A Transitional ESI Model for Developing Country

S. Nirukkanaporn and S. Chirarattananon
Energy Field of Study, Asian Institute of Technology
P.O. Box 4, Klong Luang, Pathum Thani 12120
THAILAND

www.serd.ait.ac.th/reric

ABSTRACT

Electric supply industries in developing countries have mostly developed as state-owned monopoly utilities. A typical monopoly utility is responsible for long-term system planning and day-to-day economic operation of the system. Financial resources are provided by or guaranteed by the government. At a certain stage of economic development, the financial requirement for power system expansion becomes an impetus for adoption of the scheme of independent power producer (IPP). The private sector is encouraged to construct, own and generate power for sale to state-owned utility under a long-term purchase agreement. This turns the state utility into the single buyer of electricity. This IPP scheme has worked well and helped alleviate power shortage in many developing countries. But the growth of the IPPs increases the cost of electricity and constrains economic operation of power system. Many developing countries have been encouraged to adopted new competitive ESI structure. This paper illustrates numerically that the IPP scheme in a monopsony ESI structure increases overall costs of power generation and constrains economic operation. It introduces a transitional model that can lead to a new ESI structure that encourages wholesale competition. Development of the model takes into account economic, social, legal and technical constraints existing in a typical developing country.

1. INTRODUCTION

Ever since its discovery, electricity has been used to provide its service to mankind. It provided lighting, other services and amenity, but has also become an essential economic driving force. It drives manufacturing industry, commerce, service industry, agriculture, and enhances development of modern lifestyle. It has been regarded as a welfare goods to be provided by state, [1]. However, this view has now been eroded by the neo-classical economic theory that competitive markets are more efficient than government agencies at delivering basic services. The electric supply industry (ESI) was among the first sector to be privatized in the United Kingdom. Economic theory further teaches that divestiture of state-owned assets would have a flow-on effects of improved resource allocation, innovation and greater employment opportunities, [2] and [3].

The electric supply industry (ESI) in developing countries in Asia are all undergoing, or are under pressure to institute, wide-ranging changes. These come under the pretext of reforms or restructuring. The extent of pressure and speed of reform in different countries may differ, but all involve changing the structure of ESI operating in each country. Another separate but accompanying issue is privatization or change of ownership of the organizations of electric supply and delivery from that of state to private sector. This issue is equally complex. In cases where the electric enterprise has accumulated debts and the state is under pressure to be relieved of financial burden, it is under heavy pressure to sell off the electric enterprise to raise funds or to relief the burden. In case the state enterprise is in sound financial position, management of the enterprise and private sector may be incensed to open up the sector to private participation.

The ESI is complex, its realm of organization includes management of a very complex industry and undertaking of the world's largest engineering structure. However, the complexity is not confined to the physical structure or technological aspect, its management is equally complex.

This paper examines pattern of recent development of the electric supply industry in developing countries in Asia. It reviews the introduction of independent power producers as a means of relieving pressure on investment in power generation capacity. It demonstrates through numerical example how the IPP scheme constrains economic dispatch when the capacity of IPP generators becomes large. It then introduces an ESI model that is conceived as an arrangement alternative to what has been introduced elsewhere. The transitional model appears to be a natural model that is only a short step from the present. However, it could help solve the investment problem. It would enhance private sector participation in the electric sector. It offers a path to smoothly transform ESI from that of state-owned monopoly into a structure that enhances wholesale competition. The paper also presents numerical results of economic dispatch of generations under of various scenarios to demonstrate that the proposed transitional model offers the potential for most economical operation.

2. DEVELOPMENT OF POWER SYSTEM IN A DEVELOPING COUNTRY

Traditionally, the electric power system in a developing country is served by a vertically integrated state-owned utility. At some stage in the past, the monopoly utility was statutorily created by combining small utilities, each might have been operating using different engineering standards. In larger countries, there could be several monopoly utilities, each operating in a franchise area. In smaller countries such as Malaysia and Thailand, the franchise area is the whole of the countries. The World Bank advised the Thai Government to merge existing small utilities to create the Electricity Generating Authority of Thailand as the sole agency for generation and transmission authority in 1968. During this period, private sector was still financially weak and economy of scale requires relatively large investment in large power plants. It was necessary for the government sector to take responsibility to produce electricity for delivery as public goods.

As these traditional monopoly utilities developed, rural electrification and industrialization led to rapid expansion. Least-cost power generation expansion planning has been used as a tool for economic expansion planning. This methodology is well-developed and well-suited to monopoly utilities where transmission expansion planning is also integrated with generation planning to optimize cost of generation and transmission over the planning horizon, while satisfying security and reliability constraints.

These monopoly utilities are also able to plan for economic dispatch of generation to achieve minimum generating cost from utilizing base load, intermediate load, and peak load plants and from plants using different fuels.

2.1 Introduction of IPP

However, as the economy of a developing country expands, electricity demand rises substantially. Expansion of generation and transmission capacity is required to meet increasing demand while attempting to provide equitable access to electricity throughout the whole country. To serve such expansion, government sector of many developing countries are constrained by financial burden from requirements for generation and transmission investment and difficulties in access to financial resources. A scheme independent power producer or IPP is then introduced in order to encourage private investment in electricity generation. The IPPs generate and sell electricity to a state-owned utility under a long-term power purchase agreement (PPA). The scheme helps relieve the state from investment constraint. The government set a ceiling of around $US 2 B per annum for foreign borrowing in Thailand from 1989. The IPP scheme enables generation expansion to continue since the government was not required to be directly or indirectly involved in the investment in the IPP generation. This type of operation has turned the ESI structure from a monopoly to a single-buyer structure. As long as the ESI is regulated, the public policy of cross-subsidization and policy to promote efficient use of energy and renewable energy development can still be met.

