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October 12, 2005

Mr. Christopher E. Greacen, Ph.D.
Director, Palang Thai
315/247 Sathupradit 19
Bangkok, Thailand 10120

Dear Mr. Greacen,

Subject: Lao PDR: Nam Theun 2 Hydroelectric Project

This is further to our interim response of July 21, 2005 to your letter of June 27, 2005.

We appreciate your analysis and the interesting issues you have raised in your letter. We have thoroughly reviewed the issues you raised and the analysis you presented. A summary of our review is attached as an Annex to this letter.

In general, our response parallels the outline of your letter. However, many of the issues that you raised have been addressed in earlier correspondence. In these cases, we have briefly summarized our response, citing a link to previous correspondence on the Bank's NT2 project website.

We hope this response addresses the major issues you have raised.

Sincerely yours,

Ian C. Porter
Country Director, Lao PDR
East Asia and Pacific Region

Annex

Technical Response Note on NT2 Economic Analyses

A. O&M Cost Assumptions

We have reviewed the analysis of operations and maintenance (O&M) costs you have carried out. These data are drawn largely from the US and show a fairly narrow range of O&M costs – between 0.27 US cents/kWh and 0.41 cents/kWh. This range is far narrower than the range of O&M costs identified in the Bank's own investigations. Our analysis, drawn largely from international data, project feasibility studies, and internal Bank studies and reports, demonstrates that O&M costs vary markedly between projects, as summarized in the table in Attachment 1. This table shows a range of total O&M costs from 0.32 US cents/kWh to 0.69 cents/kWh, based on plants in diverse locations in Europe, Asia, the Middle East, Africa and North America. (The table expresses all data, including the data you have provided, in the common numeraire of US cents/kWh, assuming an illustrative 80 percent plant factor for the fixed O&M component.)

You will note that the figure adopted for the RELC analysis – 0.76 US cents/kWh[1] – is slightly above this range and considerably above the value used in RELC/2004. The Bank selected this higher value based on engineering advice that we had seriously underestimated this cost in the earlier report, and that technical and environmental performance characteristics of *future* privately-financed plants will result in much higher O&M than in the past.[2]

We also wish to note that a one-tenth of a cent (i.e., one mill) reduction in the O&M cost for CCGTs would reduce the project net benefit by about US$27 million. When compared with a Base Case project NPV of US$266 million,[3] the economic merit of NT2 would remain positive over a wide range of O&M assumptions.

B. Transmission Cost Assumptions

We are happy to clarify how transmission charges were applied for the study. The Bank and EGAT thoroughly discussed the cost basis for the required link between the Thai border and the 500 kV grid (at Roi Et), making certain that the capital cost assigned to NT2 for this required link neither exceeds nor understates the value of the works required to evacuate NT2 power to Thailand. This cost was estimated as US$135 million (US$82 million in present value terms), and that amount was added to the capital cost of NT2 for the least cost economic analysis. (The

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[1] This value is net of the 0.2 US cents/kWh assessed for CCGT-associated transmission, as discussed separately in Section B.

[2] This trend was also noted in a recent article entitled "Service to the (GT) Fleet" in the August 2005 issue of *Power Engineering*.

[3] The Bank's Project Appraisal Document (PAD) reports the Base Case NPV at US$266 million as well as results of several sensitivity analyses. The RELC report reviewed several scenarios, including one using the cost-risk framework on an incomplete data set which reports NPV at US$188 million, but the decision document on project appraisal is the Bank's PAD (see website link reference WL5) as explained in Section F of this letter. (Note: web link references are listed at the end of this document.)

cost of the line from the project site to the Thai border was already included in the NT2 project capital cost.) For purposes of the commercial analysis, EGAT's own estimate of the average commercial cost of import-associated transmission development in the Northeast (US$ 0.00615/kWh) was added to the NT2 tariff to value each kWh purchased from the project.

