

Aequero Comments on IPP Bid Solicitation Conference and Solicitation Guidelines

Aequero would like to thank the Ministry of Energy (“MOE”), the Energy Planning and Policy Office (“EPPO”) and its advisors for preparing the Discussion Draft of the IPP Bid Solicitation Guidelines (“Solicitation Guidelines”) and related documents and for organising the preliminary IPP Bid Solicitation Conference held on 15 December 2006 (“Solicitation Conference”) to obtain the input from the international investor community with respect to the proposed IPP solicitation.

We would like to take the opportunity to provide our comments on the IPP Solicitation Guidelines and the proposed IPP solicitation process. We have also taken the liberty of making some suggestions with respect to the overall strategic approach and opportunities available to the MOE that may assist the MOE in achieving its objectives of (a) diversifying Thailand’s energy mix, (b) achieving energy security and (c) facilitating a greater participation of renewable energy (“RE”) within Thailand’s energy mix. Our comments contained herein are not intended to be exhaustive; rather, the comments focus on the key issues raised within the Solicitation Guidelines and those that we believe are relevant to the present IPP solicitation process.

References herein to section numbers are references to the relevant section of the Solicitation Guidelines unless otherwise indicated. References to slide numbers are references to the slides presented during the Solicitation Conference by the advisors to EPPO. References to the Standard PPA are to the drafts dated 1 December 2006 made available on the Energy for Environment Foundation (“EFE”) web site.

1. **Power Development Plan:** It is important that a credible Power Development Plan (“PDP”) be developed for determining and supporting, inter alia, the capacity to be solicited under the IPP Bid Solicitation.

EGAT has an important role in providing input in the PDP preparation process. However, the PDP should not be prepared by EGAT as it may be perceived that EGAT has a potential conflict of interest. Rather, the PDP should be prepared by an independent party, taking account of input from all stakeholders.

The PDP should address all sources of electricity supply, including generation by EGAT, Independent Power Producers (“IPP”), Small Power Producers (“SPP”), Very Small Power Producers (“VSPP”) and RE projects as well as imported generation. In this regard, if the MOE is serious about the targeted participation of RE in Thailand’s energy mix this should be reflected in the PDP.

2. **Integrated Approach to Policy Development:** As a corollary to comments on the PDP and Energy Mix (see 3 below), it is critical that MOE take an integrated approach to policy development to provide an appropriate policy platform to achieve the broader sector objectives.

We have included at Appendix A a conceptual map of the power generation sector for independent power producers (including, IPPs, SPPs, VSPPs and RE projects) in Thailand.

3. **Energy Mix:** During the Bid Solicitation Conference His Excellency, Dr. Piyasvasti Amranand, Minister of Energy indicated that 74% of Thailand’s

generation in 2005 was contributed by gas-fired power generation¹. The Minister confirmed that it was the MOE's objective to diversify the energy mix in Thailand in order to reduce the over-reliance of the power sector on gas-fired generation.

In particular, the Minister noted the desire to award approximately 40% of the capacity available to IPPs (the precise capacity to be confirmed – see Item 11) to bidders proposing clean coal technologies. This is supported at Section 4.6 of the Solicitation Guidelines which indicates that the MOE “...will allow a preference during bid evaluation for projects that utilize as their primary fuel/energy resource...imported and domestic coal used in plants adopting state-of-the-art clean coal technologies...”

The resistance by local communities and Non-government organizations (“NGO”) in Thailand to coal fired generation is well documented and remains relevant². For this reason it may be necessary for the MOE to adopt a different approach to the IPP solicitation process for coal projects (see Item 8 below).

4. **Renewable Energy:** As part of its strategy to diversify Thailand's energy mix, the MOE has set a target to achieve 8% of Thailand's overall generation capacity from RE sources by 2011³. Moreover, at the 23rd ASEAN⁴ Energy Ministers Meeting held in Siem Reap, Cambodia on 13 July 2006 the ASEAN Energy Ministers committed to an “...objective to increase the share of renewable energy in power generation in the region to ten per cent by 2010.” These targets should be reflected in the PDP.

Moreover, the MOE should develop an appropriate policy and related RE power purchase agreement (“PPA”) to encourage investment in RE projects in order to fulfill its objectives in this regard as well as its overall objective to diversify the energy mix in Thailand. The proposal to delay the solicitation “...for IPP-supplied capacity, based exclusively on renewable energy...” until after the IPP solicitation will surely mean that the MOE will comprehensively fail to meet its RE objectives and is inconsistent with (i) the development of a comprehensive (independent) PDP (see Item 1) and (ii) an integrated approach to policy development (see Item 2).

RE has the potential to make a material energy supply contribution to the Thai energy mix; and can be achieved on a larger scale, whether on an exclusive RE basis or on a co-firing basis (see Item 7). Current discussions and policy announcements regarding RE appear to relegate RE to the VSPP category (<10MW). Aequero believes that this marginalises RE's potential contribution, effectively relegating it to an insignificant and scale-inefficient after-thought in the overall energy mix⁵. Given the limited options available to Thailand to diversify energy sources, this approach seems incongruent with MOE's goals.

¹ If EGAT is to develop 4 x 700 MW of gas-fired power plants (2,800 MW, in aggregate) in the period 2007-2010 this will result in a significantly greater dependence by Thailand on gas-fired power generation.

² By way of example, there was a swift negative response to EGAT's proposal to accelerate its plan to develop a coal-fired project in Thap Sakae, Prachuap Khiri Khan following the coup in Thailand in September 2006.

³ The Department for Alternative Energy Development and Efficiency (“DEDE”) has indicated that this objective may be amended to 6% of delivered energy.

