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# Generator Revenue Adequacy in the Competitive Electricity Markets: The case of Malaysia

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**Abstract:** Malaysia, like many other developing countries, is reforming its electric supply industry into a more transparent, efficient and competitive environment. The introduction of Independent Power Producers (IPPs) in 1992 was the first step taken to encourage the private investors to participate in the generation sector. The adoption of the single buyer market model in 2001 was a step further to create competition in generation. However, these efforts invite the financial crisis due to IPP generation capacity price obligation and generation surplus as stated in the Power Purchase Agreement (PPA). As the PPA is coming towards the end, the pool market model was initially identified as a possible model to overcome the weaknesses of the single buyer market. However, this model could invite a lot of denials from the power producers if it is not implemented properly. This paper proposes a hybrid market model to satisfy the generator revenue adequacy in Malaysian electricity markets under a competitive environment. A case study of Malaysia's electricity market system is used to illustrate the proposed market. The result shows that the proposed market model has merit over a pool market model in the context of guaranteed revenue remuneration for each generator. The hybrid model proposed in this paper could effectively be used by ESI in developing countries as a first step of introducing a competition in their electricity market.

**Keywords:** Supply Industry (ESI), single buyer market, pool market, load sharing

## 1. Introduction

Historically, a privately owned vertically integrated utility (VIU) carried out the supply of electricity. Generation, transmission and distribution were owned and managed by the same utility over a certain area. In some countries (e.g. Malaysia), the VIU was previously owned by the government. Later, the electricity supply industry (ESI) underwent a major transition worldwide, as new technology and attitudes towards utilities are being developed and changed. Basically, the objectives of these transitions are to enhance efficiency, to promote competition in order to lower costs, to increase customer choice, to assemble private investment, and to merge public finances. The tools of achieving these objectives are the introduction of competition, which is supported by regulation and the encouragement of private participation. These changes helped introduced a number of electricity market models, which include not only the structure models of ESI but also the electricity trading arrangements.

Usually these models are designed appropriately with their local conditions and are being upgraded from time to time based on current issues that arise. There are four basic market model structures of the electricity supply industry that have been widely adopted such as: the vertically integrated utility or also known as a monopoly model, the purchasing agency model, the wholesale competition model and the retail competition model [1]. These models seem to be the steps or processes in order to achieve the ESI objectives and build a better structure.

There are also several countries that have tried to change the structure instantaneously, but it requires a detailed design as the complexity of the market model is proportional to the types of competition that are being held. The trading arrangement, on the other hand, is used as a method of measuring and accounting for flows into and out of the network, or over interconnectors, for transactions to be invoiced and paid [2].

For developing countries with small systems, the simpler and more modest market based on competition for the market or contracts are recommended [3]. There are several types of electricity trading arrangements applied in deregulated structures such as: single buyer market, pool market, bilateral contract and multilateral market.

## 2. Electricity industry in Malaysia

As a developing country, Malaysia is also following the worldwide trend to reform its electricity supply industry. Malaysia Electricity Supply Industry (MESI) started in 1894 when a private entity had generated electricity for its own consumption. In 1949, a national company named Central Electricity Board (CEB) was established, which later changed its name to National

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Electricity Board (NEB) in 1965. The government of Malaysia has corporatized in 1990 and later privatized the NEB in 1992 under the name of Tenaga Nasional Berhad (TNB). The structure of TNB was unbundled to three private companies, namely TNB Generation Sdn. Bhd, TNB Transmission Sdn. Bhd and TNB Distribution Sdn. Bhd. However, the company structure remained vertically integrated and under regulated monopoly. The monopoly status of TNB on generation sector ceased when the Malaysian government decided to introduce the private investors - the Independent Power Producers (IPPs) in 1994.The decision made is believed due to the massive blackout that occurred in September 1992, which affected nearly 18 million people for 48 hours. After an investigation on the nation's power generation industry, the result verified that the nation's Power Company was unable to cater the growth in power demand due to the rapid development in several sectors such as residential, commercial, industrial and transport [4]. This incident is reported as the third in world's worst power outages. It was also reported that the business loss for this outage was 220 million Malaysian ringgit which affects manufacturers in Malaysia's Silicon Valley and briefly halted trading on the national stock exchange.

The introduction of IPPs in the generation sector is aimed not only to aid TNB to overcome the electricity shortage issue and enlarge the electrical energy reserve margin but also to facilitate competitions among generators. The first generation IPPs were awarded licenses for five gas-fired power plants. The licenses for the second generation of IPPs were issued for five other gas-fired power plants from 1998-2004. Meanwhile, the third generation licenses of IPPs were awarded to two private coal-fired power plants. Despite this, the TNB still monopolizes the electricity market in terms of its transmission and distribution. Meanwhile, the Malaysian Government also planned to restructure its electricity supply industry in three phases to make it more efficient, transparent, equitable and more competitive. The first phase involves a multi- seller and a single buyer who have been in operation since 2001, while the second phase introduces a multi- buyer mode where a competitive bidding process is introduced for the electricity distribution sector. On the other hand, the third phase will then feature regional market transactions involving transfers between Peninsular and East Malaysia and within the ASEAN Grid countries. However, the plans for creating a fully competitive market were abandoned by the government in view of the California experience. The government instead, decided to adopt the Managed Market Model (3M) which emphasized improving the existing arrangements and customizing terms to suit local condition [5]. Therefore, MESI remains its electricity market with a single buyer which is based on the first phase of restructuring as shown in Fig. 1.