Under the single-buyer structure with an IPP scheme, benefits from least-cost planning are retained, while financial obligation of government sector is relieved. In the Philippines, the built-operate-transfer (BOT) IPP scheme successfully solved the power crisis in 1990s when the country experienced rotating brownouts [4]. In China, the IPP scheme helped solve serious shortage of generation capacity existing during 1985 [5]. By early 1990s, capacity of IPP generation reached 50% of total. The power system operation is centrally managed but the conditions of power trade under PPA need to be incorporated. The PPAs are negotiated contracts between generators and single-buyer. Each PPA has its own specific clauses. However, most PPAs contain conditions that attract private investment and guarantee that investors are protected form market risks under the single-buyer structure. As a result, traditional PPAs in many developing countries are long-term, virtual must-run contracts [6], which extends through the plant's life. Moreover, the terms in the PPAs were designed to attract foreign investment in countries perceived to offer high risk. The resulting electricity prices are often said to be expensive later.

The terms of payment in a PPA comprises energy payment (EP) and capacity payment or availability payment (AP). Energy payment represents payment for kWh of electrical energy that is actually generated and is paid based on a generator's heat rate and fuel cost. Availability payment (AP) is related to the plant's availability and is designed to cover the capital cost and fixed operating and maintenance cost over the life time of the IPP.

The terms of obligation of these PPAs render them virtually must-run or take-or-pay contracts. This means that the IPPs practically must be selected to operate although there might be other generators that can provide output at lower costs. Most IPPs aim to serve demand as baseload plants. A baseload plant prefers to operate at their most economic generating level with small fluctuation in their output. Some contract specifies certain limits for the variation of the IPP plant's output within a day. With increasing capacity of IPPs in the system, the virtual must-run contracts have started to constrain the economic dispatch of generation and have resulted in increasing cost of power generation. The scheme of IPP that has been introduced successfully for a decade in China, the Philippines, Thailand, and other Asian countries has added substantial generation capacity into the respective countries. However, the terms of the PPAs used have eventually manifested to create constraint in economic generation dispatch. The terms of PPAs are also generally protective of IPPs during financial turbulence. During the recent financial crisis in Thailand, the IPPs were able to negotiate to adjust the terms of payment to relate to $US amidst the falling value of Thai Baht. On the one hand, this flexibility would add to the reputation of the government and of the country of its responsibility and willingness to share risks with foreign investors. On the other hand, it also adversely raises the issue of risk allocation. Some strong criticisms emerge that this system passes all the risks to consumers.

2.2 Competitive ESI

In Korea, Malaysia, Philippines, Taiwan, Thailand and even in China, experiences gained from implementation of IPP scheme have led to a search for new ESI structure that can still offer opportunity for private sector participation in the industry but that can also avoid or eliminate the constraints that have emerged. It has been perceived that competitive ESI structure should be introduced. In Thailand, international consultants were invited to advice on a suitable structure for Thailand. The consultants engaged by an energy planning office recommended a structure based on the system used in the United Kingdom (UK) prior to 2001. This structure mandates competition in generation and retailing and is proposed to operate an office for competitive bidding of sales and purchases of power generation called a Power Pool. There were strong objections and criticisms of the proposed structure by industry participants. Issues raised included uncertainty over new capacity addition under this system to meet growing demand (There has been continuous growth in power demand of close to 10% annually, except for 1998 and 1999, the years immediately after the advent of the financial crisis). When the California power crisis broke out, objection to the Power Pool became stronger. Immediately after the California crisis, the Malaysian government froze the on-going process of adopting a complete competitive structure. The National Energy Policy Office (NEPO) in Thailand then proposed a scheme called National Electricity Supply Arrangement, modeled after the National Electricity Trading arrangement (NETA) introduced into UK during 2001. Another consultant engaged by the Electricity Generating Authority of Thailand proposed a competitive wholesale trading system called cost-based power pool modeled after the system used in Argentina.

As a result of the power crisis event in California, the World Bank and World Energy Council publishes documents to caution governments of developing countries against rushing to adopt completely competitive structure. The World Bank document suggests examining a multiple-buyers multiple-sellers model and the cost-based pool model used in Latin America [7]. The multiple-buyers multiple-sellers model would not function if the system in a country is too large, and the existing systems in medium-sized developing countries such as Malaysia, the Philippines and Thailand are already too large to implement such system. The cost-based power pool system requires a complete change from the existing structure. It is uncertain how the power pool could function with all new rules and new roles for industry participants.

The Asian Institute of Technology (AIT) was invited by EGAT to undertake a study to propose a suitable ESI Structure for Thailand. The study team of AIT eventually proposed a transitional model based on the use of a system(s) agent (AGE) or SAGE [8].

The model is conceived out from a backdrop of a successful single buyer utility progressively constrained by a high percentage of IPP capacity with long-term PPAs. The system load growth is high. The country is developing with a positive financial outlook. The financial position of the government is positive, but is still strained by obligation to provide social services such as free education (up to pre-university level) and universal health care. The government is also strained by the financial obligation for the development of public infrastructures. Such description is in consonant with many developing countries in Asia for which the model to be described is expected to be applicable.

3. A TRANSITIONAL MODEL

The proposed model is deemed a transitional model for the reason that partial competition is introduced. To an extent, an agent of state in this model would still perform as a single buyer, but this role would be gradually reduced as the size of customers the state is obligated to serve reduces. The rationale behind the conceptual development of this model is outlined in the followings.

3.1 Rationale

- Our model developing countries possess growing economies with increasing consumption of electricity. Per capita consumption of electricity is still low by international standard. Foreign investment is still required in ESI. The authors believe that some mechanism to ensure timely investment by private sector in power generation is still required and should form a part of the proposed ESI structure.
- Our model developing countries have gross income disparity among their population, social equity policy should be pursued by governments. In this respect equitable access to electricity

irrespective of geographical location is desirable and some form of subsidy for the lower income groups should still be implemented. Taken an example of Thailand, the policy of maintaining uniform tariff throughout the country has worked well. Progressive tariff that charges a low rate for smaller consumption and higher rate for higher consumption by residential customers should be maintained. Cross subsidy among customers in the residential category has functioned well. A competitive retail ESI structure would not be amenable to such policy, at lest for the transitional period.

