoided cost principles and creates tension in the long-term utility relationship with SPP developers. Some of these programs have developed creative methods to provide capacity incentives in the PPA tariff structure or to have floating capacity value payments based on peak period delivery performance. PPA tariff structures can be differentiated to provide unique or tiered SPP power sale prices, based on a variety of SPP variables of value to the system, including the baseload nature of the resource, capacity factor, availability, location on the grid, environmental attributes, and other factors.
- **Implement the Proper Solicitation Mechanism.** Programs can alternative between open SPP power solicitations (similar to the traditional PURPA model) or controlled competitive solicitations, as a means to encourage or control SPP proposals. Controlled solicitations for SPP projects can create a hierarchy or “tier” desirability of SPP projects by fuel source, prime mover, environmental attributes, location, system requirements or resource–prime mover diversity, to ensure that full capacity requirements are subscribed in the order of highest value or utility to the national supply plan.

- **Evaluate Innovative Measures.** The future of SPP programs will involve a combination of innovative program design elements to enable private sector credit support for SPP investments: SPP retail sales, retail wheeling, energy banking, and net metering. Experimentation with these elements in Asia has already begun. These creative elements provide sale and “banking” alternatives for what is otherwise a perishable commodity with a single buyer. This allows independent power to move to its most efficient and highest value use. However, these options must be carefully structured, so that the utility receives fair value for transmission and banking services and its power service obligations are not inordinately compromised by these innovative elements. Careful SPP program design and intelligent PPA design is essential to navigating this challenge.

Existing programs and PPAs, in every case, can be improved to better achieve program objectives. A review of existing program at this point in time as the investment environment evolves, as well as careful design of any new programs, will pay significant benefits to the host countries and to multilateral agencies.

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