Lao PDR

Nam Theun 2 Hydroelectric Project

Project Economic Analysis

The World Bank

March 14, 2005

Project Economic Analysis

A.1 Scope of Analysis and Sources of Data

1. The economic analysis for the NT2 project addresses three fundamental questions:

- Does the Thai market, which will absorb about 95 percent of the power generated by NT2, need the power from this project?
- Is NT2 an economic, least-cost source of electricity supply to the Thai and Laotian power markets? How robust is the base-case answer to this question?
- What is the project ERR and how sensitive is it to alternative key assumptions?

2. The economic analysis covers the regional power market, defined as the power markets of Thailand and Lao PDR supplied by the project. NT2 is essentially an enclave project harnessing water in Lao PDR to provide about 95 percent and 5 percent of its electricity to the Thai and Laotian power markets, respectively. Without the project, Thailand adopts its next best alternative and Lao PDR imports additional electricity from Thailand, this being its most economic alternative, as discussed below.

3. The main data sources for the Thai power market are EGAT, MEA and PEA, who gave generously of their time and information to meet the Bank's due diligence requirements. Much of the least-cost system expansion analysis for Thailand was carried out in EGAT, based on terms of reference developed by the Bank and key input assumptions acceptable to the Bank. A series of interviews with the Department of Mineral Fuels, National Energy Policy Office (both of the Thai Government), PTT, UNOCAL, Amerada Hess, Chevron/Texaco and Total/Elf/Fina were very helpful for developing economic information on prospective demand and supply conditions and the value of natural gas in Thailand. This is important, because natural gas is the backbone fuel for the Thai power system and combined cycle gas turbine (CCGT) plant is the current and projected economic generation alternative to NT2. Information about NT2 project investment and operating costs, and the environmental and social (E&S) costs and benefits come from the lenders' financial model of December 2004. EDL, Meritec-Lahmeyer and the tariff study prepared for Lao PDR by Elektrowatt AG, Ekono Ltd. and Fichtner provided most of the information needed for evaluating the economic merit of NT2 in the Laotian (Central-2 grid) context.

A.2 The Thai and Laotian Power Markets

4. The economic analysis for the project seeks to determine whether or not the NT2 project is an economic, least-cost component of electricity supply to the Thai and Laotian power markets. This question is addressed with a comprehensive analysis of electricity demand and supply in Thailand, the main market for the project, and a brief analysis of the Laotian market. Furthermore, a probabilistic cost-risk analysis has been done for the Thai market to see whether a decision to proceed with NT2 for the intended commercial operations date (COD) of November 2009 is economically robust to a wide range of electricity demand growth rates, NT2 project costs and values of natural gas. These are the key uncertainties that could have a substantial impact on the value of a decision to build the project.

Historic Demand and Supply Conditions in Thailand

5. Demand and supply conditions in Thailand are of particular importance as the country now has surplus generating capacity, because of the economic downturn in the late 1990s and the large amount of capacity that was then under development and could not be stopped on reasonable terms. In 2004 peak load was 19325 MW. Adding a 15 percent margin relative to peak load for reserves (EGAT's generation reliability requirement), the installed capacity requirement was about 22,224 MW; however installed capacity was 25,705MW, resulting in an excess of 3480 MW, or 15.7 percent of peak load plus required reserve.[1] With economic recovery underway for the past several years, demand for electricity has resumed the growth that was interrupted in the late 1990s. The Thai power market is very large, hence low rates of change on a large base result in large absolute reductions of surplus capacity in the medium term and requirements for large amounts of new capacity over the longer term. This is the case even after including realistic estimates of savings achievable through demand management and energy efficiency programming.[2] Some large hydro projects can be economically challenging because of slow rates of capacity absorption in the receiving power system. While 920 MW net (the Thai share of NT2 capacity) sounds large, as shown in the analysis below, by COD it is likely this amount of capacity would be needed to meet the system reliability criterion and would be absorbed in less than one year of demand growth. Hence, in the case of NT2, the more important issues concern the appropriate timing of new power plants and comparative costs between NT2 and natural gas-based CCGT plants, given Thailand's access to large volumes of natural gas.

6. The analysis begins with a retrospective on the demand and supply situation, then looks at demand and supply projections and the timing of the NT2 investment, followed by an analysis of comparative project costs and the least-cost risk analysis.

7. Over the decade 1993 to 2003 inclusive, GDP grew at an average annual rate of 3.1 percent and electricity demand 6.5 percent. This relationship is shown in Graph 1, where the base of the GDP index is scaled to the level of base electricity consumption (1993) for ease of graphing and comparison between the two series.

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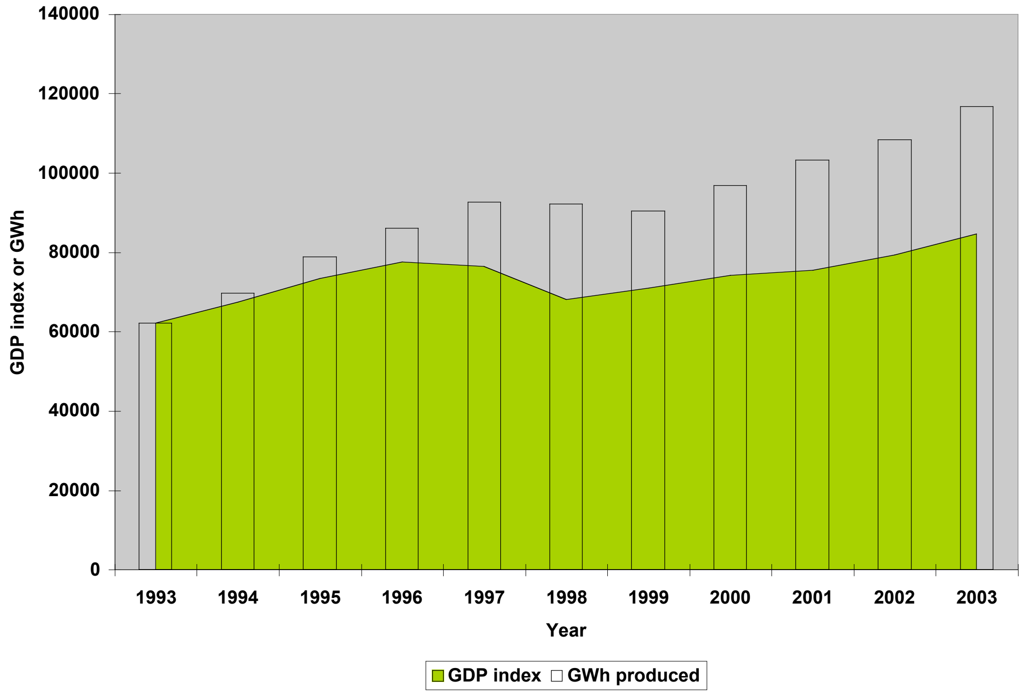
1 EGAT: "Thailand Power Development Plan", Bangkok, August 2004. The inference that capacity exceeds target reserves is ours, based on demand and supply data in the referenced document.