- For developing countries with limited resources, energy conservation should still be rigorously pursued. The rationale for this is consistent with a vertically-integrated industry or other industry structure that accounts for the cost of electricity generation and capacity investment on behalf of the public. The vision here is that mass sell off of present generation assets or investment of merchant plant under speculative purpose would not and should not occur. The proposed ESI structure must still be amenable to implementation of demand-side-management program. Savings from DSM program would accrue benefits to customers as well as to the society.
- The proposed structure should enhance regional cooperation in electricity generation and trade. The countries in our model are still developing. A country possessing resources for power generation is unable to unilaterally develop the resources and build the required power plants. Long-term commitment in the form of PPA is required to attract foreign investment for construction of power plants. The proposed ESI structure must be flexible to accommodate such mechanism for long-term commitment.
- Traditional monopoly utilities and single buyer utilities are not able or not willing to unbundle the costs of electricity delivered to customers. The cost of generation, transmission, distribution and retailing are bundled. Conceptually, these can be unbundled, but in an integrated utility these costs are internalized. The proposed structure should possess inherent ability or mechanism to unbundle these costs. The costs would become more transparent and cost setting mechanism or action challengeable.

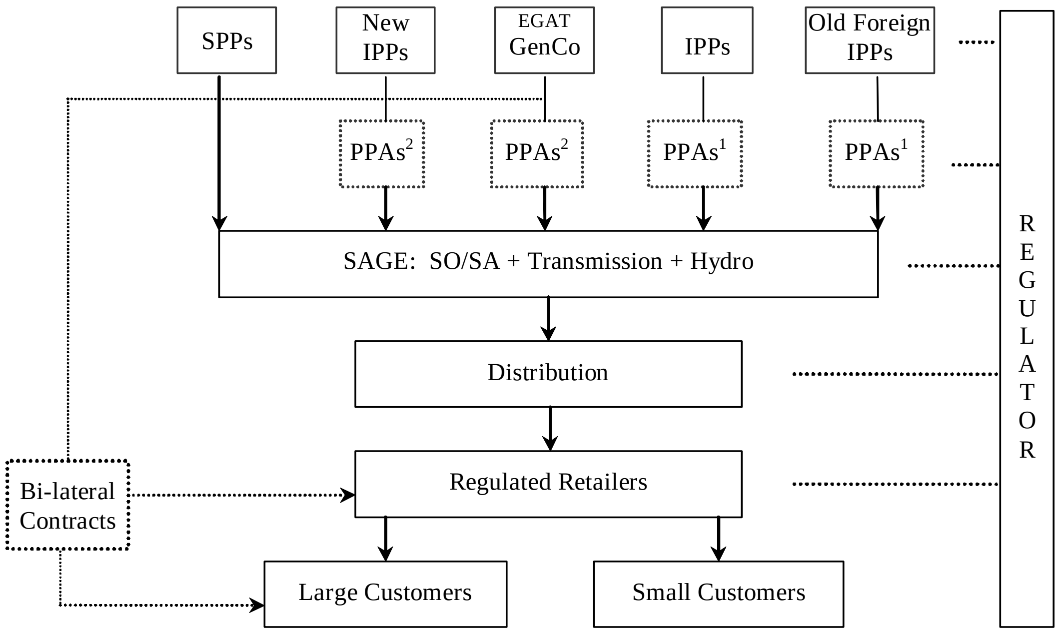
3.2 Structure of the Transitional Model

The authors assumed that the present ESI is operating under a single-buyer model with the IPP scheme, operated by a vertically-integrated state-owned utility. Under the transitional ESI model, competition is firstly introduced in generation.

Unbundling of generation from transmission is recommended in the early phase of the reform so that all generators will face a fair competition. Transmission and system operation should operate as one entity set independently of other players in the industry.

A modified form of IPP arrangement with more competitive PPA is created in order to enhance private investment in power generation. Existing PPAs are still honored while new PPAs require terms and clauses designed to be more competitive. Risks should be shared between all players in the industry and generators should not be completely protected by the PPA. Bilateral contract is allowed for electricity trading between generators and large customers to create competitive situation of multiple-buyers and multiple-sellers. Fig. 1 illustrates the transitional model.

Existing IPPs, both foreign and domestic, opting to retain the original PPAs connect and sell power to the System AGEnt (or SAGE). Those opting to change to new PPAs are classified together with new generations as new IPPs. The System Agent (SAGE) is established from the remaining units of EGAT after all generating facilities have been unbundled. These comprise transmission, system operator, and an office to settle transactions. The main functions of SAGE are system operation, settlement operation, domestic hydropower generation and transmission. Unbundled generation units and new IPPs enter into new competitive PPA arrangement with SAGE.



Note: 1 Represents the existing PPAs
2 Represents the competitive PPAs

Fig. 1 Recommended transitional ESI structure [8]

The competitive PPA arrangement resembles bilateral contract. The contracted capacity and energy is less than the full capacity of each generator and the duration of each contract is shorter. Under new PPAs, competitive generators, which include EGAT GenCo and new IPPs, can utilize a part of their respective capacities by selling generation in excess of contract with SAGE to large customers directly or to SAGE in competitive offers. Large customers may source electricity directly from competitive generators or from regulated retailer, which is formed from the existing retailing units of MEA and PEA. The regulated retailers source their power from SAGE, and are not expected to source directly from the generators. Competitive retailing is not introduced in this phase. With this arrangement, social policy can be implemented for regulated customers.