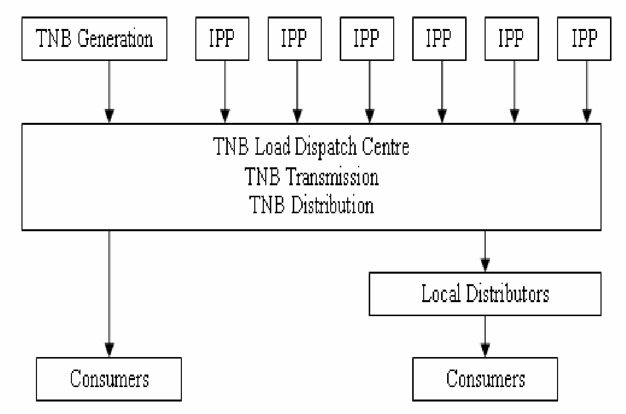


Fig. 1 Diagram of MESI structure; single buyer market.

The purpose of a single buyer is to equally divide power generation, transmission and distribution among IPPs and power plants of national electric power company and promoting fair competition [6]. In case of Malaysia, TNB plays the role as the power purchasing agency obliged to buy the electricity from IPPs. In return, the IPPs are being paid for the electricity delivered based on the power purchase agreement (PPA). Although IPPs were initially introduced to provide competition in general, the term under PPA in which these IPPs were introduced did not affect real competition in general. They were brought in on a basis of direct negotiation as opposed to competitive bidding. Moreover, this agreement provided guaranteed returns for the IPPs with very little risk borne by them over a 21-25 year tenure [7]. There are two types of payment in the PPA- capacity payment and energy payment. The capacity payment is paid for the availability for the plant to supply regardless of the amount of electricity usage. This payment is basically a method used for preventing long-term fluctuations in an IPP investment where its electricity is paid to recover a portion of its investment in the long run. On the other hand, the energy payment is paid for the electricity usage supplied by the IPPs. As a result of imbalance between generation and demand, TNB suffered massive profit erosion due to the agreement. Nevertheless, no effort or negotiation can further be done among the trading parties until the agreement period has expired.

Therefore, it is important for the energy regulator, i.e. Energy Commission (EC) to look forward in replacing the existing single buyer market with a more transparent and competitive market model. As planned in the second phase restructuring, the pool market model was initially identified as a possible model for the replacement since it could provide a competitive and transparent electricity market for the trading parties.

The application of this model, however could invite a lot of denials from both TNB and the IPPs if it is not implemented properly. For the IPPs, this may due to insecure incomes, especially for the generators with a higher-energy bid price which will have fewer opportunities to sell their output, especially during low load demand. Since there is no capacity payment mechanism in pool trading mode, some generators will not receive any revenue at certain hours. On the TNB side, majorities of the power plants are not efficient enough due to ageing. This could increase the marginal cost of production, and as a result the TNB has fewer opportunities to sell the output due to higher marginal price.

In addition, there are possibilities of having a market power exercise in a pool market model. For example, large power producer companies could monopolize the market by arranging several bidding strategies, which may affect the stability of electricity market and rise up the market risks [8]. For these reasons, it is important for EC to look into the effects of applying this market model, especially on the generator revenue adequacy issue.

The hybrid market introduced in this paper could be a possible market model to overcome aforementioned issue since it provides a better economic signal to the generators with firm participation in all trading periods.

## 3. Electricity market model

This section describes the basic concept and formulation of a single buyer market, pool market and the proposed market. The first two markets are initially designed to promote a competition environment, but some practical applications have shown the drawbacks of each model. The proposed market, on the other hand, is derived to overcome the shortcomings of the two market models.

### 3.1 Single buyer market

This market model is designed to encourage more investors, i.e. the IPPs to take part in Electricity Supply Industry (ESI). The IPPs also known as Non-Utility Generator (NUG) is an entity but not a public utility, which owns facilities to produce electric power. Many of the developing countries prefer to choose the single buyer market as the first step towards restructuring. The popularity of the single buyer market is due to less technical changes required, also several economic, and institutional factors. For example, the single buyer market helps to maintain a unified wholesale electricity price, which is simplifying the price regulation. However, it is suggested for a developing country to skip this stage and adopt a market model with multiple buyers immediately after unbundling as the single buyer model has major disadvantages, particularly in countries with weak or corrupt government and low payment discipline [9]. Theoretically, the existence of a number of IPPs can create competition between them and the local/public power producers and thus reducing the electricity price.