2 The Bank commissioned an independent assessment by Danish Energy Management A/S, Bangkok (draft dated December 21, 2004) of incremental energy conservation, demand management and renewable energy potential for Thailand.

Graph 1: Electricity Production and GDP Growth (Thailand, 1993-2003)



Source: GDP data: World Bank; Electricity Production, EGAT

8. Graph 1 indicates that trend changes of electricity demand lagged those of GDP and were much less severe:

- In 1997, at the peak of the Asian financial crisis, electricity demand grew while GDP shrank.
- In 1998 electricity demand dropped a little while the GDP decline was large.
- In 1999 GDP started to recover but electricity demand did not.
- From 2000, electricity demand growth substantially out-paced GDP growth. Over the four years from end 1999-2003 total GDP growth was 19.1 percent and electricity demand 29.1 percent.

9. This kind of relationship is not surprising, as the stock of electricity-using equipment does not shrink with a short (even severe) economic downturn, while consumers and businesses tend to expand their equipment stock as the economy recovers. On the whole, high growth of electricity demand cannot be attributed to subsidized pricing. On average, Thailand has commercial cost-recovery tariffs subject to regular periodic adjustment, as laid down in legislation. There are cross-subsidies between utilities and consumer categories.

10. There is a discrete change in the demand growth profile comparing the early 1990s to the early 2000s. Until 1996, electricity demand growth ranged between about 9 percent and 14 percent per year, compared with 5 percent to 7 percent since 2000. Recent GDP growth has also lagged the rates of the early 1990s. It was only by 2002 that GDP recovered to the 1996 level. In 2003, GDP grew by 6.7 percent (well above most forecasts for growth in the 5 percent range) and electrical energy consumption (GWh) grew by 7.7 percent (also well above the

forecast of 5.9 percent). In 2004, peak load was 19,325 MW versus forecast peak load of 19,029 MW. Hence the demand forecast has been considerably over-achieved in respect of energy consumption (GWh) and slightly over-achieved in respect of peak load (instantaneous MW of demand at peak). Thailand has low and stable system losses – about 7 percent from generation to end-user.

Electricity Demand and Supply Forecast in Thailand [3]

11. Thailand has a sophisticated, institutionalized electricity demand forecasting process. The national electricity demand forecast used in this study is that of August 2002. It projects energy production growing by 6.17 percent per year, on average, from 2003 to 2016. Thai GDP grew at 6.7 percent in 2003 and the Bank expects continued growth in the range of 5 percent to 6 percent per year from 2004 to 2008; hence, based on recent experience, the electricity demand forecast is well related to the range of expected GDP growth. With GDP growth in this range, the demand forecast may understate requirements; this probably explains why Thailand revised the demand forecast upward in January 2004. For purposes of project evaluation, however, the Bank has maintained the lower 2002 forecast. A lower rate of demand growth challenges the project's economic viability, thus providing a more severe "Base Case." It also reflects an implicit judgment that the 2002 demand forecast may embed less downside risk than that of 2004.

12. The demand forecast includes 928 MW of demand management programming that EGAT considers reasonable to achieve from 2006 to 2010. This means that the base case demand forecast has been reduced by 928 MW relative to what it would have been without this programming. In a separate study on demand side management (DSM) and renewable energy potential in Thailand commissioned by the Bank,[4] the author concluded on the basis of a careful review of existing studies that DSM and energy efficiency programming could be as much as 2207 MW at peak, or 1279 MW above the estimate now included in the base case demand forecast. Achieving DSM potential depends upon the efficacy of intentional programming and the response of millions of electricity consumers. The larger the estimated amount of DSM potential, the greater the uncertainty of achieving it. This consideration makes it reasonable to consider this incremental 1279 MW of demand management as part of the demand risk analysis. Seen in this context, the additional 1279 MW would change peak demand in 2010 from 27,263 MW to 25,984 MW, thereby reducing the base case demand growth rate between 2002 and 2010 from 6.6 percent per year to 6.0 percent per year; however, the low case demand growth rate adopted for sensitivity testing in the analysis for this PAD is 3.4 percent per year over the same period. Hence, this uncertainty about the extent of additional DSM is a small part of the already assumed demand uncertainty range for the risk analysis in this document. As well, the expected base case increase of peak load plus associated reserve would be 1913 MW between 2009 and 2010. Hence, if all of the additional 1279 MW DSM were achieved, this would still only delay the optimal timing of the NT2 project by less than one year.