⁴ ASEAN: Association of South East Asian Nations.

⁵ There is a potential for larger-scale RE plants to be effective contributors to the overall energy mix in Thailand. But scale is the key. Plant efficiencies in excess of 30% can be achieved for larger scale projects (as opposed to efficiencies of 18-25% for typical small-scale RE plants). Further,

We have attached as Appendix B for your consideration the Renewable Energy Policy Principles that AeQUERO has developed. These were submitted to the His Excellency, the Minister of Energy on 4 December 2006.

During the Solicitation Conference the advisor to EPPO suggested that the rationale for excluding RE from the solicitation process was that the MOE was seeking to solicit for base load capacity and RE projects could not provide base load capacity. This is not correct. Well structured RE projects - in particular, biomass projects - with appropriate policy support may provide base load capacity and should be encouraged.

However, the complexity and special structuring requirements of RE projects may not naturally fit with a solicitation process in the form envisaged for the IPPs. An ongoing solicitation process similar to that currently operating for SPPs may lend itself more readily to RE projects.

5. **Evaluation - Full Cost Accounting:** Present evaluation methodologies do not take account of the full cost of delivered energy from a generation source; rather, only the financial / economic costs are evaluated. This approach does not account the social and environmental costs / benefits of projects. Projects that can generate economically cheap electricity at the cost of the environment and the local community tend to be advantaged by an evaluation based solely on price.

The EFE has proposed a 'Full Cost Accounting' approach to the analysis of energy generation projects. A copy of the formula posited by EFE is provided below⁶. Aequero endorses the approach of EFE.

Full Cost Accounting	=	Accounting Costs + Environmental Costs + Economic and Social Costs
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A perennial challenge to this approach, however, is the way in which to account non-accounting costs associated with the environmental, economic and social benefits / costs associated with a project. An appropriate methodology needs to be developed by the MOE, and the government of Thailand generally, in order to fully assess the impact of all projects in the energy sector. The methodology will need to be objective and consistently applied.

EFE has further proposed that the 'Polluter Pays Principle' be applied in respect of environmental costs. This proposal has merit in that it may redistribute income from projects that have a negative impact on the environment to those that will have a lesser impact and, thus, encourage sustainable socially responsible and environmentally-friendly investment in the energy sector. For example, this may facilitate the encouragement of RE through the application of levies on emissions of NO_x, SO₂, CO₂ and CH₄ which can then be used to supplement RE tariffs through a Feed-in Tariff mechanism (refer Appendix B, Part B).

6. **Evaluation – Marginal Cost of Fuel:** Further, in evaluating Thailand's future energy mix choices, consideration should be given to the marginal cost and price volatility of gas, coal and other fuel supply alternatives. This is particularly relevant in the context of future gas projects which are likely to rely on imported

development costs for larger scale projects can be spread over a broader investment, reducing this cost component on a per kW basis.

⁶ Source: Energy for Environment Foundation Newsletter Volume 4, Issue 4 October 2006.

gas, either by way of pipeline gas or imported LNG⁷ (see also Item 9). In this regard it may be expected that the marginal cost of gas will trend upwards reflecting a shifting paradigm in international gas and hydrocarbon markets.

An independent consultant should be engaged to provide realistic cost estimates for gas and coal prices over the project period, taking account of international supply and demand dynamics that will influence prices over this period.

7. **Co-firing:** From a strategic perspective, the MOE may wish to give consideration to encouraging co-firing projects that use, for example, a mix of coal and biomass. This may achieve the dual objective of diversifying Thailand's energy mix and increasing the role of RE in Thailand's energy mix. Such projects may include built-in Community Development Programmes through the participation of the local community which may also assuage concerns about the use of coal.

There is presently no policy mechanism in Thailand that would provide for such 'hybrid' projects.

8. **Solicitation for Coal Projects:** As noted above there has historically been considerable resistance to coal project in Thailand by local communities and NGOs. This represents a significant risk to potential IPP bidders, highlighted by the final outcome of the 1994 solicitation where two projects that had originally been awarded as coal projects were ultimately relocated and changed to gas-fired projects.

An alternative approach is for the MOE to undertake a separate solicitation for one or more coal projects in respect of which site selection is made and the EIA / public disclosure process is commenced / developed by the MOE (and / or an appropriate government agency, for example, the MOE working in conjunction with the Ministry of Natural Resources and Environment ("MONRE")).

Education is a key component in gaining acceptability of 'clean coal' technologies. The MOE and MONRE should jointly take a leading role in establishing, publicising and promoting the environmental standards to which new 'clean coal' plants would be held.

On the face of it, the Government would seem better placed to address the environmental and social aspects of promoting a coal project than the private sector, including designing the very specific Community Development Programme that such a project would require. The MOE may then obtain reimbursement from the successful bidder for costs incurred in respect of land acquisition and permitting, including environmental permitting, as well as a commitment from that bidder to honour the agreed Community Development Programme (see also Item 11).

9. **Security of Gas Supply:** There is some concern regarding the long term security / availability of gas supply from existing resources available to Thailand. The Solicitation Guidelines propose that bidders may propose "...*primary fuel / energy resources...[from] Natural gas sources outside Thailand including LNG.*" Given the scale limit imposed on projects it is difficult to envisage that a bidder could realistically propose a gas-fired project with an associated gas supply chain (pipeline or LNG receiving terminal) at an economically competitive level.

In this context, bidders proposing gas plants would benefit from a clear indication of gas availability for the full term of the GSA, matching the term of the PPA.

⁷ LNG: Liquefied Natural Gas.