However, in reality the competition seems does not exist due to the Power Purchase Agreements (PPAs) signed between IPPs and the power purchasing agency. All power producers, including the local power producers and IPPs have to sell their output to the power-purchasing agency at an agreed purchase price. A power purchased agreements (PPAs) is a legal contract involving the generation and sales of electricity [10]. The purpose of the agreement is to avoid market risk. Many Asian, African and Eastern European countries prefer this concept because it is simpler and easier to apply. There are two types of payment that are included in the PPA; i) energy payment and ii) capacity payment. The energy payment can be mathematically expressed as

$$G_{EP\,i} = \left(P_{EGi} \times C_{EGi}\right) \quad (1)$$

Where $G_{EPi}$ is the energy payment for a power producer $i$, $P_{EGi}$ is the power output generated by $i$th power producer in MW and $C_{EGi}$ is the energy price offered by $i$th power producer in RM/MWh. Meanwhile, the capacity payment is normally calculated in monthly basis. For hourly basis, the mathematical equation for the capacity payment can be written as

$$G_{CP\,i} = \left(P_{Gi} \times C_{Gi}\right) \quad (2)$$

Where $G_{CPi}$ is the capacity payment for a power producer $i$, $P_{Gi}$ is the power capacity available by $i$th power producer in MW, and $C_{Gi}$ is hourly capacity price offered by ith power producer in RM/MW/h. Thus, the hourly revenue for a power producer $i$ can be presented as

$$G_{SB\,i} = G_{CGi} + G_{EPi} \quad (3)$$

Thus, the mathematical equation for total revenue for power producers will be

$$G_T = \sum_{i=1}^{k} G_{SBi} = \sum_{i=1}^{k} [\left(P_{Gi} \times C_{Gi}\right) + \left(P_{EGi} \times C_{EGi}\right)] \quad (4)$$

Where $k$ is the numbers of power producers involved, $G_T$ is the total generator revenue in RM/h.

The electricity trading that occurred between the buyer and seller for this market is depicted in Fig. 2. The choosing mechanism that would reflect which power producers will supply for the demand of the country is based on a merit order. This means that the least cost power producers will be able to sell their output first compare to the expensive cost power producer. The cost of generation is influenced by the fuel cost and the variable operating cost factor. However, as the local power producer is responsible in conducting the dispatch, this may influence them to choose their own power plant to deliver the demand.

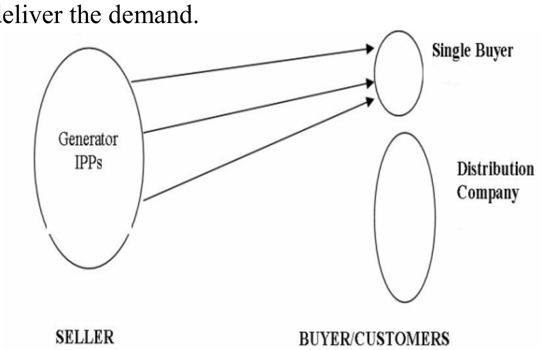


Fig. 2 Diagram of single buyer electricity trading.

### 3.2 Pool market

In a pool market, all energy supply is controlled and coordinated by a single pool market operator who is normally known as Independent Market Operator (IMO). The system operator is responsible in deciding the necessary actions to prevent violation of the grid constraints from occur [11]. All generators under a pool had to trade through IMO and follow the dispatch instructions based on the bid they submitted [12]. There are two main sides of entities participating in the market namely the producers/seller and customers/buyer. The IMO will consider the electricity bids and offers from these two entities to dispatch them in an economic manner depending on the submitted bidding price and MW available capacity [13]. This market model is depicted in Fig. 3. The seller and buyer do not directly interact to each other, but indirectly interact through the IMO.

Basically, the pool market operation can be divided into two stages [1]. The first stage is called unconstrained dispatch and the second stage is called security constrained dispatch. During unconstrained dispatch, the power producers or generators are placed in an ascending order according to their bid prices without considering any system constraints. A number of the least cost generators are selected for dispatching to meet system predicted demands.

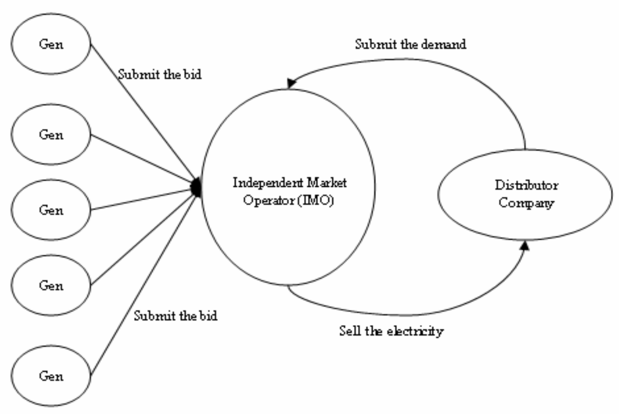


Fig. 3 Diagram of pool electricity trading.

The selected generators are called in-merit generators while the remaining generators are called out-merit generators. The bid price of the last dispatched generator determines the system marginal price (SMP). The SMP is determined by the point of intersection of supply and load curves in the bid price vs. generator power output graph as shown in Fig. 4. (ie. $SMP = \alpha_{G3}$ ). The SMP is the marginal cost of the marginal unit in the absence of transmission constraints. That is, the SMP is only determined from the generator's bids but independent of system physical constraints.

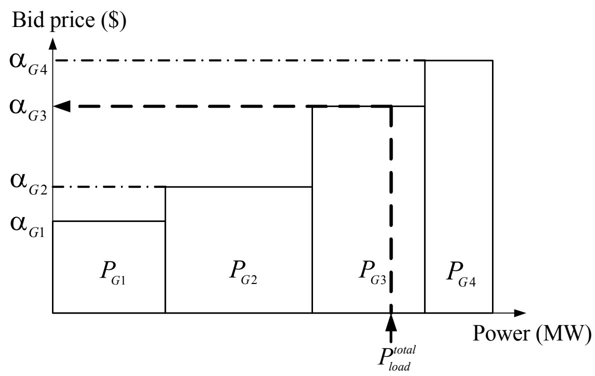


Fig. 4 Diagram of the aggregated supply curve from submitted bid price.