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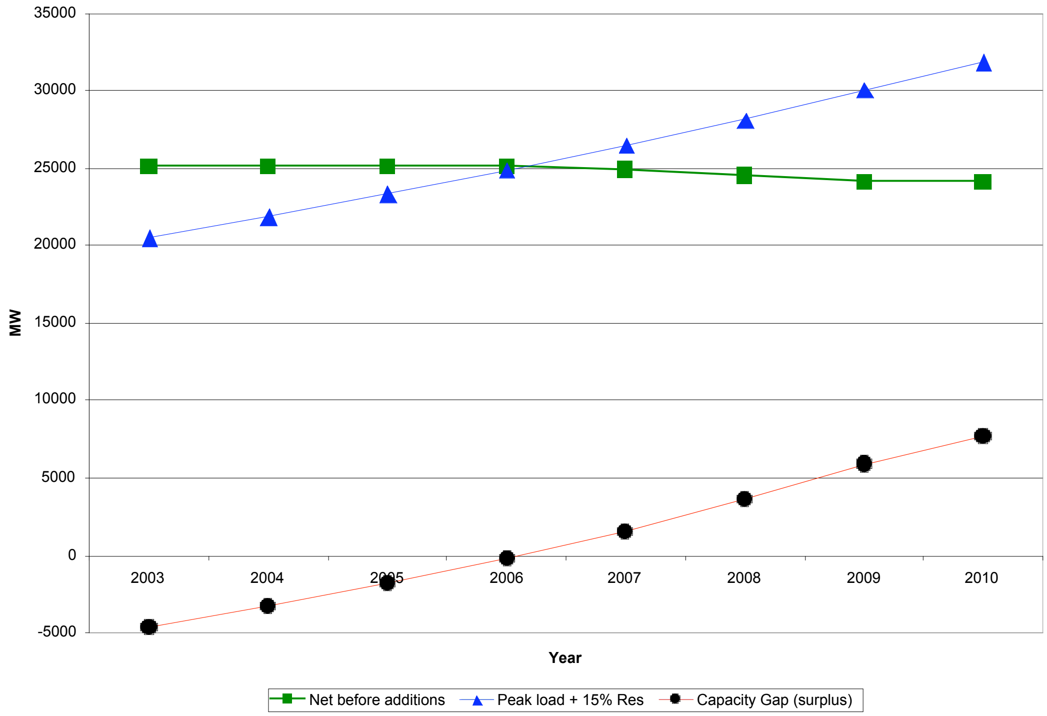
[3] For the demand and supply and least-cost analyses, readers are also referred to the Bank-commissioned Thai power market study: Vernstrom, R. "Nam Theun 2 Hydro Power Project - Regional Economic Least-Cost Analysis", Bangkok, March 2005.

[4] Peter DuPont, "Impact of Energy Conservation, DSM, and Renewable Energy Generation on EGAT's Power Development Plan (PDP), Danish Energy Management A/S, Bangkok, draft December 21, 2004.

13. On the basis of this demand forecast, excluding new plant from end-2003, the capacity surplus will be consumed by 2006 (see Graph 2).[5] By 2009, Thailand will need approximately 5,900 MW new capacity.[6]

Graph 2: Capacity Gap – Thailand (2003 – 2016)



14. To fill the expected capacity gap, apart from the net 920 MW from NT2, EGAT will need to buy new capacity or refurbish old capacity, bringing demand and supply into near-balance over 2008-2009. However, by 2010 a capacity deficit approximately the size of its NT2 share opens, growing to about three times that amount by 2011.[7] From the time NT2 is expected to be commissioned, it will displace the most expensive thermal energy on the system and cater for demand growth.

15. Peak load will grow at about the same rate as energy consumption, implying a stable system load factor of about 0.734. At this growth rate, the annual increase of energy requirements starts at 6,371 GWh in 2003, becomes 10,940 GWh in 2009 and 13,514 GWh in 2016.

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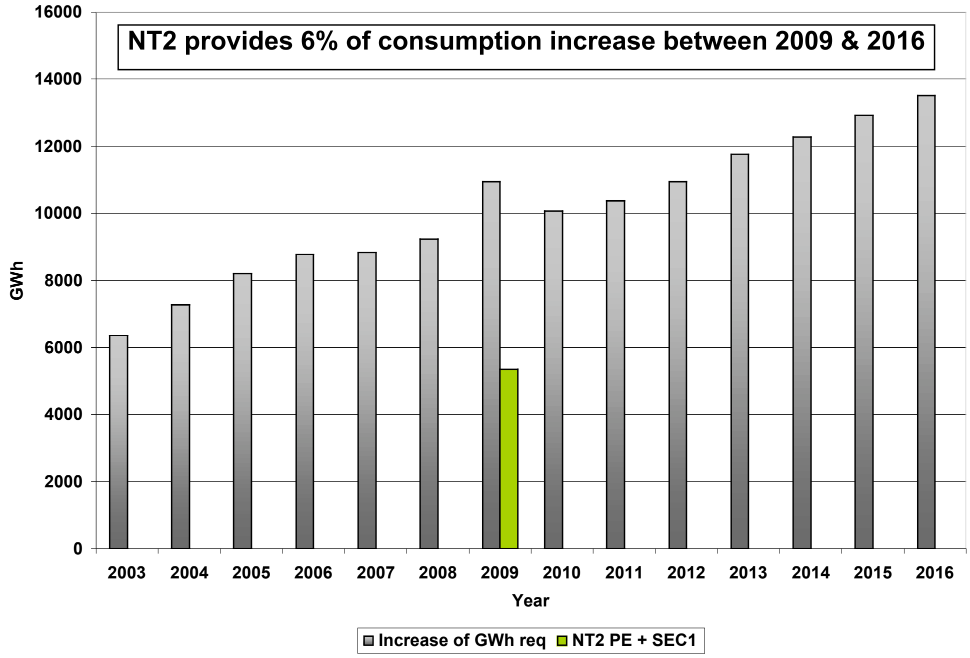
5 Absorption of excess capacity could be completed earlier if consumption continues to exceed the forecast.

6 The slight bump-up of incremental demand in 2009 relative to trend growth (Graph 2) happens because a large scale new steel mill (Sahaviriya Steel Group) is expected to commence operations that year.

7 Additional detail on the supply-demand balance appears in the "Regional Economic Least-Cost Analysis", March, 2005, Table A-6-1 in the Appendix at the end of the study.

16. By contrast, NT2 will supply Thailand with about 5,354 GWh when it comes on line in 2009. These relationships are shown in Graph 3 below, sourced from the Base Case demand forecast.

Graph 3: Increase of Annual Generation versus NT2 Supply – Thailand



This graph demonstrates that by the time of NT2 COD, the project will supply about one-half year of energy demand growth. NT2 would provide about 6 percent of the incremental energy requirement over 2009 to 2016.

A.3 Electricity Demand and Supply Forecast – Lao PDR

17. Lao PDR will be committed to buy up to 200 GWh of NT2 energy, but may buy up to 300 GWh per year. Lao PDR's electricity supply system is small and not integrated. There are four grids, none of which are interconnected. NT2 would serve the Central-2 grid (CR-2) around Thakek and Savannakhet, one of the two larger grids.