10. Cross-border IPP Projects: A possible alternative to the importation of gas and the challenges of siting a coal project in Thailand would be to open the solicitation process to cross-border IPPs located in Laos, Cambodia or Malaysia. These projects would be required to comply with Thai environmental standards and grid code requirements in addition to those operating in the projects' host country. Appropriate arrangements would be necessary to address the cost of transmission facilities.

11. Solicitation Schedule and Scope: The latest available version of the PDP⁸ suggests capacity additions of approximately 1,600 MW per annum during the period 2011-2013 i.e. an aggregate of 4,800 MW. If deductions are made for (i) three Laos projects expected to achieve COD⁹ during this timeframe¹⁰ at an approximate aggregate of 1,350 MW, (ii) 10% of capacity additions to come from RE¹¹ (480 MW), including from VSPPs, and (iii) an arbitrary 10% of capacity additions to come from SPPs (480 MW), this would leave only approximately 2,500 MW available for IPPs i.e. three projects (units) of approximately 800 MW to be commissioned during the 2011-2013 period or approximately one project (unit) in each year.

The bid solicitation schedule provides for a relatively long timeframe between bid submission and commissioning of the latter project(s) in 2013 (Exhibit A at the back of the Solicitation Guidelines suggests SCOD¹² targets 2011-2013)¹³. This may require bidders to absorb open positions on EPC contract price, financing and other costs increasing the risk post-project award.

One approach, in this regard, would be to allocate the latter SCOD target(s) to a coal project(s) and running this under a separate bid process as recommended at Item 8 (Solicitation of Coal Projects).

However, allocation of the latter SCOD slot(s) to a coal plant(s) will serve to exacerbate the short term over-dependence on gas, which would seem to be contrary to the objectives of the MOE. As stated in Item 8, the Government needs to take the lead in creating the conditions for a new 'clean coal' plant(s) to be successfully implemented. We expect that this will take time, which tends to support a separate solicitation process.

12. SOE Policy: The proposal to open the bid solicitation only to SOEs¹⁴ through their subsidiaries in which SOEs, in aggregate, hold less than 50% of the equity seems fair on first blush. However, a lingering perception may exist among bidders that do not have SOE participation that such SOE related party bidders have an advantage. This may discourage participation by bidders that do not have SOE participation among their consortia, particularly given the relatively small amount of capacity being solicited (see Item 11).

⁸ Source: EPPO (from Thailand Load Forecast Subcommittee, dated 27 July 2006).

⁹ COD: Commercial Operation Date.

¹⁰ Namely, Nam Ngum 2 and 3 and Nam Theun 1

¹¹ This is consistent with the objective agreed by the ASEAN Ministers, referenced at Item 4.

¹² SCOD: Scheduled Commercial Operation Date.

¹³ It is noted that the "Critical Schedule up to Commercial Operation" set out in Slide 10 indicates a period of 30 months from Financial Close / Notice to Proceed to the SCOD: CCGT plant in October 2011 and 42 months to the SCOD: Coal-fired Plant in October 2012, these dates, respectively, 48 months and 60 months after Bid Submission.

¹⁴ SOE: State-Owned Enterprise.

13. Community Development Programmes: We applaud the initiative of the MOE to address the concerns of local communities through the inclusion of an obligation on bidders to provide for a Community Development Programme under the Solicitation Guidelines.

The Solicitation Guidelines suggest that such programmes “...will increase the acceptability of all power plants, but especially coal plants, to host communities.” While this may be the outcome there is no assurance to bidders that such Community Development Programmes will indeed result in greater acceptability of their power plant to the local community. A connection between the management of these funds and the project developer may assist in this regard.

It will be fundamentally important for the success of this initiative that funds allocated to the Community Development Programme make their way to benefit the host community at large and not a small group of individuals / special interest groups.

Note that Schedule 25 of the Standard PPAs provides that an initial THB10,000,000 be deposited into each of the four funds prior to issuance of Notice to Proceed / commencement of land clearing at site. This equates to THB40,000,000 across the four funds which represents THB50 / kW for an 800 MW plant, not THB30 / kW as indicated at Slide 32. Perhaps the reference at Schedule 25 should be to an amount per kW of installed capacity (THB7.5 / kW per fund?) which will account for different project scales e.g. 800 MW vs. 1,600 MW.

We also note that the proposed approach to the Community Development Programmes, in particular the requirement to establish four funds, is relatively rigid and does not provide for imaginative approaches by IPP bidders to address the needs of individual local communities, nor does it promote commitments beyond the minimum levels indicated.

We note that not all host communities will have the same needs. One approach, in this regard, would be to solicit a Community Development Programme ‘business plan’ from bidders as part of the bid submission. This approach has the merit of encouraging bidders to get to know and thoroughly think through the issues relevant to their host community. One caveat, in this regard, is that the business plan will need to incorporate flexibility to accommodate change and/or evolution as more information becomes available about the host community’s circumstances (bearing in mind the relatively short bid time frame).

The situation is not helped by the binary evaluation (pass-fail) to be employed in this regard. We note that the Solicitation Guidelines state at Section 9.1 that “*In the case of coal-fired projects, the quality of the community development program will be awarded greater weight in the overall bid evaluation than will be allowed for CCGT¹⁵.*” This contemplates a qualitative evaluation which is not consistent with a pass-fail approach. When this issue was raised with the advisors to EPPO during the Solicitation Conference it was verbally confirmed that the pass-fail approach would be applied to the Community Development Programme. Clarity on this point would be welcome.

The development of ‘Full Cost Accounting’ evaluation criteria (refer Item 5) would enable greater flexibility to potential bidders which may lead to greater community involvement and acceptability of projects.

¹⁵ CCGT: Combined-Cycle Gas Turbine.