There are two market bidding strategies that may be adopted in the pool market [14]:

1) *One sided pool:* Generators submit bids and their available supply capacity. These bids are ranked in order of increasing price. Meanwhile, the demand curve is predicted to be a vertical line at the value of the load forecast. The highest priced bid that intersects with the demand forecast determines the market price, which is applied for the whole system.

2) *Two sided pool:* Consumers can submit offers specifying quantity and price and ranking these offers in decreasing order of price. For generators, the same condition as in the one sided pool applies. The intersection of the supply and demand curves represent the market equilibrium.

In this market, Pool Purchasing Price ($C_{PP}$) is the price that the IMO pays the generators for dispatching their power. The $C_{PP}$ is calculated as follows [15];

$$C_{PP} = SMP\,(1 - LOLP\,) + VOLL\,(LOLP\,) \qquad (5)$$

Where SMP is the system marginal price, LOLP is the loss of load probability, and the VOLL is the value of loss load. Therefore, the revenue for a power producer $i$ can be mathematically expressed as

$$C_{PM\ i} = \left(P_{PGi} \times C_{PP}\right) \qquad (6)$$

Where $P_{PGi}$ is the power capacity available by $i$th power producer in MW and $C_{PP}$ is the pool purchase price in RM/MWh which can be calculated as shown in (5). Thus, the total revenue for all power producers can be written as

$$G_T = \sum_{i=1}^{k} G_{PMi} = \sum_{i=1}^{k} \left(P_{PGi} \times C_{PP}\right) \qquad (7)$$

Where $k$ is the numbers of generators involved, and $G_T$ is the total revenue in RM/h. All in-merit generators will be paid based on $C_{PP}$ (uniform price) neglecting their initial bidding price. The domestic bidding strategies in pool trading may be influenced by the trade opportunities [16]. This market model would encourage generators to submit lower bidding price in order for them to be selected for dispatch. Moreover, these least expensive generators also will be able to get extra incomes during high demand. However, pool market is vulnerable to market power as the electricity price could go high and become volatile, especially at high load demand [17]. Some generators may seek for this opportunity to raise the market price by setting higher price on the marginal plant to reap profits [18]. In addition, the amount of SMP is dependent on demand and this has increased the possibility in market power exercise.

## 3.3 The Proposed Market

In the proposed method, it is suggested that the load demand is divided into two parts; base load demand and peak load demand. In the base load demand, the load is distributed to the generators based on the pro-rata basis. There is no competition among the generators at this level, and the generators will share this load proportional to their available capacity, i.e. generators with higher available capacity will have high percentage share of the base load demand. On the other hand, the remaining high load demand will be traded through competition of the energy bid price offered by each generator. Generator with a lower energy bid price has the priority to supply the remaining demand. The generator's payment for the base load demand would be based on the SMP while for the remaining load demand would be based their energy bid price. The MW level of base load demand will be determined from the daily load curve. The mathematical equation that represents each generator's contribution to the base load demand can be written as;

$$P_{Gibl} = \frac{P_{Gi}}{\sum_{i=1}^{k} P_{Gi}} \times P_{GTbl} \tag{8}$$

Where $P_{Gibl}$ is each generator share of base load demand, $P_{Gi}$ is the available capacity of a generator $G_i$, and $P_{GTbl}$ is the identified base load demand. The revenue during base load sharing, $G_{BLi,}$ can be calculated by replacing the SMP and $P_{PGi}$ value in equations (5) and (6) for base load demand instead of full demand. The LOLP and VOLL value in equation (5) were set at 1/365 and 10000 respectively.

The existence of base load sharing approach in the proposed market ensures the participation of generators for all trading period. This market could also reduce the market power exercise as a part of the generators' available capacity has been used to supply the base load demand. This reduces the ability of least-cost generators to monopoly the pool market with certain bidding strategies.

The revenue equation for the remaining load demand which is traded through bidding competition can be written as

$$G_{RLi} = P_{Ri} \times C_{EGi} \tag{9}$$

Where $P_{Ri}$ is the remaining demand, and $C_{EGi}$ is each generator bid price. Thus, the generator revenue for the proposed market can be written as

$$G_{HMi} = G_{BLi} + G_{RLi} \tag{10}$$

Thus, the mathematical equation for total revenue for all power producers will be

$$G_T = \sum_{i=1}^{k} G_{HMi} = \sum_{i=1}^{k} [(P_{Gibl} \times C_{PP}) + (P_{Ri} \times C_{EGi})] \tag{11}$$

## 4. Results and Discussion

A case study is discussed using Malaysia's electricity load demand. Fig. 5 consists of four load profile curves on weekday, Saturday, Sunday and public holiday that will be considered as an hourly load demand the IPPs must met for this case study. 14 chosen IPPs represent the generating units in the electricity dispatch system.