18. CR-2 demand is expected to grow rapidly, given the small size of present consumption, the large scope for electrification, the big market for irrigation pumping (to replace unreliable and expensive Diesel pumps), plus air-conditioning, some industry, and government administration. ADB, IDA and Japan are the main parties financing electrification. The Xe Pon gold and copper mine is in operation and will employ 1,600 people. It needs 305 GWh per year. In 2003, energy consumption at end-use was 140 GWh and is expected to be 320 GWh in 2010, excluding the mine, or 625 GWh, including the mine. The corresponding supply requirements, including losses but without the Xe Pon mine, are 168 GWh in 2003, growing to 386 GWh by 2010. With the mine included, the 2010 energy requirement is forecast to be 691 GWh. The anticipated supply program to meet this total energy requirement is expected to be:

Table 1: Lao PDR, CR-2 Electricity Region Supply Forecast

Source	Supply (GWh)
Theun Hinboun Power Co.	377
Vietnam	10
CR-1	34
Nam Theun 2	270
Total Supply	**691**

Thus, NT2's minimum take obligation is expected to be fully absorbed soon after COD, reaching the maximum allocation of 300 GWh.

A.4 Least Cost Analysis

Thailand

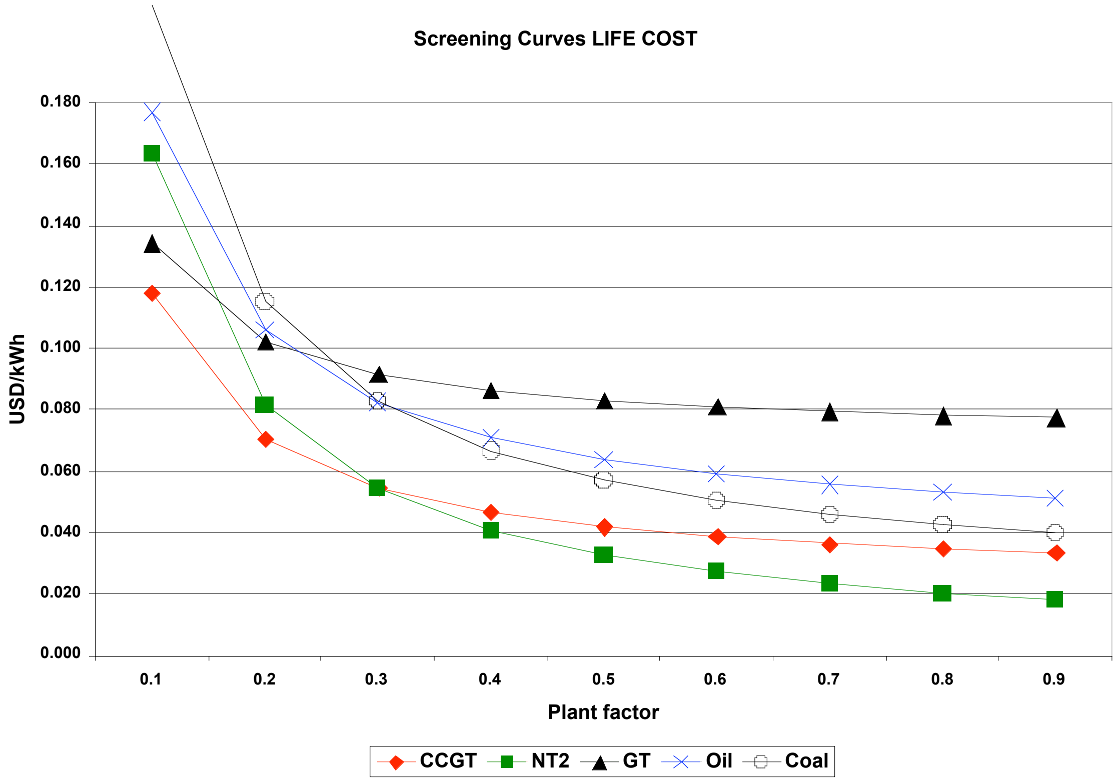
19. Thailand can generate electricity from a range of generation technologies and primary energy types: NT2, oil-fired steam, coal-fired steam, gas turbines (GTs) and CCGTs burning natural gas, and renewable energies such as biomass, wind, solar and mini hydro. According to EGAT, these renewable energy forms will play a positive but very small role in the total generation mix because of their high cost, and for some of them – limited availability. There are pilot projects using biomass - rice husks, sugar cane, etc. Based on discussion with EGAT the biomass potential that can be supported from the annual availability of raw material is about 700 MW. The biomass potential is small relative to annual load growth, and the generating cost is about THB 3/kWh (over US cents 7/kWh, based on an EGAT pilot project); this cost is close to the end-user tariff, hence uneconomic at the bulk power level. By 2004, Thailand will have the largest solar project in the region – a 500 kW solar cell, producing at THB 12/kWh (US cents 30/kWh). Thailand is a low velocity area for windmills, and cost is high: about THB 10/kWh. EGAT is looking for geothermal resources, but so far the potential seems very limited. EGAT expects renewable energy to grow from 37 MW in 2002 to 197 MW by 2006. Government policy requires that 5 percent of incremental supply within the current plan period be renewable energy.[8] Based on incremental capacity requirements to 2010 of about 5,900 MW, this would call for roughly 300 MW of such plants by 2010, consistent with the estimate for firm capacity from renewables as reported in the Danish Management Consulting study. The power system modeling for this appraisal includes the scheduled 197 MW. The additional 103 MW that may be developed by 2010 may be important for the country's renewable energy development, but would have no measurable impact on the results concerning NT2 reported here.

20. Using conventional screening curve methodology, Graph 4 shows comparative economic costs for the most prominent large-scale generation options available to Thailand. A screening curve shows the cost per kWh of a generation plant at a range of capacity utilization rates (or CU rates). Hence, in Graph 4, CU rates are along the horizontal axis ranging from 10 percent to 90 percent and cost per kWh is on the vertical axis ranging from 0 US cents to 18 US cents per kWh. Each technology has a curve, any point of which shows the cost per kWh at the

[8] The Danish Energy Management Study (footnote 7) indicates that the scope for firm capacity from renewable energy projects may be about 300 MW over the remainder of the decade.

corresponding CU rate. For example, at a 10 percent CU rate, the curve with diamond symbols (for CCGT plant) indicates that the cost per kWh would be about 12 US cents, but drops to about 7 US cents at 20 percent CU. This happens because the same fixed capacity and non-fuel cost covers twice the amount of energy production. Comparing screening curves between technologies shows which ones are least cost at any point in the CU range. NT2's average annual plant factor would be about 0.6, hence this is the appropriate plant factor at which to compare its costs with those of other plants at various plant factors.