All CCGT energy (in both the economic and commercial analyses) was assessed a transmission charge of US$0.002/kWh[4]. This value is a generic estimate based on international experience with the all-in costs of building and operating high voltage transmission lines and substations; it provides for both the capital and operating cost of transmission works to the level of the first substation for generation-associated transmission and associated transmission reinforcement down to that level. The Bank did not consider it necessary to conduct a specific study for estimating this variable since a small variation in its value would not have a material impact on the overall conclusions of the analysis. In any event, for reasons explained immediately below, the Bank's assumption is most likely a low one.

The Northeast of Thailand is relatively under-provided with primary energy resources and depends considerably on energy flows from other regions to meet its electricity requirements. Once NT2 is commissioned, its production will be to a considerable extent absorbed in Northeastern Thailand. In a production/transmission structure without NT2, those loads, and in any event other load growth in Northeastern Thailand, would need to be served by relatively long transmission lines bringing thermal energy into the Northeast, as there is no natural gas transmission network that would allow the construction of CCGT capacity close to those load centers. The economic cost of transmitting NT2 firm energy from the Thai:Lao border to Roi Et is about 4.2 mills per kWh, based on the investment cost of US$135 million plus associated O&M, or more than twice our assumption of US$0.0020/kWh for associated CCGT transmission. However, we have used a conservative estimate of 2 mills per kWh for the average incremental CCGT transmission charge on the assumption that some future CCGT plants may be built closer to load centers.

C. Valuation of THB Power

In the system planning for hydro development in Lao PDR, it has long been accepted that the development of NT2 would reduce the energy output of the Theun Hinboun (THB) plant by 275 GWh per year.[5] Indeed, that reduction was assumed in the economic appraisal of the THB plant. For the NT2 assessment, however, the Bank took the conservative view that this reduction of energy supply from THB is real, and, therefore, should be considered as a cost to the NT2 project.

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[4] By comparison, European Transmission System Operators (ETSO) charges are in the range of US$0.0030/kWh to US$0.0100/kWh with an average of around US$0.005/MWh (US cents 0.5/kWh), which is much higher than what has been assumed in the RELC. Source: ETSO Tariffs Taskforce, Comparison on Transmission Pricing in Europe: Synthesis 2004, April 2005).

[5] See April 8, 2005 and March 30, 2005 letters from Mr. Ian Porter to Messrs. Greacen *et al* found at website links referenced as WL2 and WL3.

In determining how to value this loss, the important question to ask is how the existing demand now served by THB will be met.[6] The answer is that it will be met by increased thermal energy production from plants already operating on the Thai grid. These plants collectively will require more fuel and variable O&M in order to meet the shortfall. At the same time, THB will produce the same maximum power level at the time of Thailand's peak demand, so the energy reduction will not increase the need for generating plants. As a practical matter, it should be noted that the least-cost analysis does not "assign" a value to the reduction of THB energy; rather the system optimization model simply replaces this energy through increased production from the next lowest cost source, which happens to be existing CCGT capacity.

D. Renewable Energy, Demand Side Management (DSM)/Conservation, and Cogeneration Assumptions

As previously explained,[7] for the renewable energy (RE) component, only firm capacity that is economically superior to NT2 needs to be taken into account for the purpose of the economic analysis. Table 39 of the Danish Energy Management (DEM) report[8] identifies 300 MW of firm RE potential that is economic, of which 274 MW is considered in that report as practically feasible. In the 2003 Power Development Plan (PDP), EGAT had programmed 223 MW of such capacity up to 2006.[9] This is retained in our analysis. The residual 51 MW (274 MW potential minus the 223 MW included) that is not retained in our analysis is less than 1 percent of the total incremental capacity Thailand is expected to commission between 2004 and 2011. EGAT's obligation is to provide 5 percent of incremental capacity from renewable sources over the next six years. This will result in approximately the range of renewables development discussed here. Hence there is no significant difference between the NT2 project analysis, the DEM Report and EGAT's development obligations in respect of this capacity.