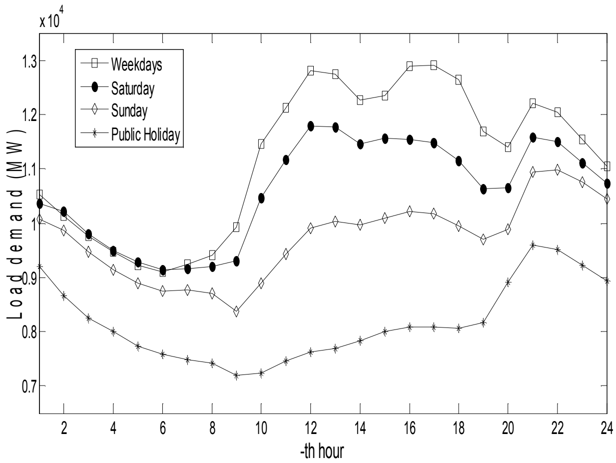


Fig. 5 Diagram of load profile for Peninsular Malaysia.

Since the monetary values involved in the study are confidential, estimated values are being used instead. The case study analysis used Malaysian ringgit as the currency. Table 1 shows the details of the available capacity and bid price of the IPPs. It can be noticed that bid price of the IPPs varies from one generator to the others. This variation is due to the fuel source that the generators used for generation. For instance, the energy price for the combined cycle plant should be lower from the open cycle and coal plant. Coal, natural gas, diesel and fuel oil are non-renewable sources used by most of the power plants in Malaysia [4].

Table 1 Details on the IPP available capacity and bid price.

| *No* | *Independent Power Producers (IPP)* | *Available Capacity (MW)* | *Bid Price (RM/MWh)* |
|---|---|---|---|
| 1 | Panglima Power Sdn. Bhd. | 720 | 180 |
| 2 | GB3 Sdn. Bhd. | 640 | 195 |
| 3 | Pahlawan Sdn. Bhd. | 322 | 195 |
| 4 | Teknologi Tenaga Perlis Consortium Sdn. Bhd. | 650 | 210 |
| 5 | Prai Power Sdn. Bhd. | 350 | 220 |
| 6 | Kapar Energy Ventures Sdn. Bhd. | 2420 | 225 |
| 7 | YTL Power Generation Sdn. Bhd. | 1170 | 225 |
| 8 | Genting Sanyen Power Sdn. Bhd. | 740 | 225 |
| 9 | Port Dickson Power Sdn. Bhd. | 440 | 235 |
| 10 | TNB Janamanjung Sdn. Bhd. | 2070 | 240 |
| 11 | Powertek Berhad | 440 | 240 |
| 12 | Segari Energy Ventures Sdn. Bhd | 1303 | 255 |
| 13 | Jimah Energy Ventures Sdn. Bhd. | 1400 | 285 |
| 14 | Tanjung Bin Power Sdn. Bhd. | 2100 | 300 |

The bid price and available capacity for the IPPs are being stacked from the least price up to the highest one to form a supply curve as shown in Fig. 6.

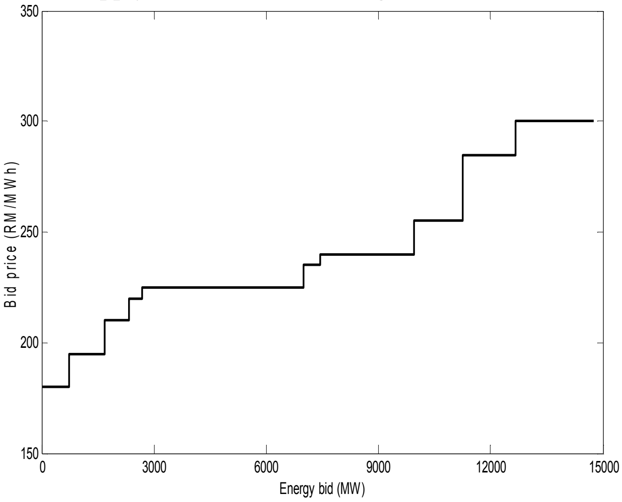


Fig. 6 Diagram of the aggregate supply curve from 14 IPPs' capacity available and bid price.

For the proposed market model, the base load demand for weekday, Saturday, Sunday and public holiday are at 9105 MW, 9135 MW, 8376 MW, and 7197 MW respectively. Fig. 7 shows typical load demand profile for weekday with the base load line at 9105 MW. The SMP at base load demand can be determined from the aggregated supply curve in Fig.6. For weekday, Saturday and Sunday base load demand; the SMP was RM 240. The SMP for base load demand on public holiday was RM 235. The remaining capacity which is above the base load line is allocated for bidding competition. Generator who submits a low bid price usually manages to grab the opportunity to supply the remaining demand.

For example on a weekday, the peak demand was 12900 MW. IPP1 manages to supply all 720 MW of its available capacity through both base load sharing and bidding. 444 MW was determined using base load sharing equation (8) and paid by multiplying the MW with the SMP of RM 240. The remaining 276 MW which supplied the remaining demand is paid using equation (10) with its own energy bid price of RM 180. The lowest demand worth of 7197 MW occurred on public holiday. At this hour, IPP14 as the most expensive generator still managed to supply 1024 MW through base load sharing with SMP of RM 235. IPP14 would not participate at all at this hour if the pool market is applied instead of the proposed market. Cheaper generators might end up with 100% capacity contribution from both base load sharing and bidding generation. Nevertheless, the expensive generators will not lose the opportunity to generate even though it is only for the base load sharing.