Graph 4: Screening Curve Analysis – Thailand



21. ***NT2 as the Least-Cost Option***. Table 2 below shows the input data behind the screening curves in Graph 4. The main alternative to NT2 in Thailand is CCGT. As shown in the Inputs Summary table below, while CCGT has a lower investment cost per kW of capacity than does NT2, it has variable operating and fuels costs that NT2 does not have. The screening curves in Graph 4 essentially show that once the 30 percent level of capacity utilization is reached for both of these technologies, the higher operating cost of the CCGT plant outweighs its initial capital cost advantage relative to NT2. Thus, ***at CU rates above 30 percent, NT2 is the least-cost alternative for Thailand.***

Table 2: Least-Cost Analysis Power Plant Cost Assumptions

	A	B	C	D	E	F	G	H	I
11	**INPUTS SUMMARY - ECONOMIC**								
12		**Disc rate**	**Plant life**	**INV $/kW**	**FOM $/kW**	**VOM $/kWh**	**Fuel**	**$/mmbtu**	**btu/kWh**
13	CCGT	0.10	25	510.15	18	0.007	natgas	2.27	7000
14	NT2	0.10	50	939.63	17.6	0	-	-	-
15	GT	0.10	15	310.00	10.46	0.0042	DDO	6.30	10500
16	Oil	0.10	30	792.00	19.56	0.0026	HFO	3.70	8870
17	Coal	0.10	30	1100.00	24.49	0.00298	Coal	1.60	9560

22. The interesting observations about these curves are:

- Single-cycle gas turbine and oil based thermal-steam capacity are generally more expensive than the other options at most CU rates, while coal could come close to competing with CCGT plant at very high CU rates;[9]
- NT2 is least-cost upward of about 30 percent CU. NT2 will operate at about 60 percent CU; and
- Given the high system load factor, relatively little capacity operates below a 30 percent CU rate. This screening indicates that under usual operating conditions, NT2 should be the least-cost solution, followed by CCGT plant.

23. The costs underlying these screening curves are the same data used in the cost-risk analysis described below. The E&S costs for NT2 included in the above comparison are those that the project will pay, as identified in the sponsor's financial model. They are about US$9 million (present-value) higher than the estimated economic values of the E&S impacts.

24. NT2's E&S impacts include the economic costs of mitigation, and the estimated economic values of residual impacts for which mitigation is inadequate or not possible. A separate study was undertaken to measure these impacts.[10] The present value of E&S impacts that it was able to calculate is slightly below the present value of E&S-related costs that the NT2 project is scheduled to pay to parties in Lao PDR. For caution, the analyses presented in this PAD include for E&S costs the higher scheduled project payout estimates rather than the estimated economic values. As no such studies were undertaken for the non-NT2 electricity generation alternatives, no E&S costs are attributed to the non-NT2 technologies – such as gas, oil or coal-based generation. To that extent, this difference in treatment moderately biases the "least-cost" analysis against the NT2 project.

Lao PDR

25. Lao PDR has several power supply options for the CR-2 region: additional imports from Thailand, NT2 and the smaller (75 MW) Xe Pon hydropower project in the southern part of Savannakhet Province, and Diesel generators.

26. ***NT2 as the Least-Cost Option***. Based the Lao PSDP, NT2 is the least-cost option for serving the CR-2 load.[11] The Lao PSDP provides the following supporting evidence. There are only two feasible hydropower resources for meeting the power needs of CR-2: (i) NT-2 and (ii) Xe Pon (75MW), located at the extreme southern end of Savannakhet Province. Xe Pon has a relatively low ranking among domestic hydropower developments, and presumably would be developed at a much later date. CR-2 topography is not conducive to mini-hydro development.

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9 GT capacity in Thailand uses Diesel fuel, because the plants are remote from gas supply and operate very little. The coal result depends on a long-term projection of coal prices of about US$34/tonne, which may be low.

10 Benoit LaPlante, "Economic Analysis of the Environmental and Social Impacts of the Nam Theun 2 Hydroelectricity Power Project," February, 2005.

11 Meritec Limited in association with Lahmeyer GmbH: "Power System Development Plan For Lao PDR, Auckland, New Zealand, 2004"

The only other generation source would be local diesel generator sets whose generation costs would be in the range of US cents 12-20/kWh, depending on size and location.

27. ***Imports from Thailand***. The CR-2 could also receive additional power imports from Thailand. Currently there are three 22 kV interconnection points – at Pakxan, Thakek and Mukdhan. There are plans for strengthening the interconnections. The commercial cost of Thai-supplied electricity is about US cents 5.7/kWh.

28. By comparison, the utilization of NT2 energy in the CR-2 Grid would require construction of the following 115 kV lines from the Thakek substation:

Line	Length (km)	Cost (US$ million)
Thakek-Pakxan	185	18.65
Thakek-Pakbo	93	9.37
Total	278	28.02

29. An estimate of the cost that EDL would incur for utilization of 275 GWh from NT2 at its main substations is as follows:

Levelized Energy Purchase at Thakek	US cents 3.58/kWh
Levelized Transmission cost at 10 percent discount rate	US cents 1.10/kWh
Total	US cents 4.78/kWh

The costs of downstream distribution (common to all generation options) are not included.

A.4 Economic Cost-risk Analysis

30. Under the base case conditions discussed above regarding the cost of NT2, the cost of competing technologies and the demand forecast, extensive power system modeling analysis demonstrates that NT2 has a Net Present Value (NPV) of US$266 million relative to the most economic non-NT2 alternative (for the most part CCGT plants). The accounting of this NPV is carried for the period 2004 to 2034, when the PPA expires.[12] Of course, over this long period of time, there could be substantial departures from base case assumptions for the key factors influencing the NPV of NT2. Therefore, a probabilistic "Cost-Risk" analysis was implemented to test the implications of alternative assumptions for these key factors.

31. The purpose of this analysis is to test whether a decision to implement NT2 now for an expected COD of November 2009 (the "NT2 Option"), versus not implementing it, is robust to a range of alternative outcomes for the key factors that could change in the future and would affect the NPV of the NT2 option. The perspective is that once the PPA is signed, a series of commitments with onerous penalties for non-fulfillment makes it very difficult to alter the COD. The same applies to other plant that EGAT has defined as firmly committed. However, other planned additions are insufficiently committed and far enough into the future that there is time to both recognize the need for altering their CODs and feasibility to do so.