As previously explained,[10] the Bank carefully reviewed the DEM report on demand side management and conservation, and compared the data on economic potential presented in that report with past performance in order to assess what is likely to be achieved over the next several years. Successful development of a DSM program requires more than potential; it requires concrete programming, budgeting, financing, etc., which are not in place at this time. The Bank concluded that the amount of DSM included in the 2003 national demand forecast (920 MW by 2011) is a reasonable estimate of what is likely to be achieved.[11]

We hasten to add that this does not mean that the Bank does not support and encourage such developments but simply that a higher level of DSM can not be considered as a simple option to be selected or de-selected at will. It is unlikely that a power utility would stake its power balance

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[6] It is important to note here that this is purely an issue of supply, and therefore it would be incorrect to value this energy as incremental electricity demand as you have suggested in your letter.

[7] See April 8, 2005 and March 30, 2005 letters from Mr. Ian Porter to Messrs. Greacen *et al* found at website links referenced as WL2 and WL3.

[8] Impact of Energy Conservation, DSM and Renewable Energy Generation on EGAT's Power Development Plan (PDP), Peter du Pont, Danish Energy Management, 24 March 2005.

[9] This is also stated in the DEM report page 54, bottom of the page.

[10] See April 8, 2005 and March 30, 2005 letters from Mr. Ian Porter and December 17, 2004 letter from Mr. Robert Mertz to Messrs. Greacen *et al* found at website links referenced as WL2, WL3 and WL4.

[11] Throughout this note the "2003 demand forecast" refers to the August 2002 forecast of the Thailand Load Forecast Subcommittee, and the "2004 demand forecast" refers to an update prepared in January 2004.

on hard-to-predict DSM decisions made by millions of consumers, and it is not practically feasible to fine-tune the commissioning date of a major generation project according to the uncertain flow of progress on DSM targets.

In addition to the Base Case assumptions described above, the project economic analysis has addressed this issue in two other ways. First, the study relies on the more conservative 2003 national demand forecast, which is 2,097 MW lower than the January 2004 forecast for the year 2010 (27,711 MW as compared with 29,808 MW in the more recent projections). As indicated in our letter of March 30, 2005, even if all of the prospective DSM/EE savings were to be realized in the planning period, it would delay the optimal NT2 commissioning date by less than a year. This, however, does not negate the project's long-term economic viability. Further, this issue is also addressed in our study through the risk analysis. The estimate recommended for DSM in the DEM report is far less than the 5,792 MW margin between the base case and low case demand forecasts for 2010 in the Bank's risk analysis.

With regard to cogeneration, as mentioned previously,[12] relative to Thailand's total potential, only a small amount is likely to be offered for sale to the power grid. That portion is reflected in our study through small power producer (SPP) plants fired by agricultural waste products. Most cogenerated power is designed to serve off-grid agro-industrial enterprises. These loads were not included the grid demand forecast, and thus should not be included in the grid supply program used to evaluate NT2.

E. Committed Plant and Retirement Assumptions

Each time that Thailand revises its national demand forecast, EGAT amends the supply forecast commensurate with its goal of maintaining a 15 percent reserve margin. (A fundamental premise of the Bank's analysis, supported by successive PDP documents, is that Thailand will reduce its reserve margin to this level by 2010.) This supply forecast includes retirements, repowerings, and new capacity (self-built, IPP, and SPP). Part way through the preparation of the NT2 economic analysis, Thailand published a new demand forecast which projected substantially more peak load than assumed in the 2003 demand forecast being used in the Bank's work. The Bank conservatively decided to remain with the 2003 forecast, despite the fact that a lower demand forecast is less supportive of the 2010 commissioning date for which NT2 had been contracted.[13] That decision then required a careful plant-by-plant review with EGAT in order to determine which plants must be included as firm supply, and which should be candidates. The criterion for including a plant as firm capacity is that, at the time of the modeling work, contracts are irrevocably committed and financed with penalties for unilateral cancellation. Everything else, including repowerings (i.e., plants scheduled for retirement that can be re-conditioned for extended service) are treated as candidates. The proposed 700 MW CCGT plants you cite as "omissions" in your letter (Songkla - 2007, North Bangkok - 2009, South Bangkok - 2009, and Bang Pakong - 2010) were *not* committed plants under this definition, and therefore were evaluated as generic CCGT candidates. These plants were not excluded from the analysis, but

[12] See December 17, 2004 letter from Mr. Robert Mertz to Messrs. Greacen *et al* found at website link referenced as WL4.