Aequero's view is that the most powerful Community Development Programme is the potential for IPP bidders / projects to bring employment and income opportunities to host communities. Unfortunately, the typical gas or coal-fired power plant tends to bring few job opportunities and the perception, particularly for coal projects, of adverse environmental impacts.

As noted at Item 7, and given that the Community Development Programme appears to be particularly directed at gaining acceptance for coal projects, co-firing may be one approach to balancing perceived adverse environmental impacts with real benefits for the local communities.

14. Community Development Programme – Impact on Plant's Standing in Economic Merit Order: It is clear that the imposition of the Community Development Programme on bidders in the present IPP solicitation will disadvantage these project developers vis-à-vis existing generators in relation to their standing in the economic merit order. Consideration should be given by MOE to maintain a 'level playing field' in this regard.

15. Availability Payment (Section 6.1): There appears to be an error in drafting. Presumably financing and interest rate swap costs of the power plant itself are also intended to be covered (not just those relating to the new transmission facilities).

16. Evaluation Process (Section 8.3): The evaluation criteria that will be used in evaluating proposals in respect of technical and financial aspects should be clearly set out in the Solicitation Guidelines to be issued with the Request for Proposals ("RfP") and should remain unchanged. The suggestion that certain modeling parameters may be changed after bids have been submitted may tinge the solicitation process with questions as to transparency and the potential perception of an anti-competitive advantage accruing to winning bidders.

In the interests of transparency we would recommend that bidders that pass the technical evaluation (phase 1) be invited to a 'bid opening' conference during which all technically qualified bidders' financial proposals are opened and ranked, subject to checking and approval by the MOE and relevant Government agencies.

Clarification questions during the bid evaluation process, wherever possible, should be issued and responded to in writing. This provides a clear 'audit trail' in the event of allegations of anti-competitive advantage.

Given the desire to diversify the energy mix (see Item 3), it would seem appropriate to evaluate gas and coal plants separately whether or not coal plants are solicited separately (see Item 8).

17. Evaluation Process - Multi-Date Bids and Project Deferral (Slide 14): Slide 14 states that bidders "...may propose three [CODs] at least three months apart with related tariffs for each date." Will these multi-date proposals be treated as separate proposals or as one proposal with COD-price alternatives i.e. if two or more of the multi-date proposals were ranked the most competitive would more than one plant be awarded to that bidder?

Slide 9 states that MOE "...will mitigate excess capacity risk by requesting bidders to

- Provide MOE with a fixed price option to extend the bidder's [SCOD] by up to 24 months

- *Allow the MOE to exercise the option any time prior to the bidder's proposed [SCOD]*

Slide 9 further states that *"The option price will be a factor in selecting winning bidders."*

This is likely to be difficult to price in practice given (i) the time between bid submission and the bidder's proposed SCOD and (ii) the different scenarios that may need to be contemplated by that option e.g. the option may theoretically be exercised during the financing phase / pre-Notice to Proceed, during the construction phase or during the commissioning phase, all of which will have different commercial implications for the bidder.

An alternative, proposed during the Solicitation Conference, would be to agree a formula for the tariff revision in the event that the option is exercised, although we note that such an approach would require bidders to disclose information concerning their bids that may be regarded as commercially sensitive.

It is also unclear how the MOE intends to evaluate the option price as a factor in evaluating winning bidders. Clear evaluation criteria should be made available to bidders in this regard.

MOE may avoid the need for this provision within the RfP by focusing on the development of a realistic PDP, incorporating all potential alternatives for energy supply (see Item 1). To the extent that demand ticks up e.g. from a low / medium to high scenario, a reserve gas plant could potentially be tendered as a supplement to the present RfP process – given the relatively short bid preparation-to-commissioning timeframe that could be achieved (particularly, in open cycle) assuming RfP documentation is already available for issuance i.e. from the present solicitation process.

18. Evaluation Process – Bid Bond Validity (Section 8.4; Slide 14): Slide 14 indicates that a bid bond validity of 9 months is required from the bid submission date while Section 8.4 states that a period of 12 months is required. It is recommended that MOE maintain the bid bond validity until PPA signing, a period indicated to be 12 months after bid submission.

19. Foreign Exchange Risk (Section 10.3; Slides 28 and 29): Bidders are being asked for a reduced level of foreign exchange indexation, which is appropriate given the greater depth of the Thai Baht debt market.

The proposed \pm THB2 'deadband' around the Reference [Exchange] Rate represents a potential movement of approximately \pm 5.5% from the current exchange rate (US\$1 = C. THB36). The rationale given by the advisor to EPPO during the Solicitation Conference that this was to reduce the administrative burden of calculating the indexation mechanism on a monthly basis is inadequate. Slide 29 of the IPP Bid Solicitation Conference suggests that bidders *"...can utilize financial instruments to hedge foreign exchange risk."* however the Solicitation Guidelines (Section 10.3) state that *"IPPs will not be allowed to recover currency swap costs as a separate pass-through."*

Direct foreign exchange indexation at the reduced proportion (50%) and based on the standard formula would seem to be an appropriate solution in this regard, with the exchange rate to be fixed on issuance of the RfP. This incurs no greater administrative burden than applying indexation for inflation or for any other aspect of the tariff calculation. We would expect that invoices, effectively, will be self-generating once inputs are entered, for example, in relation to generation, cost of fuel, exchange rate and inflation indexes,

20. Fuel Supply Risk (Section 10.4; Slide 30): The requirement that IPP bidders proposing coal projects accept greater fuel supply risk (presumably meaning price risk) than gas projects seems at odds with the MOE's fuel supply / energy mix diversification objective (see Item 3).

21. New Transmission Facilities: All bidders will need to agree estimated costs of new transmission facilities with EGAT, whether pre or post-bid. Slide 17 states that these estimated costs "...will be considered as part of the price evaluation."