[12] NT2 will have on-going value thereafter, but it is very far off to make a large difference to NPV and the specific utilization arrangements and comparators are too uncertain to be modeled with any confidence.

32. The three factors which could have the biggest impact on the NPV of the NT2 option are NT2 project costs,[13] the demand forecast and the value of natural gas. [14] The lower the project cost, the higher the demand forecast and the higher the value of natural gas, the more economic would be NT2. Higher demand favors NT2 because the up-take of its energy output would be faster and without NT2 there would need to be a higher rate of investment in alternative, more expensive plant. Higher gas prices favor NT2 because it is a hydro project displacing the need for an annual amount of natural gas corresponding to its energy production. The converse of these considerations also holds, and the values for all three risk factors could well vary above or below the values assumed for the base case. The cost-risk analysis recognizes that the values of these key risk factors are essentially uncorrelated and any combination of higher and lower values between them could occur, but no one knows which will actually occur. Thus, the NT2 option would be exercised knowing this uncertainty. The objective is to determine whether the option has a positive NPV (at a 10 percent discount rate) relative to the alternative decision to not build the project, taking all the tested risk values for these factors and their probabilities of occurrence (PO) into account.

33. The PO of any one combination of these factors depends on the number of possible combinations of the factors and the individual POs assigned to the high, base and low values for each factor. The resulting structure of the complete cost-risk matrix is shown in Graph 5. The base case factors are supposed to have "expected values," therefore each is assigned a PO of 50 percent (0.5). The base case project cost PO, times the base case demand forecast PO, times the base case fuel price PO has a base case PO of 0.5*0.5*0.5 = 0.125 (Graph 5, row 17). Thus, in this analysis, the case has a PO of 12.5 percent, and all departures from the base case values for these key factors a combined PO of 87.5 percent. A combination of base case project cost (PO = 0.5) but low natural gas price (PO = 0.25) and low demand forecast (PO = 0.25) has a case PO of 0.5*0.25*0.25 = 0.03125, or 3.125 percent (row 21). The POs of all cases must sum to 1.0 for each option (i.e. the option to build or not to build NT2).

34. The POs and the extent to which high and low values of the tested factors vary from their base case values are related. Small variances would normally have much higher POs than very large ones, provided the base case values have been realistically established. For this project, it is not useful to test for small variances because they would have very little impact on the value of the option, given the size and flexibility of the EGAT system and the comparative generation costs described above. Extremely large variances from base values would have very low POs, and correspondingly less importance as decision factors.

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13 Project cost is of economic interest because a formal economic benefit:cost analysis focuses on real resource costs and the efficiency of resource use, without consideration of who benefits or suffers from project cost saving or cost over-run – a distributional rather than an economic question.

14 Future CCGT capital costs are also uncertain, but the probable range and impact are considered low.

Graph 5: Structure of the Complete Cost-Risk Matrix

	A	B	C	D	E	F	G	H
1	With NT2 (the NT2 Option)					Without NT2		
2	Project	Demand	Nat Gas	PO		Demand	Nat Gas	PO
3	Cost	Growth	Value	weight		Growth	Value	weight
4	0.25	0.25	0.25	0.0156		0.25	0.25	0.0625
5	0.25	0.25		0.0313		0.25		0.1250
6	0.25	0.25	**0.25**	0.0156		0.25	**0.25**	0.0625
7	0.25		0.25	0.0313			0.25	0.1250
8	0.25			0.0625				0.2500
9	0.25		**0.25**	0.0313			**0.25**	0.1250
10	0.25	**0.25**	0.25	0.0156		**0.25**	0.25	0.0625
11	0.25	**0.25**		0.0313		**0.25**		0.1250
12	0.25	**0.25**	**0.25**	0.0156		**0.25**	**0.25**	0.0625
13		0.25	0.25	0.0313			**TOTAL>**	**1.0000**
14		0.25		0.0625				
15		0.25	**0.25**	0.0313				
16			0.25	0.0625				
17				0.1250				
18			**0.25**	0.0625				
19		**0.25**	0.25	0.0313				
20		**0.25**		0.0625				
21		**0.25**	**0.25**	0.0313				
22	**0.25**	0.25	0.25	0.0156				
23	**0.25**	0.25		0.0313				
24	**0.25**	0.25	**0.25**	0.0156				
25	**0.25**		0.25	0.0313				
26	**0.25**			0.0625				
27	**0.25**		**0.25**	0.0313				
28	**0.25**	**0.25**	0.25	0.0156				
29	**0.25**	**0.25**		0.0313				
30	**0.25**	**0.25**	**0.25**	0.0156				
31			**TOTAL**	**1.0000**				
32	**HIGH**		**LOW**					

Note: The PO of each value assumption is shown inside its respective cell.
"MEDIUM" = base case.

35. The POs and the variance at those POs are selected for this project based on two considerations: (i) experience of how the values of key factors have varied from expected values in other relevant situations; and (ii) the POs should neither over-weigh nor extinguish the expected (base) case. For example, using a 33.3 percent PO for each of the base, high and low values has the unusual implication that all outcomes are equally likely, while using 60 percent, 20 percent and 20 percent, respectively could imply over-confidence in the base case and insufficient importance to the variances there from. We have selected a 50 percent PO for base case values and a 25 percent PO each for the high and low values. The variance of each tested factor is related to those POs.

36. World Bank research on the experience of **hydropower project investment costs** suggests that a range of plus or minus 30 percent around the base case estimate is valid at 25 percent PO, and it is this consideration that determined the project cost range used in this cost-risk matrix.[15]

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15 See: Bacon, Robert W., Besant-Jones, John E., Heidarian, Jamshid: *Estimating Construction Costs and Schedules: Experience with Power Generation Projects in Developing Countries.* World Bank Technical Paper No. 325, Energy Series, 1996., and Besant-Jones, John E. "Assigning Probabilities to Scenarios for Risk Analysis – The Case of Hydropower Project Construction Costs, World Bank, May 2003.