[13] As a practical matter, and given that our existing analysis was more conservative, it was not reasonable to ask EGAT system planners to re-specify all the input data for a completely new cost-risk analysis.

treated as candidates in the planning model.

That model determines which new supply candidates are economic, and schedules capacity based on least-cost criteria. The results for the base case demand forecast recommend four new CCGT plants for 2008 - 2010 (mirroring those which you cite as "committed plants"), along with the development of NT2 and subsequent new capacity (including repowering) that is economically justified, while maintaining the target reserve margin.[14]

F. Risk Analysis

We regret any confusion that may have arisen in reviewing the RELC cost-risk analysis. To restate for the sake of clarity, the study does evaluate high, base, and low case scenarios for NT2 construction costs, but only base and low case scenarios for the two other sensitivity variables, the demand forecast and natural gas prices. Low construction costs were applied only for cases for which an offsetting high construction cost was also evaluated. This was not the case for the demand forecast and gas price scenarios, for which no high cases were evaluated. In order to apply the complete cost-risk framework, base case values were substituted for the missing high demand forecast and gas price scenarios. This approach in effect biased results against NT2, since these two variables were evaluated as 75 percent probability of base case and 25 percent probability of low case results. This approach explains why the results presented in RELC are lower than those presented in the formal Project Appraisal Document (PAD).[15] The project has substantial risk margins built in at two levels (procurement and construction), with fixed price commitments and penalties, but we still assigned a 25 percent probability to a 30 percent cost-overrun.[16]

In this regard, it must be noted that the PAD, developed from the RELC supporting study, is the definitive document presented for the decision of the World Bank's Board on NT2. That document concludes that the Base Case economic benefit from NT2 is on the order of US$266 million. The Bank's statement of the Economic Cost-Risk analysis is presented in Annex 11, Section A.4, of the PAD; the scenarios calculated for this purpose are displayed in Table 5 on page A129 and explained in the text. Table 5 has scenarios with elements favorable and unfavorable to NT2 as explained. All cases for which there is at least one element of the key assumption set that could have a significant downside risk for NT2 are reported and the implications of the range of results are explained in paragraph 43 of Annex 11.

The Bank appreciates and shares your concern about the impact of electric power projects on the electricity prices that ratepayers will face. We acknowledge that if for whatever reason Thailand fails to bring its reserve margin to the target level over the time period programmed, the system would by definition be carrying unnecessary, excess capacity. This is a broad systemic risk that depends on overall demand and supply conditions and not on the NT2 project alone. NT2 will

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[14] See RELC, Table 18, p. 47. Of course, many of these candidates are not economic under a low demand scenario, and are therefore not selected by the model as capacity additions; see RELC Table 20, p. 50.

[15] World Bank Report No. 31764-LA, March 31, 2005. See website reference link WL5.

[16] Compared to average cost under-estimation of 27 percent reported in Bacon R.W. et al (1996) "Estimating Construction Costs and Schedules: Experience with Power Generation Projects in Developing Countries." World Bank Technical Paper No. 325.

contribute to meeting less than five percent of Thailand's incremental energy demand growth between 2004 and 2015 inclusive based on the 2003 demand forecast.

G. Bank Lending Policies

The Bank's financial support instruments do not subsidize power projects. The Bank's guarantees are developmental instruments designed to mitigate political risks not included in the commercial rate of return expected of similar projects developed in areas where covered risks are much lower. This is not a subsidy – it levels the playing field allowing certain countries to host projects that are expected to earn normal commercial rates of return. In the case of NT2, guarantees from the Bank and MIGA enabled the project to mobilize about US$1 billion in private sector funding which would have been otherwise unobtainable. The NT2 project is therefore not being subsidized by the World Bank. The same instruments could be made available to any private power project that is economically justified.