The cost of new transmission facilities (including upgrades to substations, if required) are, in all circumstances, outside the control of bidders and it may be argued / perceived that this requirement allows EGAT the potential to distort the bid outcome.

While some protection may be afforded through the 'non-discriminatory benefit' language at Section 5, it might be expected that this could be difficult to police in practice.

One suggestion, in this regard, would be to impose a fixed cost for new transmission facilities for the purposes of bid evaluation (e.g. based on a fixed cost plus a cost per km for transmission connection). This will remove any potential influence, perceived or otherwise, that EGAT may have on the bid outcome. The actual cost of the new transmission facility may then be agreed among the bidder, EGAT and MOE following project award.

22. EGAT Privatisation (Slide 27): Slide 27 refers to "Government Credit Support for EGAT". The provisions at §12.1.1.(c) (Default and Termination) and §27 (Privatization of EGAT) of the standard PPA would seem to adequately address this issue.

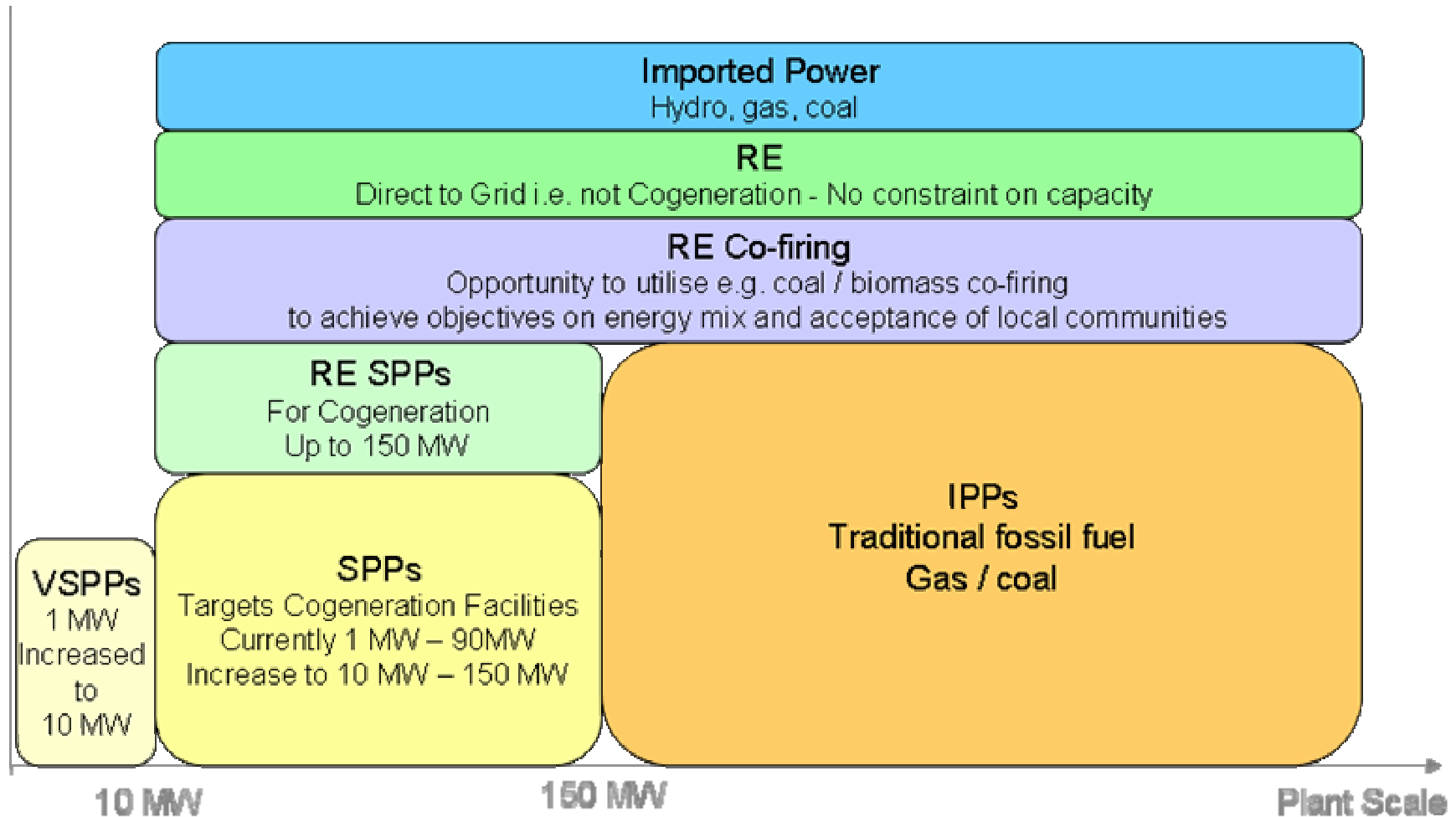
MOE may wish to consider the anomalous scenario under which one project is able to obtain approval from its lenders under §27 and another project fails to obtain that approval from a different group of lenders.

23. EIA (Section 4.8; Slide 35): The requirement for each IPP bidder to submit an EIA is relatively onerous and increases significantly the cost of bid preparation. It also places pressure on the bid submission timeframe (March-October 2007). Note that the EIA process may only be commenced following site and technology selection (with firm technical specifications).

A further concern of potential bidders, particularly bidders contemplating a coal project, will be the risk (outside of the bidder's control) of failure to obtain EIA approval which according to the Solicitation Guidelines will result in MOE retaining 15% of that bidder's bid bond.