37. ***Demand forecasting*** experience in Thailand and elsewhere suggests that at 25 percent PO, demand can be as much as 25 percentage points above or below the estimate by the tenth year into the forecast, and it is this consideration that determined the departures from base case conditions for this cost-risk matrix in respect of demand performance.[16] Electricity demand forecasts are uncertain. While the forecasting techniques may be very good, the demand for electricity is a derived demand, the underlying determinants of which are hard to predict (e.g., GDP growth, personal disposable income, household formation, commercial and industrial investment activity, and technical change). EGAT has flexibility to reschedule some planned capacity additions. A low demand forecast, 25 percentage points below the base case, results in demand growth of only 3.4 percent per year from 2002 onward. This in turn would imply extremely low economic growth – in fact stagnant per capita GDP – sustained over a long period of time. This is considered an unlikely occurrence in light of past experience over many years, save for the rather unique episode of the Asian financial crisis. However, in these conditions, the "committed capacity additions" and life-extension of old plants would have carried the system until 2013, at which point, a deficit of 222 MW would open, growing to 1,159 MW by the next year. Clearly, in those conditions, NT2 commissioning in 2009 would have been sub-optimal; its economic consequences are tested along with other uncertain factors, as described below.

38. The levels and variance of the **value of natural gas** under Thai conditions depends mainly on uncertainties about future sourcing having different cost profiles, international values of alternative fuels and the demand forecast for natural gas. The base case and lower probability cost estimates above and below the base values are stated below. The valuation basis was developed from a combination of World Bank oil price forecasts, contracting practices in the region that define mutually agreed valuation between buyers and sellers of gas and other proprietary information that natural gas producers and users in Thailand provided to the Bank, with understandings on confidentiality. The economic gas values in this table are well below commercial values for several reasons. Firstly, being economic resource costs, they exclude transfers (income taxes and royalties) on the Thai portion of the gas supply. Secondly, economic pipeline tolls are well below commercial tolls, because the economic marginal cost of gas pipeline transportation is limited to recurrent operating cost – the capital charge component for both existing infrastructure and facilities under construction being sunk costs. Thirdly, given the proven/probable reserves estimate and minimum R/P ratio adopted, extensive reliance on incremental volumes of imported gas should not begin till after the end of the system expansion period required for the least-cost analysis (2004 to 2014). Thereafter, the extent and incremental costs of imported gas or newly discovered and developed domestic gas are difficult to ascertain with confidence. These values may well understate eventual long-term natural gas economic values; if so, they more severely test the comparative economic merit of the NT2 project. The low case and high case spreads from the base case were developed by taking the lower and higher values of oil at one standard deviation from the World Bank's base case oil price forecast, working these changes through the generic contractual gas pricing formula that calculates the impact of oil price changes on gas prices, and assuming, as well, that plus or minus ten

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16 See: Besant-Jones, Sanghvi, and Vernstrom: *Review and Evaluation of Historic Electricity Forecasting Experience (1960-1985),* World Bank Industry and Energy Department Working Paper - Energy Series Paper No. 18, June 1989.

percentage points of the gas import share would be part of a low price and high price scenario, respectively, insofar as imported gas is costlier than domestic gas and assumed to remain so.

39. The base, high and low values selected for each of these three key factors are summarized as follows:

Table 3: Risk Analysis Assumptions

Assumption	Base Case	Low Case	High Case
NT2 project cost (US$mm) [a]	1,005	704	1,307
Natural gas (US$/mmbtu)	2.27	1.99	2.57
Demand Growth (%/year)	6.1	3.4	8.7

(a) Additional information on the NT2 project cost is provided below in the discussion of the ERR analysis.

40. Having determined the factors, value ranges and POs entering the analysis, the remainder of the process consists firstly of identifying the cases of particular interest to the NT2 evaluation, from amongst all those shown in the complete matrix (Graph 5). This selection is made with the following requirements in mind: [17]

(a) knowing the Base Case NPV with and without NT2;

(b) understanding the extent to which adverse values (from an NT2 perspective) put the economic worth of the project at risk; and

(c) defining the minimum conditions for the project to be part of the least-cost system expansion program relative to the next best alternative for meeting the load without the project.

41. The PV of each tested pair of cases (i.e. with and without NT2) is calculated using EGAT's system expansion planning model, and the NPV for the pair along with is probability of occurrence noted.

42. The end result is that the NT2 option has a base case PV saving of US$266 million, a minimum 86 percent probability of achieving a lower NPV cost than its natural gas-based alternative, and only an 11 percent probability of not achieving it.

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[17] Ideally one would calculate the entire matrix and emerge with one probabilistic value of the project's worth, all risks considered. However, this would have required modeling more cases than essential to understand the real economic risk profile facing this project.

Table 4: Results of Least-Cost Risk Analysis - Economic PV Savings (Economic) for the NT2 Option (US$ million)

Project Cost	Demand Forecast	Gas Price	Probability	Savings (a)
Base	**Base**	**Base**	**0.125**	**+266**
Base	Base	Low	0.063	+199
Base	Low	Base	0.063	+24
Base	Low	Low	0.031	-54
High	Base	Base	0.063	+61
High	Low	Low	0.016	-259
High	Low	Base	0.031	-181
High	Base	Low	0.031	-6
Low	Base	Base	0.063	+471
Low	Base	Low	0.031	+404
Low	Low	Low	0.016	+228
Low	Low	Low	0.015	+151

43. The base case saving is large relative to the US$682 million PV project cost. It is also a robust result, because there is only an aggregate 11 percent probability of a definite negative outcome for NT2. The base case was implemented with NT2 as a candidate (free-floating commissioning date determined by modeled optimization). The calculated optimum is 2010, indicating that the proposed commissioning date (November 2009) is appropriate. The analysis demonstrates that the economic merit of NT2 is robust, insofar as only four of the twelve downside cases tested result in negative NPV for NT2. Of the four, one of them is very close to break-even. Of the remaining three, the worst one (having a negative NPV of US$259 million) has only a 1.6 percent probability of occurrence. The remaining two are of lesser negative impact and each has only 3.1 percent probability of occurrence.

A.5 Commercial Cost-Risk Analysis

44. A parallel cost-risk analysis, undertaken using commercial[18] rather than economic values, examines whether differences in valuation of key factors, such as the demand forecast and the price of natural gas, would lead to different conclusions about the merit of the project, and hence its commercial sustainability. The main difference between economic and commercial valuation for the project cost is that in an economic analysis only the real resource cost of incremental project investment and operations is included. However, in the commercial analysis the project cost is the stream of PPA payments, which includes the recovery of sunk costs and taxes. As well, the rate of return to equity may exceed the social discount rate for the country. The main valuation difference for natural gas is that in an economic analysis only the economic value of the resource is included as discussed above, whereas in a commercial analysis the natural gas price includes royalties, taxes and market-based pipeline tolls. The results of the commercial cost-risk analysis are shown here:

[18] This valuation basis stands in contrast to the economic analysis. In the commercial analysis, the project benefit stream is the wholesale tariff the utilities pay to the NT2 project company, and power costs are limited to the commercial costs and RoR that the PPA tariff recovers (including sunk costs and taxes).