Most hydro power sources in Asia can be scheduled to run only during certain period of a day. The reservoirs are rain-fed and the water is used for irrigation. Hydro generation is scheduled to serve peak load. In such a case, hydro-power resource is transferred to SAGE to form part of the tools SAGE could use for energy balancing.

Spinning reserve and black start obligation are required on all IPPs. Reactive power purchase can be offered by IPPs to SAGE.

3.3 Structure of a Competitive PPA

The general structure of a new competitive PPA for new IPPs and EGAT's Gencos is recommended as follows:

- The payment in each PPA comprises of two parts – energy payment (*EP*) and availability payment (*AP*), which are also present in the existing PPAs. Availability payment (*AP)* represents payment to contracted capacity and other fixed cost. Energy payment (*EP)* is given to offset variable operation and maintenance cost (to be adjusted by actual fuel cost).

- Although each IPP is contracted by SAGE through competitive bidding, it is required that the capacity of each new IPP exceeds the contracted capacity. The capacity of each new IPP is determined by the total system demand plus required system reserve at the time the new IPP plant comes into operation. The capacity that SAGE would be obligated to use and is contracted is determined by the obligation of SAGE to its regulated customers. This could mean that when bidding for new IPP is made, the capacity to be contracted by SAGE could be 600 MW, but it is required that the IPP must construct another generator at 300 MW or use other means that will render the combined capacity to reach 900 MW. The 300 MW capacity is calculated to be required partly by unregulated customers and partly as reserve for system reliability. In principle, the cost of reserve capacity must be shared by all customers. Capacity contracted by SAGE includes spinning reserve and scheduled reserve required for system security and reliability.
- The type, size, and fuel to be used by each new IPP plant in each call for bidding are determined by the regulator to fulfill the requirements of the whole system and the country. Specification of fuel to be used would be made on the basis of fuel security, environmental constraint, and other requirements.
- The capacity payment would be related to the estimated cost per unit size of the given type of power plant.
- Each PPA would contain clauses on contingency requirements such as black start obligation.
- Each new IPP can sell its uncontracted power to large customers, but its contracted power with SAGE must be available at all times.
- Each IPP may offer reactive power support to SAGE on a regular basis.

4. ECONOMIC OPERATION OF THE TRANSITIONAL MODEL

In this section we will illustrate how the terms of present PPAs constrain system operation and how this affect economic dispatch and generation cost. Four scenarios are examined as will be described.

Let us examine the situation of power generation in Thailand, which is one of our model countries. We intend to create a reference ESI model for use in the illustration scenarios from the Thai ESI [9].

In Thailand, natural gas, fuel oil, coal (domestic and imported) and hydro resources are available for power generation. Natural gas is used both for thermal (steam turbine) and combined cycle generation. Fuel oil and coal are used in thermal generation. Combined cycle generation would not respond to load change well and is used mainly to meet base load. Thermal generation is more flexible and is used to meet base and partial peak loads. For peak load, gas turbines using natural gas and diesel oil, and hydro are available. In the particular year that we examine, hydro and gas turbine are used to meet peak load. Fig. 2 shows the load in a peak day.

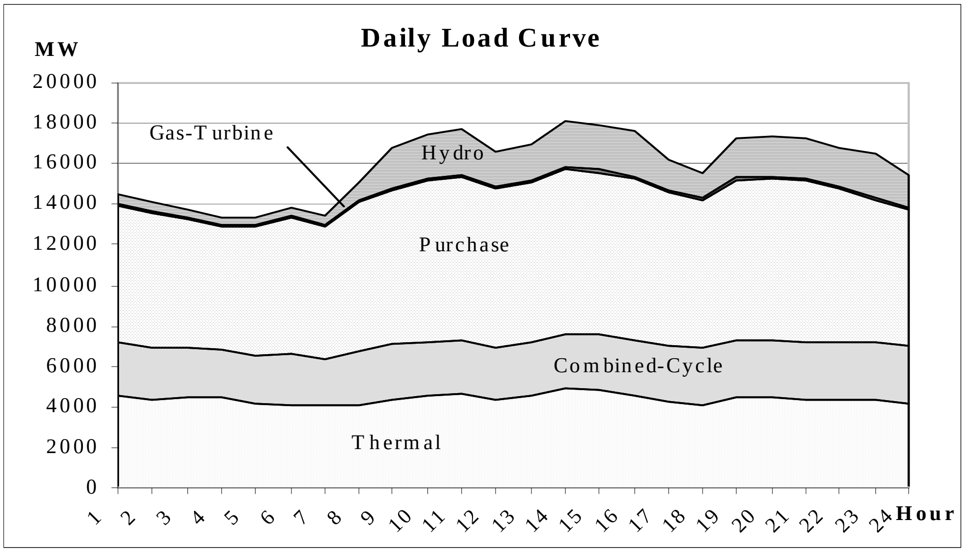


Fig. 2 Load shape of Thai system in a peak day

4.1 Description of the Reference ESI Model

Fig. 3 illustrates the industry structure of our reference ESI model. It is a single buyer model where the utility is vertically integrated. The utility possesses and operates transmission, distribution and some generation plants. All IPPs, domestic or foreign, sell all power generated to the single buyer using agreed PPAs. The system operator dispatches generation in accordance with the terms of PPAs and whenever possible, economic criterion.