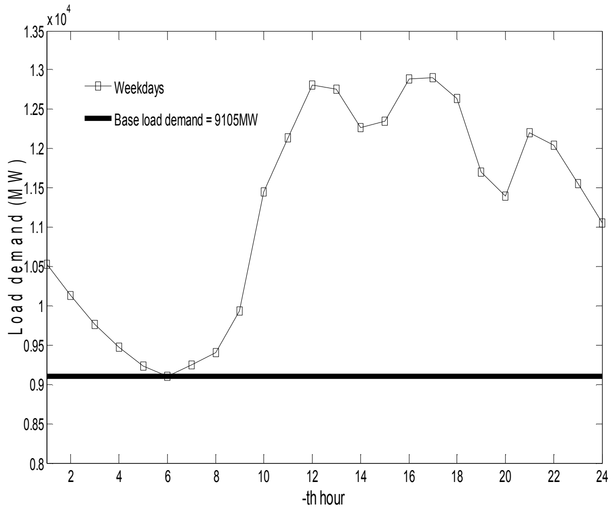


Fig. 7 Diagram of load demand curve on weekday.

The other merit to be highlighted from the proposed market is, that the generator efficiency is continued at the sufficient level despites the base load sharing mechanism.

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Using equation (8), each IPP averagely contributes 62% of its available capacity to the base load demand on weekday and Saturday, 56.8% on Sunday and 48.8% on public holiday. This percentage is only for base demand sharing excluding the percentage for bidding competition of the remaining demand and does not reflect the efficiency of each IPP. As each IPP consists of the different number of turbines, the efficiency of the IPP depends on the load capacity percentage of its turbine. Even though the power plant is not running at its 100% capacity as in the pool market, the proposed market ensures the capacity proportion is divided efficiently for all turbines. Therefore, during the base load sharing, the efficiency for each IPP is kept at the adequate level. For example, IPP14 consists of three turbines. During maximum load demand, two turbines operated at 92.86% of its capacity while during lowest load demand with one turbine operated, the efficiency is at 90% of its capacity. By using the proposed market, all IPP are able to maintain the turbine's load capacity percentage averagely at 90% even during the lowest load demand sharing on public holiday.

Table 2 The percentage of IPPs' total hour power contribution from pool and proposed market.

| | Weekday | | Saturday | | Sunday | | Public holiday | |
|---|---|---|---|---|---|---|---|---|
| Generator | Pool | Proposed | Pool | Proposed | Pool | Proposed | Pool | Proposed |
| IPP1 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| IPP2 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| IPP3 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| IPP4 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| IPP5 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| IPP6 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| IPP7 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| IPP8 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| IPP9 | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| IPP10 | 100% | 100% | 100% | 100% | 100% | 100% | 88% | 100% |
| IPP11 | 79% | 100% | 75% | 100% | 63% | 100% | 4% | 100% |
| IPP12 | 71% | 100% | 71% | 100% | 46% | 100% | 0% | 100% |
| IPP13 | 58% | 100% | 33% | 100% | 0% | 100% | 0% | 100% |
| IPP14 | 17% | 100% | 0% | 100% | 0% | 100% | 0% | 100% |

The shortcoming of, the pool market is that it does not permit all IPPs to participate in the trading during low load demand. The low cost IPP receives more benefit from the trading since they are able to participate in all trading periods. As shown in Table 2, only ten IPPs are fully participating in the weekday trading with 24 hours power contribution. The last remaining four IPPs could not participate in the most trading hours unless the load demand is reached to the point that requires their participation. For instance, the IPP11 could participate 19 hours in the pool trading during weekday, and the participation period is reduced to 18 hours, 15 hours and one hour on Saturday, Sunday and public holidays. This participation hour is much better compared with IPP12 and IPP13, since they can only participate for 17 hours and 14 hours during weekday. On the other hand, the IPP14 could not participate in a weekend and public holiday trading since the load demand is far less from the point that requires the IPP14 load contribution.

Meanwhile, in the proposed market, all IPPs are able to participate in the trading even though the load demand is low. The existence of the base load sharing approach in the proposed market permits the most expensive cost power producer, IPP14 to fully participate in the weekday trading compared to the pool market with only four hours of trading participation.

Figs 8, 9, 10, and 11 show the comparison of hourly revenue for each 14 IPPs for pool and proposed market models on weekday, Saturday, Sunday, and public holiday respectively. The significance of the proposed market is clearly observed during the low load demand. Without considering the proposed market, expensive generators such as IPP11, IPP12, IPP13 and IPP14 could not get revenue on public holiday because the total maximum demand at that time, which is approximately 9600 MW, is enough to be fulfilled by 12 IPPs. It is even worse for IPP14 which suffers zero revenue not only on public holiday but also on Saturday, and Sunday. It can be clearly observed that the proposed market guarantees revenue for all IPP, although in most cases, the generator revenue received from this market l is lower than the pool market.