**APPENDIX A:
OPPORTUNITIES FOR PRIVATE POWER PRODUCERS IN
THAILAND**

Opportunities for Private Power Producers in Thailand



APPENDIX B:
PROPOSED PRINCIPLES FOR RENEWABLE ENERGY POLICY

THAILAND RENEWABLE ENERGY POLICY

4 DECEMBER 2006

Thailand wishes to diversify its energy mix and to promote the use of Renewable Energy within its energy mix.

The use of Renewable Energy within Thailand's energy mix has the added benefits of reducing the environmental impact of using conventional fossil fuels and simultaneously displacing Thailand's need to spend foreign exchange on the import of fossil fuels.

It is anticipated that the majority of Renewable Energy in Thailand will be generated by biomass-fuelled projects (presently estimated to account for 90-95% of Renewable Energy capacity in Thailand). This will significantly benefit the agricultural community in Thailand.

The Ministry of Energy ("MoE") has a stated policy objective that 8% of Thailand's overall installed generating capacity by 2011 be contributed by Renewable Energy projects. It is estimated that this will represent approximately 2,300-2,400 MW¹⁶ of installed capacity by 2011.

Thailand's present Renewable Energy capacity is approximately 1,240 MW; of which only approximately 640 MW is delivered to the Thai electricity grid¹⁷.

The Energy Policy Planning Office ("EPPO") reports that the MoE's objective is to increase the installed generating capacity of Renewable Energy by 2,000 MW by 2011.

Against this background, it is important that Thailand establishes a Renewable Energy policy, tariff structure and contractual framework (i.e., Power Purchase Agreement ("PPA")) that will support investment in Renewable Energy projects and maximize the energy delivered, accepted and purchased from these investments.

It is in this context that we have prepared a set of principles for the development of a Renewable Energy policy ("RE Principles") for consideration by the MoE. These principles are set out as Part A hereto.

Part B sets out a conceptual mechanism for a Feed-in Tariff that may be used to support the cost differential between the expected cost of Renewable Energy tariffs and those achievable using conventional fossil fuels.

Part C sets out recommendations for a Renewable Energy PPA ("RE PPA"). We would welcome an opportunity to provide additional assistance to the MoE in making more detailed recommendations for an appropriate PPA, including the provision of a draft PPA that would support investment in this sector.

It is the industry's and investor's considered view that the adoption of the RE Principles set out in Part A, in conjunction with an appropriate tariff structure and RE PPA, will assist Thailand in meeting its objectives with respect to the role of Renewable Energy within Thailand's energy mix and place Thailand as a regional leader in this increasingly important sector.

¹⁶ Based on Thailand Load Forecast dated 27 July 2006 by Thailand Load Forecast Subcommittee. Source: EPPO.

¹⁷ Based on estimates available at EPPO's website www.eppo.go.th dated March 2006.

PART A: RENEWABLE ENERGY POLICY PRINCIPLES

1. Apply the Renewable Energy policy to projects that qualify as 100% Renewable Energy projects.

This is consistent with the Renewable Portfolio Standard introduced by the National Energy Policy Council (“NEPC” in August 2004); that is to say, that such projects shall be permitted to utilise fossil fuels only for the purposes of start up operations (i.e. 5 days equivalent full load operation).

Consideration may also be given to developing a separate policy regime to promote co-firing with renewable energy and fossil fuels.

2. Provide a ‘level playing field’ by establishing a Renewable Energy policy to apply to all Renewable Energy projects, including existing operating projects.

Provision should be made for existing Renewable Energy projects to elect to come under the Renewable Energy policy, including the application of the tariff mechanism (Principles 5, 6 and 7) and Renewable Energy PPA (“RE PPA”) (Principle 9).

3. Optimise delivery of Renewable Energy in Thailand’s energy mix by deeming Renewable Energy projects as ‘must run / must take’ facilities.

This is necessary to optimise the delivery of Renewable Energy in Thailand’s energy mix. It is inappropriate that dispatch of Renewable Energy projects, and therefore the fulfillment of policy objectives, be left in the hands of the power purchaser(s) – this should be controlled by the Government, and supported by the Feed-in Tariff mechanism (Principle 8), in order to meet Government policy objectives.

4. Provide for a guaranteed minimum dispatch for projects (e.g. biomass projects) that can accommodate a reasonably reliable / predictable availability and require dispatch assurances to optimise cost effectiveness and fuel supply planning and contracting.

Notwithstanding the ‘must run / must take’ requirement (Principle 3), a guaranteed minimum dispatch is essential to enable the generator to plan and contract fuel supply (including on a take-or-pay basis) which will generally be done with farmers / agricultural communities. This is also beneficial to the power purchaser to enable predictable and reliable dispatch, system planning and load flows on a more consistent and dependable basis.

5. Provide for an exclusive zone around projects such that no competing project utilising the same fuel type will be licenced within the exclusive zone.

This is essential to protect the fuel supply of the project and assure that the fuel supply will not be diverted to a subsequently established competing project – as has occurred in a number of instances in Thailand.

6. Create an appropriate tariff mechanism to match the capital cost and operating cost of Renewable Energy projects, recognising the typically higher initial capital cost for Renewable Energy projects.

The Capacity and Energy Payment components of the tariff will need to reflect the Renewable Energy technology employed in the relevant project.

7. Include in the Energy Payment component of the tariff the cost of fuel, on a pass through basis, based on either (a) a market price mechanism or (b) a fixed price with indexation to a Consumer Price Index (“CPI”) to account for inflation.

8. Provide for a 'Feed-in Tariff' to meet the differential between the Small Power Producer ("SPP") PPA tariff and the RE PPA tariff.