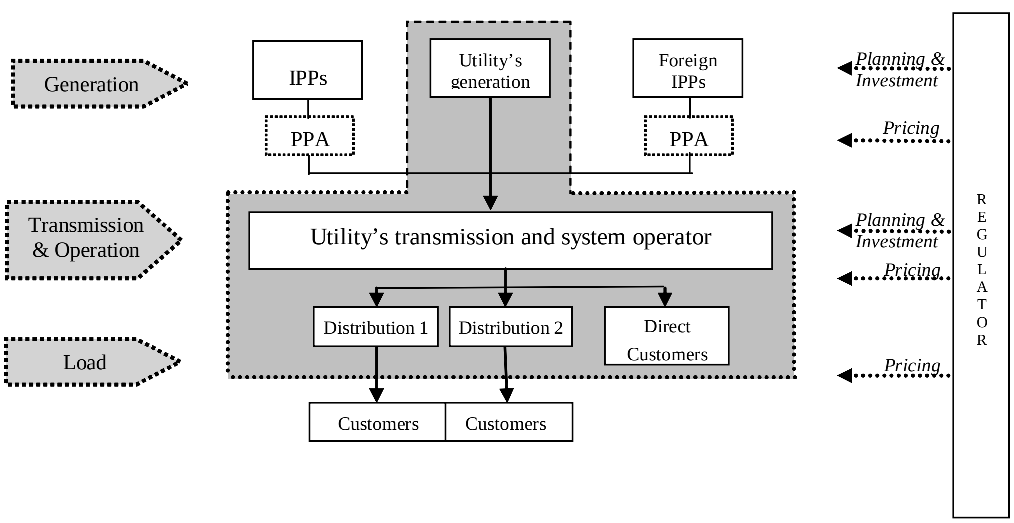


Fig. 3 Structure of the Reference ESI Model

In the case of Thailand, hydro and gas turbine generations are used to meet peak load as is seen from Fig. 2. Also, IPPs operate only thermal and combined cycle generations. In order to simulate this situation, we therefore remove the peak load met by hydro generation from the Thai load shape of Fig. 2 to form the load shape of our reference system. This reference 24-hour load shape is shown in Fig. 4. This will be used with unit commitment exercise to calculate cost of generation under each scenario.

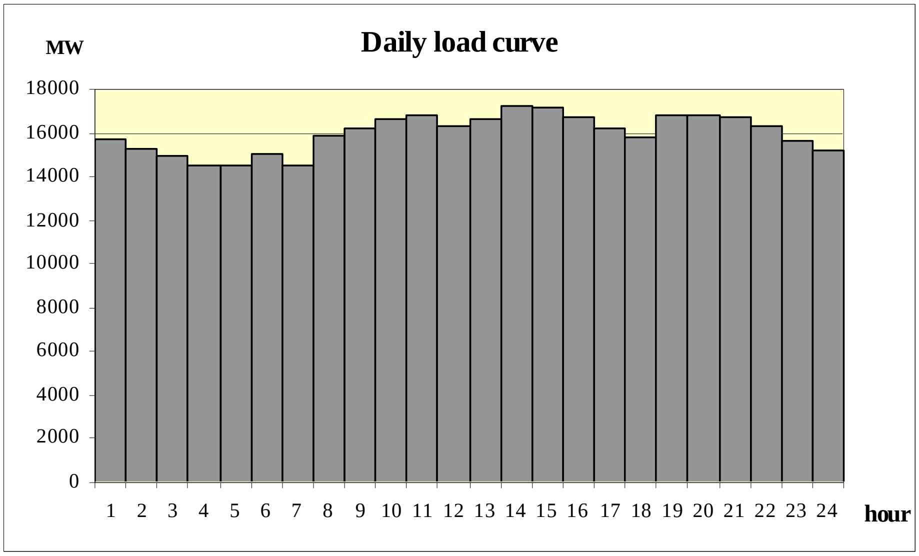


Fig. 4 Reference system load shape

The generating capacities of the utility and of the IPPs of the reference ESI model are summarized in Table 1. These capacities exclude hydro and fuel oil generation. Under the situation of high projected growth in demand and financial constraint in the government sector, substantial capacity from private investors has been added. The capacity of IPP in the reference system accounts for approximately 50% of the total installed generating capacity. Most of the IPP capacity in the reference system is combined-cycle generation using natural gas.

Table 1 Generating capacity in the reference system

Types of power plant	Total generating capacity (MW)
Utility	10,046
Gas-fired thermal	3,134
Coal-fired thermal (lignite)	2,216
Gas and steam turbine combined-cycle	4,520
Gas Turbine	176
IPPs	11,497
Gas-fired thermal	1,610
Coal-fired thermal	1,346
Gas and steam turbine combined-cycle	8,541
Grand total	*21,543*

The IPPs sell power to a single-buyer utility under long-term PPAs and additionally receiving capacity payment to allow for their capital cost recovery. Both of the operating condition and payments are set to attract private investors. In the following 4 scenarios, only generation costs are used for comparison. Capacity costs are not used.

The heat rate, minimum and maximum operable power outputs of each generator forming power plants of the utility and of the IPPs in Table 1, and costs of fuels are given in the Appendix.

The authors will use per unit energy cost as a parameter to compare results of economic dispatch under various scenarios of power system operation. Unit commitment or economic generation scheduling based on a 24-hour period is applied to find such cost. The total energy cost of the duration is averaged to find per unit energy cost ($US/kWh).

Unit Commitment

In unit commitment, generators are selected each to generate at a level that the combined output matches the load hourly and at lowest cost for the entire period subject to constraints [10].

The constraints in our case include required system reserve, spinning reserve, generator operating characteristics and limits.

If the total maximum operating capacity of each generator in the Appendix are added, this total capacity equals to the total capacity in Table 1 and exceeds the peak hourly load in Fig. 4 by 23%. The reference system has a reserve capacity of 23%.

In our case we assume that 7% fast spinning reserve (10-minute reserve) is required for the system. Coal-fired power plants will not be able to contribute to this reserve. As a result, the spinning reserve from each thermal and combined cycle generator in all scenarios is found to be about 10% of the capacity of each generator.