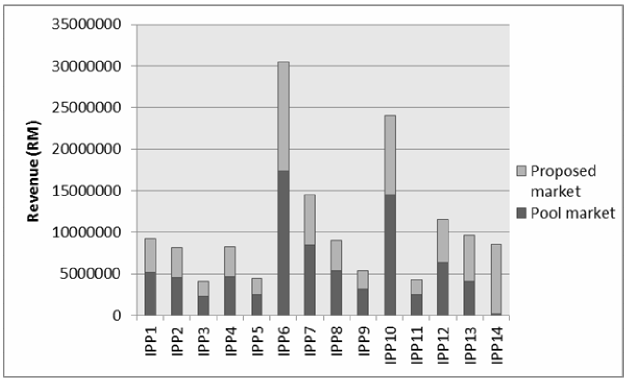


Fig. 8 Diagram of IPP revenue from pool and proposed market on a weekday.

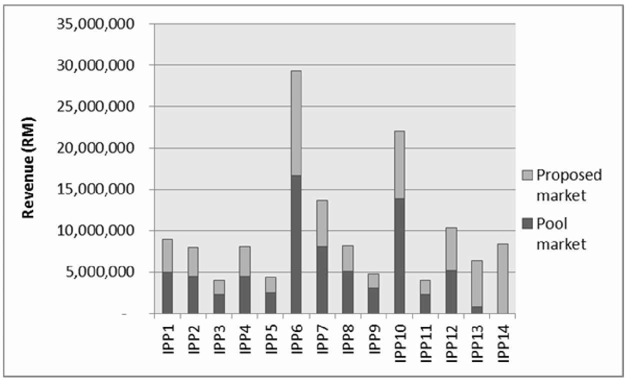


Fig. 9 Diagram of IPP revenue from pool and proposed market on Saturday.

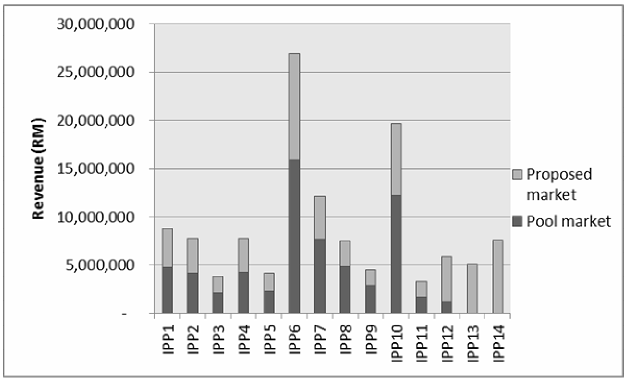


Fig. 10 Diagram of IPP revenue from pool and proposed market on Sunday.

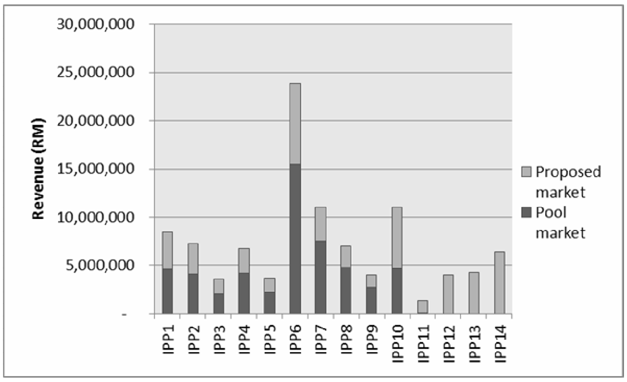


Fig. 11 Diagram of IPP revenue from pool and proposed market on public holiday.

Figs. 12, 13, 14 and 15 shows the total hourly revenue of 14 IPPs resulted from both pool and proposed markets for weekday, Saturday, Sunday and public holiday respectively. On a weekday, it can be seen that at low load demand, the generator revenue for both pool and proposed market are quite similar. However, when the load demand is high, the generator revenues under pool market are much higher than the proposed method. This is due to the increasing value of SMP, which produced higher pool purchasing price $C_{PP}$ to be paid to the IPPs. When the proposed market is applied, the $C_{PP}$ value is reduced because base demand is considered for every hour.

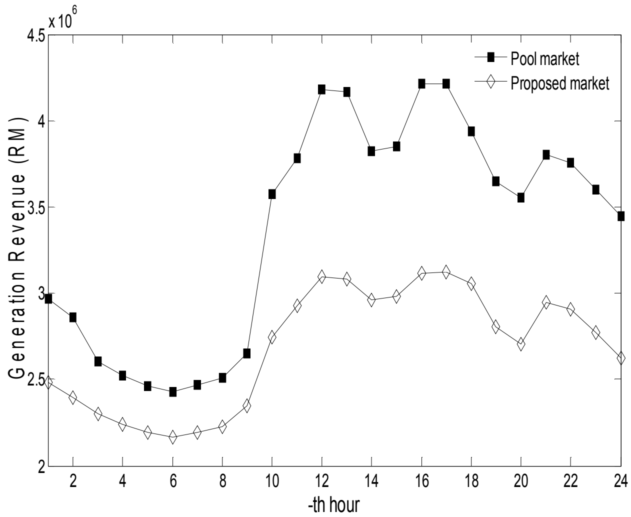


Fig. 12 Diagram of total generator revenue at each hour for pool and proposed market (Weekday).