This will have the effect of making the power purchaser indifferent to dispatch between a Renewable Energy project and an SPP project. This is appropriate and consistent with the 'must run / must take' principle (Principle 3)

Proposals for Feed-in Tariff mechanisms are included at Part B hereof.

9. Introduce a Renewable Energy PPA that provides for an appropriate balanced risk allocation between the generator and the power purchaser.

The present SPP PPA (a) had its genesis as a basis for cogeneration facilities to sell excess capacity and energy to the Thai electricity grid and (b) was developed for the benefit of the power purchaser. It is heavily one-sided in favour of the power purchaser.

When applied to Renewable Energy projects such a contract serves to discourage investment whereas the objective should be to encourage investment in this sector.

In order to achieve a balanced risk allocation it is inappropriate that the RE PPA be written by the power purchaser without the involvement of the generator. In this regard we attach as Part C suggested principles to be included in an RE PPA.

10. Remove capacity constraints for Renewable Energy projects.

In looking to maximize the contribution of Renewable Energy, scale should be encouraged not confined.

Part B: Feed-in Tariff Mechanism

The Feed-in Tariff mechanisms contemplated below are based on 2006 estimated load factors and calculate the Feed-in Tariff that would be required if 6% or 8% of delivered energy was derived from RE projects.

The reality is that in 2006 Thailand has only approximately 640 MW of RE capacity which results in only an estimated 4,500 GWhr¹⁸ or 3.2% of delivered energy to the Thai electricity grid.

On this basis the MoE could employ a step-up approach to the imposition of the surcharge on delivered energy, whether applied to all delivered energy or only on non-RE energy delivered. For example, this approach applied in 2006 would have required a surcharge of approximately 1.8 satang / kWh on non-RE delivered energy under Alternative B below in order to provide an average Feed-in Tariff of approximately 50 Satang / kWh for RE projects.

Alternative A: Surcharge on delivered energy to support RE policy objective

2006 Estimated delivered energy =	140,287 GWhr ¹⁹	
Surcharge on delivered energy =	THB 0.05 / kWhr	
Contribution to Feed-in Tariff Fund =	THB 7.0 billion	
Proportion of delivered energy from RE projects =	8%	6%
Total contribution of RE projects =	11,223 GWhr	8,417 GWhr
Average Feed-in Tariff available =	THB 0.625 / kWhr	THB 0.83 / kWhr

Alternative B: Surcharge on non-RE energy to support RE policy objective charged to Non-RE energy generators

2006 Estimated delivered energy =	140,287 GWhr ¹⁹	
Proportion of delivered energy from RE projects =	8%	6%
Total contribution of RE projects =	11,223 GWhr	8,417 GWhr
Total Contribution from Non-RE Energy =	129,064 GWhr	131,870 GWhr
Surcharge on Non-RE delivered energy (charged to generator) =	THB 0.055 / kWhr	THB 0.055 / kWhr
Contribution to Feed-in Tariff Fund =	THB7.09 billion	THB 7.25 billion
Average Feed-in Tariff available =	THB 0.632 / kWhr	THB 0.862 / kWhr

¹⁸ Assuming a load factor of 80%

¹⁹ Based on Thailand Load Forecast dated 27 July 2006 by Thailand Load Forecast Subcommittee. Source: EPPO.

PART C: RECOMMENDATIONS FOR A RENEWABLE ENERGY POWER PURCHASE AGREEMENT

Following a review of the Independent Power Producer (“IPP”) PPA and the SPP PPA the following recommendations are submitted to the MoE for its consideration in the development of a Renewable Energy PPA (“RE PPA”).

In submitting our recommendations for an RE PPA, we have considered the importance of ensuring a balanced risk allocation which will promote investment in the Renewable Energy Sector in Thailand.

The recommendations assume the use of the SPP PPA as the starting basis for the development of the RE PPA. The recommendations set out below are proposed as modifications to the existing SPP PPA.

It is noted that the existing SPP PPA had its genesis in providing cogeneration facilities the opportunity to sell electrical capacity and energy to the Thai electricity grid (usually by sale to EGAT, as power purchaser).

Therefore, in certain respects, the SPP PPA provides a poor benchmark for a PPA to be applied to a Renewable Energy project that may sell electrical capacity and energy exclusively to the Thai electricity grid (i.e. through a power purchaser) and thus have as its principal, and likely only, source of revenue the revenue to be paid by the power purchaser.

In this context, despite the use of the SPP PPA as the base document, there are many areas where the IPP PPA could provide more appropriate guidance for development of an RE PPA.

1. **Milestone Obligation:** The generator is to achieve commercial operation by a date certain (“Commercial Operation Date” or “COD”) agreed between the parties.
2. **Testing and Commissioning:** Provision should be made for the power purchaser’s participation in the testing procedure. The contractual philosophy should focus on attempting to achieve the initially targeted capacity.

Provision should also be made for retest in the event of a shortfall with appropriate time periods permitted to prepare and schedule for the retest.

In the event that the power purchaser is not available, or does not make a grid connection available, to complete testing and commissioning of the power plant, the power plant should be deemed commissioned.

3. **Validation of Capacity:** The generator or power purchaser may request retest with appropriate notice period (30 days) up to an agreed maximum retests in any year (4 times) to validate the Contracted Capacity or, if applicable, declared capacity.
4. **Power Purchase:** Consistent with RE Policy Principle 3, the power purchaser would be obliged to purchase all available energy delivered by a Renewable Energy Project.

To support those projects able to meet guaranteed dispatch obligations in contracting fuel supply, a guaranteed minimum dispatch of 80% should be contracted; provided always that the power purchaser remains obliged to purchase all available energy.

5. **Capacity Payment:** The Capacity Payment should reflect the actual all-in investment cost and fixed operation and maintenance (“O&M”) costs of the Renewable Energy project based on the relevant technology.