The characteristics of a generator in our case comprise its heat rate, operating limits, allowable start-up duration and allowable shut-down duration. The normal operating limits P_{min} and P_{max} of each generator are the minimum and maximum power limits respectively a generator is allowed to operate. But as is seen in the description of Scenario 3, additional limits of operation may be imposed in the PPAs. A thermal generator requires a long start up time, so when it is started up, it is normally not shut down in the normal operation. The results from all scenarios show that either a thermal plant is selected to run the entire 24-hour period or not chosen at all. The gas turbine part of most combined cycle generators require approximately one hour for starting up and synchronizing onto the system. Most also require that once a shutdown is executed, at least 3 hours are required before a startup can be executed.

4.2 Description of the Scenarios

Four scenarios are set to illustrate different operations of the reference ESI model under monopoly structure, under single buyer models with different PPA arrangements and under the transitional structure.

4.2.1 Scenario 1: base case

In this case all generators, both of the utility and of IPPs, are selected to operate in the most economical way, subject only to its characteristics and operating limits. The resulting figure of average energy generation cost is used as a reference for comparison with results from other scenarios.

4.2.2 Scenario 2: must-run PPA

The negotiated contract between an IPPs and a single-buyer normally contain virtual must-run conditions. Some are specified in terms of allowable (limited) numbers of startups and shutdowns per annum. These conditions guarantee that the IPP will consistently generate revenue throughout their contract life. This scenario is formed in order to illustrate that the virtual must-run clause of IPP scheme constrains economic operation. Under this scenario, generators in the system are divided into two groups, utility's generating units and IPPs. Utility's generators are selected to operate on economic ground, while generators of all IPPs are brought online for all hour of the 24-hour interval, assuming no planned and unplanned outage. The technical operating limitation, P_{min} and P_{max} of all generators are observed.

4.2.3 Scenario 3: must-run PPA with limited range.

The negotiated PPA often comprises some clauses to assure that the IPPs will be running their generators to serve baseload with small fluctuations of their output power. For example, the range that an IPP combined-cycle generator output can be varied is within 20 percent of the nominal maximum output, as in Eq. (1).

$$\textit{Load range (\%)} = \frac{(D_{\max} - D_{\min})}{D_{\max}} \times 100 \qquad (1)$$

where, D_{max} = Maximum output of generator exclusive of spinning reserve, and
D_{min} = Minimum output of generator.

This scenario is set to test if the load-variation limit increases constraint on economic generation. Normally a generator is operated within its technical generating limits, P_{min} and P_{max}, but the load range here imposes further restriction.

4.2.4 Scenario 4: competitive PPA under the transitional ESI model.

This scenario is used to illustrate operating conditions of the "transitional model" in section 3. Generators under this scenario are divided into 2 groups - existing IPPs and new IPPs. The first category includes all IPPs that operate using existing PPAs. The latter consists of new IPPs and unbundled utility's generators. It is assumed that existing IPPs would opt to retain their PPAs with SAGE. New IPPs and unbundled utility's generating companies sell generated power to SAGE under competitive PPAs described in Section 3. Competitive PPAs do not contain 'must-run' condition.

Under competitive PPA, the non-contracted capacity of an IPP generator can either be traded in free market, or bid to sell to SAGE to supply to captive market or to serve system balance. More importantly, the contract with no 'must-run' constraint allows economic dispatch of generators.

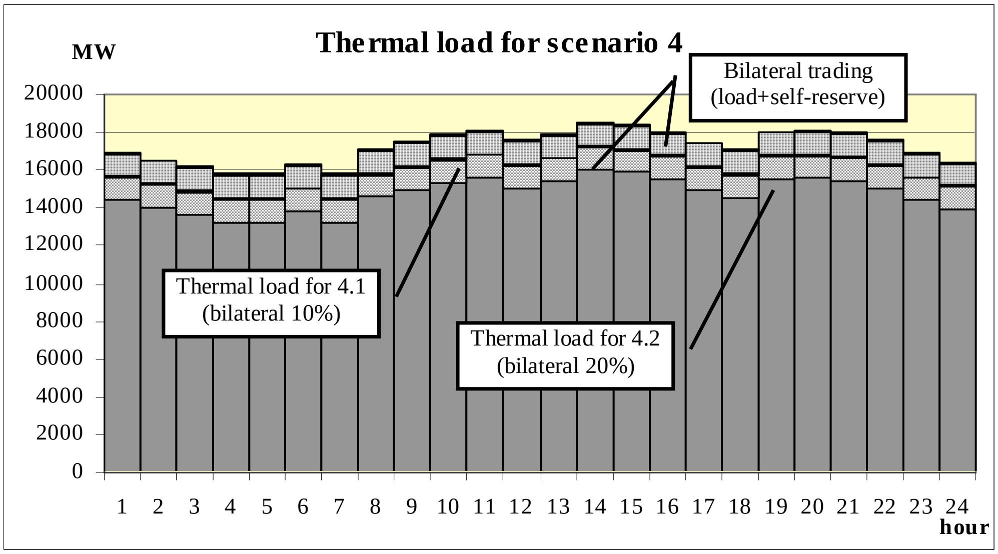


Fig. 5 Loads to system operator in Transitional Model

In this competitive situation, it is assumed that the new IPPs are able to sell to large customers through bilateral trading. The remaining load SAGE must supply is reduced as shown in Fig. 5. Here, it is assumed that the capacity of each generator of competitive IPPs is reduced corresponding to 10% and 20% respectively of system loads that these generators supply to large customers through bilateral trading.