Conclusion

Finally, in light of the foregoing considerations, we are of the view that the analyses underlying the decision to support the NT2 project are robust and that no useful purpose would be served by redoing them. In such analyses, there are always areas in which choices of assumptions and approach can be made, depending on the judgment of the analysts, about what is most relevant and reasonable for the situation at hand. Over the extensive period of time used to complete this analysis, the Bank's analysts have considered, in great depth, all of the issues you have raised. With the benefit of hindsight, of course, one may always point to this or that assumption or approach that could have been handled differently. For example, as stated in the PAD, page A128, paragraph 38, the values we adopted for natural gas "may well understate eventual long-term natural gas economic values." In light of current developments in international and domestic hydrocarbon markets, a higher gas price forecast for the analysis might have been more appropriate. However, the fact that the NT2 project is a fixed price contract for up to twenty-five years, partly based on hydrocarbon values as perceived when the contracts were negotiated, means that Thai consumers will have available about 1000 MW of stable, predictable and reasonably-priced energy supply from NT2. This is in the interest of all concerned parties.

Website Link References

WL1/ http://siteresources.worldbank.org/INTLAOPRD/Resources/RELC2005v3.pdf

WL2/ http://siteresources.worldbank.org/INTLAOPRD/Resources/ResponseLetterApril82005.pdf

WL3/ http://siteresources.worldbank.org/INTLAOPRD/Resources/Greacen.pdf

WL4/ http://siteresources.worldbank.org/INTLAOPRD/Resources/293582-1092106399982/492430-1092106479653/palang_thai_three_economists_response_from_robert_dec17-2004.pdf

WL5/ http://www-wds.worldbank.org/servlet/WDSContentServer/WDSP/IB/2005/04/08/000012009_20050408085158/Rendered/PDF/317640corr.pdf

Attachment 1: Comparative O&M Costs

World Bank Data

Source	FOM in UScents/kWh	VOM in UScents/kWh	Total O&M in UScents/kWh	Notes
USA 1	0.3567	0.2000	0.5567	1/
USA 2	0.1475	0.2070	0.3545	2/
India 1 ("Claimed")	0.0824	0.3294	0.4118	3/
India 2 ("Allowed")	0.0659	0.2634	0.3293	3/
Japan	0.1000	0.4000	0.5000	4/
USA (Cal 1)	0.2568	0.2500	0.5068	5/
USA (Cal 2)	0.2581	0.2280	0.4861	6/
China	0.1665	0.2561	0.4226	7/
Yemen 1 (low of 5, based on VOM)	0.0870	0.5430	0.6300	8/
Yemen 1 (high of 5, based on VOM)	0.0832	0.6060	0.6892	8/
Yemen 2	0.2072	0.3890	0.5962	9/
Southeast Europe (low of range)	0.1952	0.1560	0.3512	10/
Southeast Europe (high of range)	0.4110	0.2640	0.6750	10/
CCPP	0.1427	0.1800	0.3227	11/
CCPP	0.2140	0.2600	0.4740	11/
OECD (low of range)			0.0702	12/
OECD (high of range)			0.6758	12/
Palang Thai Data				
Thailand (RELC-2005 Table 15)	0.2568	0.5000	0.7568	13/
Thailand (RELC-2004 Table 13)	0.2397	0.0564	0.2961	
Thailand (EGAT)	0.2277	0.0536	0.2813	
USA (Cal) (CPUC MPR)	0.1514	0.2550	0.4064	
USA (Cal) (CPUC merchant CCGT)	0.1936	0.1360	0.3296	
USA (Cal) (CPUC utility-owned CCGT)	0.1936	0.1360	0.3296	
USA (Wash) (Puget Sound Energy)	0.1570	0.2000	0.3570	
Ireland (Comm. for Electricity Regulation)	0.1463	0.1260	0.2723	
Australia (NSW Regulatory Tribunal)	0.0371	0.3140	0.3511	

1/ 500 MW class, US plants. "O&M" includes items like plant staff, materials, insurance, auxiliary power, and ISO membership fees. Source: La Capra Associates, Boston, Massachusetts.

2/ Adv Gas/Oil Comb Cycle (CC). Assumes data is $2002/kW-year (although expressed only as $2002/kW"). No adjustment made for inflation from 2002 dollars. Source: EIA, Table 38.