Under no circumstances should the Capacity Payment be linked to the cost of developing and constructing a fossil-fuelled power plant that has no relevance or bearing on the cost of developing and constructing a Renewable Energy Project.

The Capacity Payment should be apportioned between foreign and local currency in proportions that reflect the actual investment cost and capital structure of the project, and should commence at COD.

A reasonable minimum guaranteed dispatch level should be agreed as the basis for setting the Capacity Payment. 80% dispatch (7,008 hours) over the course of a year is considered to be a reasonable guaranteed dispatch level.

Consistent with the amendments made to the SPP PPA, there should be no time-of-day provisions. These are superfluous in light of a must-run mandate.

6. **Energy Payment:** The Energy Payment should reflect the actual fuel cost and variable operating cost of the project.

The take-or-pay fuel payment associated with the minimum guaranteed dispatch is an important security arrangement for the planning and contracting of fuel supply.

The minimum guaranteed dispatch and associated Energy Payments must commence from COD (whether actual or deemed) and apply on a pro-rated basis for the first and last year of operation.

The generator should be paid the Energy Payment for energy delivered during testing and commissioning procedures.

7. **Fuel Charge:** The fuel charge component of the Energy Payment should be linked to its actual cost, and not to the cost of an unrelated fossil fuel.

The generator should be granted the option to elect either (a) a fixed and indexed fuel charge or (b) a market based fuel price mechanism (where a spot market exists for the fuel commodity). Where the generator requires specific terms consequent to its contractual arrangements for fuel supply, the power purchaser may review the terms of the fuel supply agreement.

If in a given year the power purchaser fails to dispatch the project at its minimum guaranteed dispatch level, a true-up mechanism may be required by which the power purchaser may take energy that it has paid for but not taken in a given year for an agreed number of subsequent years (e.g. 3 years;) over and above the minimum guaranteed dispatch (i.e., after meeting the guaranteed dispatch for the year in which the make up energy is being taken).

8. **Indexation:** The generator should be permitted to propose indexation for the following cost components:

Capacity Payment: To US\$ for a portion (up to a maximum of 80%) of the Capacity Charge relating to the investment cost recovery component.

Fixed O&M Costs: To US\$ for a portion of the Fixed O&M costs and to the relevant THB and US\$ inflation rates in the relevant proportion.

Variable O&M Costs: To the THB inflation rate.

9. **Operation and Maintenance:** The realities of operating Renewable Energy projects should be accommodated within the RE PPA, in terms of maintenance cycles and related maintenance outages.

10. **Force Majeure:** A distinction should be made between Force Majeure events and State Agency Force Majeure events.

In the event of Force Majeure the party suffering the Force Majeure event shall be excused from its obligations and permitted a day-for-day extension of time for the period of the Force Majeure

In the event of a State Agency Force Majeure event, the capacity and take-or-pay fuel payments should continue.

11. **Default and Termination:** Balanced default provisions need to be included in the RE PPA, including in respect of the power purchaser's performance and payment obligations (largely absent under the existing SPP PPA).

Reasonable cure periods should be included within the RE PPA to enable both the generator and the power purchaser to cure any default situation.

12. **Lender Step-in Rights:** Lender step-in rights should be accommodated, including appropriate cure periods following step-in by lenders to enable lenders to cure default, and provisions to allow lenders to transfer ownership and operations to a qualified replacement entity in the event of a generator default.

13. **Penalties and Liquidated Damages:** Reasonable penalties / liquidated damages ("LDs") are appropriate but the levels presently included in the SPP PPA and the events which result in penalties / LDs are too broad. LDs need to reflect the costs/damages actually suffered by the power purchaser should key events (delay in completion, capacity shortfall) not be met. Lenders, investors and the EPC contractor will all need to be able to reasonably define and justify the level and reason for LDs in order to accept these.

A threshold of 5% below contracted capacity before the imposition of LDs is reasonable.

In the event that capacity falls below the Contracted Capacity during the operating period (i.e. post COD) the generator should be penalised only for the shortfall in capacity for the period that the shortfall has prevailed – it should not be penalised on a punitive and retroactive basis as is presently the case under the SPP PPA.

Moreover, as noted above, the generator should be given the opportunity to retest and demonstrate capacity at or close to Contracted Capacity.

It is inappropriate to precipitate a default or termination for a project in respect of which the only cash flow may be from the sale of capacity and energy to the power purchaser - for example, through the imposition of punitive and excessive penalties on the generator that go well beyond the damages that could reasonably be suffered by the power purchaser. The present SPP PPA provisions have this effect.

14. **Development and Performance Securities:** It is appropriate for RE projects to lodge Development and Performance Securities. However, these should be set at reasonable and realistic levels that do not impair the project's ability to raise finance.

The present SPP PPA requirement for a Performance Security equivalent to a Net Present Value ("NPV") of 5% of projected total contract revenue will result in

a requirement for a Performance Security in an amount equivalent to approximately 20% of the total project cost.

The comparable IPP requirement is approximately 1.5% - a much more reasonable and realistic level.

15. Dispute Resolution: Disputes should, in the first instance, be resolved by good faith discussion of the parties, utilising, where applicable, an expert.

In the event that such good faith discussions are unable to resolve the dispute, referral to arbitration would be an appropriate dispute resolution mechanism utilising the rules of the International Chamber of Commerce (“ICC”) or similar internationally recognised format, with one arbiter appointed by each side and the third appointed by the other two arbiters.

The decision of the arbitration shall be binding on the parties.

The dispute resolution and arbitration procedures should accommodate the requirements of foreign investors by provision for English translation.