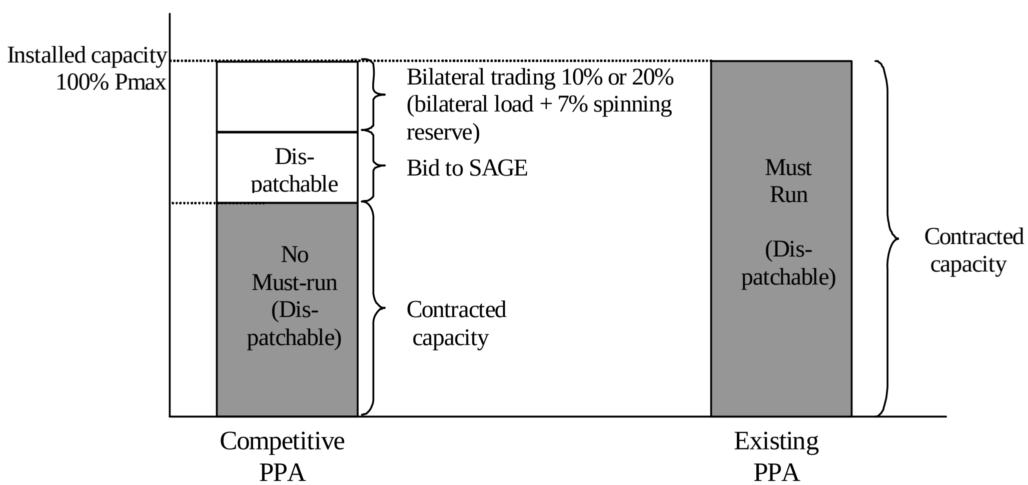


Fig. 6 Capacity usage comparisons between existing and competitive PPA

A competitive PPA requires that contracted capacity of competitive IPP generation be available to SAGE. Therefore, these generators can utilize their remaining capacity in manners illustrated in Fig. 6. It is assumed that each generator uses 10% of the installed capacity in one case and 20% in another case for bilateral trading. The remaining uncontracted capacity could be purchased by SAGE through competitive offer.

All scenarios included in the analysis are summarized in Table 2.

Table 2 Scenario descriptions

Scenario 1: base case	All generators are economically dispatched
Scenario 2: must-run PPA	IPPs are operated under the must-run PPA constraint only. Contracted capacity is set at 100% installed capacity
Scenario 3: must-run PPA with limited load range	IPPs are operated under PPA constraints: 1. virtual must-run 2. limited load range Guaranteed capacity payment is set at 100% installed capacity
Scenario 4: competitive PPA	Guaranteed capacity payment is set at a fraction of installed capacity, with no must-run condition. 4.1 bilateral trade 10% of capacity 4.2 bilateral trade 20% of capacity

4.3 Results and Discussions

The average per unit energy costs resulting from unit commitment of generation over the 24-hour period of all scenarios are shown in Table 3. With respect to the result of the base case, scenario 1, the implementation of IPP schemes (scenario 2 and 3) increase the per unit energy costs as a result of the virtual must-run constraint in the PPAs. Generators of IPPs have priority in operation and some generators of the utility may not be dispatched even though these may offer lower costs. The resulting system operating cost in Scenario 2 and 3 are higher that that of Scenario 1.

Table 3 Unit energy costs of different scenarios

Scenario		Average per unit energy cost ($US/kWh)
1	Base case	0.02895
2	Must-run PPA	0.02915
3	Must-run PPA with daily load range	0.02915
4.1	Transitional model – competitive PPA with 10% bilateral trade	0.02875
4.2	Transitional model – competitive PPA with 20% bilateral trade	0.0249

Scenario 2 and 3 do not indicate any difference in the per unit energy, which illustrates that the limiting load range of IPPs does not affect operation of the generators significantly. This implies that most generators are operated at load levels close to P_{max}.

The authors applied lighter load of 10,000 MW to scenario 2 and 3 to test this hypothesis. The results show small increase in energy costs. The latter results imply that the limiting load range still constrains the power system operation. The effect seen is small.

Scenario 4 shows decrease in per unit energy cost. The resulting per unit costs are lower than that of Scenario 1. The reduction is due to several reasons. In this Scenario the 'must-run' constraint for IPPs is not present in the transitional structure. Therefore, the generators are freely selected based on the economic criteria. The transitional model allows new IPPs holding competitive PPAs to utilize uncontracted capacity through bilateral trading or to sell this capacity to SAGE. Generation to fulfill bilateral contract reduces the load the system operator must run to balance the system, but all the generators are still available (although each at reduced capacity) to dispatch. In each case in this

Scenario, the load to the system operator becomes smaller but the number of generators available to the operator remains the same. Therefore, the resulting operations produce lower per unit energy costs.

In summary, it is clearly illustrated that the clauses in the purchase contract that have originally been designed to attract private investment add constraints to power system operation. The effects from these constraints could be large in case the total capacity of the traditional IPPs become large and the generators of the utility are used virtually to serve balancing and ancillary functions.

5. CONCLUSIONS

The IPP scheme has proved its success in reducing financial burden in generation expansion development from governments of developing countries. However, further expansion of the scheme has been demonstrated to constrain economic operation of a power system. Many countries in Asia have reached a common critical juncture. The power demand in each country increases between 5 to 10% annually. Competitive ESI structures have been introduced in developed countries, especially those possessing robust economies and advanced technology for management of its ESI. Similar structures have been proposed to developing Asian countries. The events in California during 2001 and other similar events have demonstrated that the risks involved in changing the existing ESI structure in a country to a completely new and competitive structure could very large. The transitional structure proposed in this paper may be a viable alternative. The structure offers a gradual transition from the existing structure. The model can continue to be used to relieve the state of the problem of financial burden for investment in power generation to meet rising demand. It is shown in this paper that the model can be used to achieve economic generation. The model also has the potential to achieve economic investment in power system expansion, as will be demonstrated in a future paper.

6. REFERENCES

[1] Cope, D. 2000. Electricity Sector Deregulation in the APEC Region. Asia-Pacific Energy Research Center, Institute of Energy Economics, Japan.

[2] Becker and Becker. 1997. *The Economics of Life*: Mc Graw-Hill.