3/ Data is for 2003-2004, from the Central Electricity Regulatory Commission - New Delhi, for "claimed" rate. Applying exchange rate of $1=R42. Assumes Total O&M = 80% variable + 20% fixed. Data reported as "Rupees in lakh" (at 4363 for "claimed" by the power producer and 3489 for "allowed" by the regulator). Conversion made on the basis of 1 million Rupees=10 lakh. "As calculated" data uses 80% load factor for comparability. Originally-reported data was based on a 69% load factor, resulting in Total O&M of 0.4774 US cents/kWh for "claimed" (with imputed FOM of 0.0955 US cents/kWh and VOM of 0.3819 US cents/kWh) and 0.3818 US cents/kWh for "allowed" (with imputed FOM of 0.0764 US cents/kWh and VOM of 0.3054 US cents/kWh).

4/ Toyo Engineering / Chubu Electric. Assumes 25-year plant life; 80% capacity factor; 10% discount rate; ad 2004 price for 300 MW oil/gas fired combined cycle. O&M numbers are per kWh, which are based on levelized generating cost calculations over an expected 25 year life and are based on their experience in Japan with some 25-30 CCGT units. The cited numbers are from a draft study that is not yet finalized.

5/ Underlying data is from several new CCGT plants in California. Values reflected are values recommended by the regulatory bodies: California Wind Energy Association / California Biomass Energy Alliance / California Cogeneration Council). Note: Among the plants considered, the highest values for FOM and VOM both occurred with one plant and the values were $36.0 $/kW-yr and $3.08 $/MWh, respectively. Reference document available at: http://calwea.org/Attached%20Documents/Recd%2004Mar05/CALWEA-CBEA-%20CCC%20comments%20on%20the%20MPR%20Staff%20Report%202-28-05.pdf

6/ The table presents data from 6 plants and the resulting averages for FOM and VOM. The numbers presented above are those averages. Data is from Table 2 of reference document available at: http://calwea.org/Attached%20Documents/Recd%2004Mar05/CALWEA-CBEA-%20CCC%20comments%20on%20the%20MPR%20Staff%20Report%202-28-05.pdf

7/ Data is from feasibility report for project in Guangdong province, China. Exchange rate is $1=RMB 8.26 Yuan (before) and about RMB 8.2 Yuan now. Capacity is 2x390 MW. Assumes data is Yuan per kW-year (although reported only as "Yuan/kW").

8/ Data is from a study conducted by PPA Associates (2002) and is drawn from 5 single cycle GT plants. Data is based on a GE turbine with ISO capacity rating of 122.5 MW and takes into account aging, altitude and ambient temperature.

9/ Data is from a draft World Bank report of September 20002. CCGT candidate assumes capacity of 362 MW plant at sea level. Variable O&M number cited is non-fuel.

10/ Data is from a Generation Investment Study in Southeast Europe. Variable O&M is taken from sources where some adjustments are made for local labor costs. VOM does not include fuel cost. Data is for a range of capacities from 150 MW to 500 MW. Assumes exchange rate of $1.2=1Euro. December 2004 final report.

11/ Colenco Power Engineering Ltd. Combined Cycle Power Plant 400 MW. O&M costs do not include any provisions for fuel, insurance coverage or for taxes. Estimated annual O&M costs based on 7000 OH/a. Used 80% plant load factor.

12/ Data is from OECD/ AEN-NEA / IEA study: *Projected Costs of Generating Electricity* (2005 Update), Table 3.5 (Projected 2010 costs for gas-fired power plants). Data is reported as specific annual O&M costs (per kWe) by selected countries on a levelized generation basis. The "lower end of range" data presented under "as calculated" is based on the reported data for Greece ("GRC-G2" data point) and the "higher end of range" data is for the Slovak Republic (data point "SVK-G").

13/ Although the RELC (March 2005, Table 15) reports VOM as .007 $/kWh (or 7 $/MWh), this figure <u>includes</u> transmission costs of .002 $/kWh (or 2 $/MWh). To be on a basis comparable to the other data presented in the table immediately above (which does <u>not</u> include transmission costs), the correct VOM figure to use is .005 $/kWh (or 5 $/MWh).