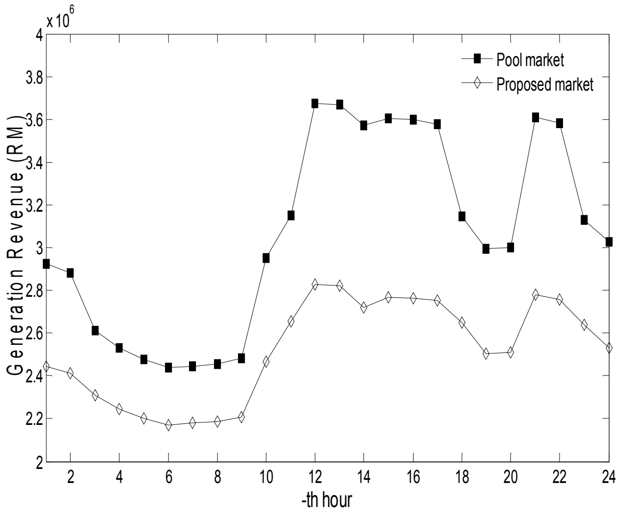


Fig. 13 Diagram of total generator revenue at each hour for pool and proposed market (Saturday).

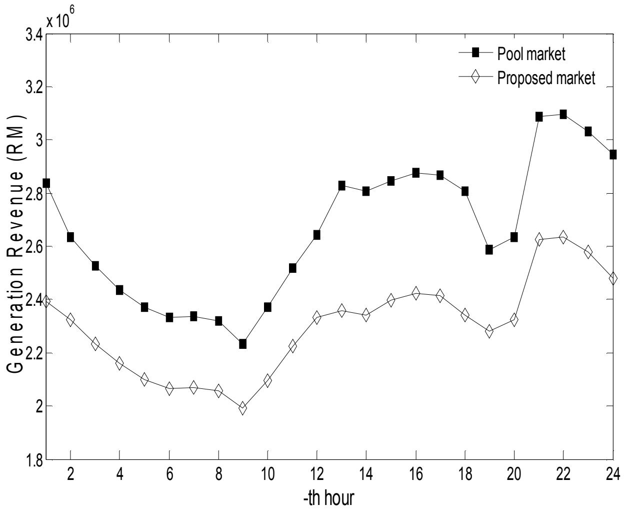


Fig. 14 Diagram of total generator revenue at each hour for pool and proposed market (Sunday).

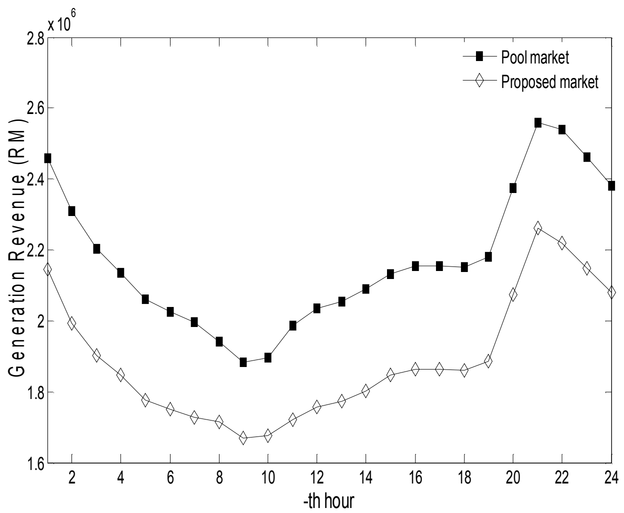


Fig. 15 Diagram of total generator revenue at each hour for pool and proposed market (public holiday).

Table 3 shows the total generator revenue for pool and proposed market. It can be seen that the total generator revenue for the pool market model is higher than the proposed one. However, the differences are not much and the fact that it is lower during the weekend is considered. For instance, in the weekday, the difference between these market models is 13%, but it reduces to 10%, 4% and 3% for Saturday, Sunday and the public holidays respectively. On the other hand, in the proposed market, each IPP is being protected in terms of its revenue as each one of them shares the base load demand and gets satisfactory revenue from it. This situation will then produce a win-win situation for all parties involved in the trading.

Table 3 Details on the IPP total revenue from pool and proposed market.

| Load profile type | Pool market (RM millions) | Proposed market (RM millions) |
|---|---|---|
| Weekday | 81.01 | 70.51 |
| Saturday | 73.53 | 66.84 |
| Sunday | 63.97 | 61.13 |
| Public holiday | 52.17 | 50.45 |

## 5. Summary

This paper proposed a hybrid market model to satisfy the generator revenue adequacy under competitive electricity market environment. The result from the case study has shown that the proposed market has merit over the pool market in providing fair generator revenue over trading hours. It can be observed that at the low demand, the pool market cannot guarantee hourly generator revenue for expensive generators. Some of the IPPs might lose their revenue because of non-participation in the trading. On the other hand, with the proposed market, all IPPs have equal opportunities to participate in the trading and receive some revenue for their contribution in base load demand. Moreover, the efficiency of the power producer is always kept at the adequate level.

In conclusion, the proposed market successfully overcomes the shortcomings of the existing single buyer market due to capacity payment obligation and the pool market, in the context of guaranteed revenue remuneration for the generator. The introduction of the base load demand sharing approach in the proposed market ensures the participation of all IPPs in the hourly trading period. The proposed market is believed to be effective if used by the Electricity Supply Industry in developing countries as a first step of introducing a competition in their electricity market.

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