[3] Kahn, E. 1998. *The Economics of Regulation*: The MIT Press.

[4] Roxas, F.Y. 1999. Chapter 18 of Second Workshop on Economic Cooperation in Central Asia: Challenges and Opportunities in Energy. In *Conference Papers and Proceedings, Asian Development Ban.* BOT in the Philippines, http://www.adb.org.

[5] World Energy Council. 2001. Electricity Market Design and Creation in Asia Pacific. London, UK.

[6] Bacon, R. 1995. Competitive Contracting for Privately Generated Power - What to Do in the Absence of Competition in the Market. Public Policy for the Private Sector. The World Bank, May, http://www.worldbank.org.

[7] World Bank. 2001. The California Power Crisis: Lessons for Developing Countries. http://www.worldbank.org.

[8] AIT. 2002. Electricity Supply Industry Reform in Thailand - Final Report. Submitted to the Electricity Generating Authority of Thailand. September.

[9] Electricity Generating Authority of Thailand (EGAT). 2003. Power Development Plan (PDP 2003).

[10] Wood, A.J. and Wollenberg, B.F. 1995. *Power Generation, Operation, and Control*. Canada: John Willey and Sons.

7. APPENDIX

Table 4 listed the characteristics of generator. Under unit commitment of generation, generators are operated within their operating limit, ranging from their P_{min} to P_{max}. The total operating cost of generation is minimized in the unit commitment algorithm by using the cost function of each generator. This cost function can be derived from multiplying generator's heat-rate with fuel cost.

Generator's heat rate is represented by the following Eq. (2).

$$Heat\ Rate\ (MMBTU/hr) = a + bP + cP^2 \tag{2}$$

Generator's cost function can be found from Eq. (3),

$$Cost\ function\ (\$US/hr) = Heat\ Rate\ x\ \ Fuel\ Cost \tag{3}$$

where, fuel costs are listed in Table 5.

Table 4 Generator's characteristics

Gen ID[(1)]	Plant Type[(2)]	Fuel Type[(3)]	Pmin (MW)	Pmax (MW)	Heat Rate (MMBTU/hr)		
					a	b	c
1	CC	G	256	358	-2839.60	7.200	0.0030
2	CC	G	187	307	1.00	7.300	0.0020
3	CC	G	187	307	4.60	7.550	0.0015
4	T	G	240	525.5	354.03	8.800	0.0004
5	T	G	240	526.5	421.20	8.340	0.0008
6	T	G	268	576	531.90	8.500	0.0017
7	T	G	268	576	320.12	9.200	0.0004
8	GT	G	14	176	1.00	12.000	0.0022
9	T	L	150	276	357.23	10.625	0.0043
10	T	L	150	276	1061.23	6.030	0.0105
11	T	L	150	276	571.96	4.410	0.0063
12	T	L	150	276	571.96	4.410	0.0063
13	T	L	90	140	63.23	9.603	0.0011
14	T	L	90	140	63.23	9.603	0.0011
15	T	L	90	140	63.23	9.603	0.0011
16	T	L	90	140	63.23	9.603	0.0011
17	T	L	150	276	1442.04	6.300	0.0066
18	T	L	150	276	618.07	6.300	0.0066
19	CC	G	180	355	864.13	6.000	0.0043
20	CC	G	180	355	449.21	7.970	0.0001
21	CC	G	250	316	122.80	6.800	0.0025
22	CC	G	426	562	-1.60	5.700	0.0025
23	T	G	180	310	213.80	8.980	0.0001
24	T	G	180	310	213.53	8.900	0.0015
25	T	G	180	310	213.70	8.960	0.0001
26	CC	G	236	630	636.00	5.700	0.0017

Gen ID(1)	Plant Type(2)	Fuel Type(3)	Pmin (MW)	Pmax (MW)	Heat Rate (MMBTU/hr)	Gen ID(1)	Plant Type(2)
27	CC	G	236	630	598.10	5.700	0.0017
28	CC	G	236	700	1414.19	5.700	0.0011
29	CC	G	376	678	820.30	8.130	0.0000
30	T	G	50	70	8.88	11.227	0.0000
31	T	G	50	70	30.12	12.590	0.0000
32	CC	G	250	700	532.00	6.500	0.0015
33	CC	G	250	700	540.00	6.500	0.0015
34	CC	G	250	700	532.00	6.500	0.0015
35	T	G	140	735	-489.36	6.959	0.0030
36	T	G	140	735	-489.40	6.959	0.0030
37	CC	G	230	300	-0.01	7.300	0.0035
38	CC	G	230	300	-0.01	7.300	0.0035
39	CC	G	230	300	0.00	7.300	0.0035
40	CC	G	230	300	0.00	7.300	0.0035
41	CC	G	350	713	657.37	7.491	0.0000
42	CC	G	160	350	922.00	7.094	0.0000
43	CC	G	350	700	-562.70	7.930	0.0000
44	CC	G	343	700	922.00	7.094	0.000
45	T	C	200	673	1083.40	9.324	0.0000
46	T	C	200	673	1075.40	9.324	0.0000
47	CC	G	100	350	922.00	7.094	0.0000
48	CC	G	100	350	922.00	7.094	0.0000
49	CC	G	200	700	532.00	6.500	0.0015
50	CC	G	200	700	532.00	6.500	0.0015

Note: (1) Gen 1-28 are utility's generators,
Gen 29-40 are IPPs from divestiture of utility's assets,
Gen 41-44 are existing BOO IPPs,
Gen 45-50 are new BOO IPPs,
(2) CC, T and GT refers to combined-cycle, thermal and gas-turbine plant, respectively, and
(3) G, L and C refers to natural gas, lignite and imported coal, respectively.

Table 5 Fuel costs

Fuel type	Fuel cost ($US/MMBTU)
Natural Gas	3.9
Lignite	1.8
Coal Import	2.1