Table 5: Results of Least-Cost Risk Analysis - Commercial
PV Savings (Commercial) for the NT2 Option (US$ million)

PPA Price	Demand Forecast	Gas Price	Probability	Savings (a)
Base	Base	Base	0.250	+227
Base	Base	Low	0.125	+161
Base	Low	Base	0.125	-32
Base	Low	Low	0.063	-109

45. There is no variation of the NT2 project cost in the commercial analysis, because the PPA payments are fixed by contract. It would require low probability adverse circumstances to be sustained over a long period of time for the NT2 PPA to be seen as an inferior option. Scenarios with high demand and high gas prices were not prepared because the results of Table 5 indicate they would all have positive NPV savings for NT2. Therefore the only potential negative outcomes for NT2 are the two scenarios in Table 5 featuring a low demand forecast. The probabilities of occurrence for these scenarios range between 6.3 and 12.5 percent. Overall this means that from a commercial perspective NT2 has a minimum 87 percent probability of being sustainable in respect of the tested demand and natural gas price conditions.

A.6 Project Economic Rate of Return (ERR)

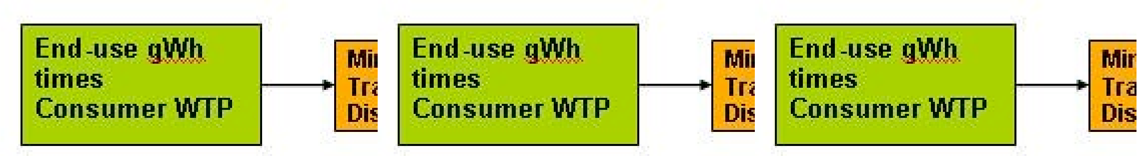
46. Once the least-cost analysis determines that the NT2 option fits as part of the least cost system expansion program, the next step is to determine whether the project has an adequate ERR.

Base Case Project ERR - Analytical Framework

47. ***The ERR analytical framework*** is designed to find the ERR of a series of annual economic costs and benefits. Benefits consist of the value of project energy to end-users. Costs include constructing and operating the project, delivering the project's energy to end-users through transmission and distribution systems and managing E&S impacts.[19] The latter are represented in the ERR calculation as a stream of E&S costs the project will pay according to the project financial model. The PV of this payment stream slightly exceeds the PV of the estimated economic E&S costs they cover.[20] The overall analytical framework may be visualized as shown in this diagram, where the left box is benefits, the next two boxes are costs and the right box is the difference between benefits and costs:

[19] The environmental and social management costs are those included in the sponsors' financial model as project costs. The PV of this payment stream slightly exceeds that of the calculated economic E&S costs.

[20] This is discussed further below. As well, please see the Report of Dr. Benoit LaPlante cited above, which describes these calculations in detail.



where: GWh = the amount of generated energy from NT2,

Consumer WTP = the price for that volume that consumers are willing to pay,
O&M = project operating and maintenance costs
E&S = environmental and social costs.

48. ***The project ERR (base case) is 16.3 percent*** (tables tabulating the base case values for key input assumptions and for benefits, costs and the ERR results are provided below and overleaf, followed by explanation of the values used). The ERR result applies to the economic net benefit flow over a thirty-year period from start of construction to the end of the PPA. The E&S costs incurred during the investment period (2005 to 2009 inclusive) are included in the investment cost data of column K, while the E&S costs incurred during the project operational period from 2010 to 2034 are included in the operating cost data of column L. A major hydro project should have a longer benefit stream. While heavily discounted, its inclusion would increase the ERR moderately. The period beyond the 30th year, however, is not included because of the uncertainty about off-take arrangements in Thailand or Lao beyond the duration of the PPA.

Assumptions

49. The following paragraphs describe the basic assumptions used in the ERR analysis.

Table 6: Summary Table of Main Benefit and Cost Assumptions

Assumption	**Value**
Thai willingness to pay (price component)	US cents 7/kWh primary energy (PE) US cents 2.3/kWh secondary energy (SE1)
Lao willingness to pay (price component)	US cents 6/kWh
Thai and Lao system losses	7.1% and 16.9%, respectively
Real Economic NT2 Project Cost	US$1,005.4 million
Present value of E&S costs paid by project	US$63.8 million
Present Value of Estimated Economic E&S Impacts	US$54.7 million
THB value loss	275 GWh at US cents 2.3/kWh, (incremental replacement cost in Thailand).
Sub-transmission and distribution costs	Thailand US cents 1.04/kWh; Lao PDR US cents 4.4/kWh

Table 7: ERR Results – Base Case

	A		B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1		16.3%	Benefits									Costs						
2			Thai PE	Thai Sec	Lao PE	Lao Sec	Thai PE	Thai Sec	Lao PE	Lao Sec	Total Ben	Investment	O&M	THB loss	Thai Dist	Lao Dist	Total Cost	Net
3		Year	GWh	GWh	GWh	GWh	USDmm	USDmm	USDmm	USDmm	USD mm	1005.4		0.023				Benefit
4	2004	1										74.4					74.4	-74.4
5		2										167.3					167.3	-167.3
6		3										212.6					212.6	-212.6
7		4										237.5					237.5	-237.5
8		5										196.0					196.0	-196.0
9		6										110.1					110.1	-110.1
10	2010	7	4,406	948	160		287.4	21.8	7.7	0.0	316.9	7.4	18.0	6.3	42.5	5.8	80.1	236.8
11		8	4,406	948	175		287.4	21.8	8.4	0.0	317.6		18.0	6.3	42.5	6.4	73.2	244.4
12		9	4,406	948	190		287.4	21.8	9.2	0.0	318.3		18.0	6.3	42.5	6.9	73.7	244.6
13		10	4,406	948	200		287.4	21.8	9.7	0.0	318.8		18.0	6.3	42.5	7.3	74.1	244.7
14		11	4,406	948	200		287.4	21.8	9.7	0.0	318.8		17.3	6.3	42.5	7.3	73.3	245.5
15		12	4,406	948	200		287.4	21.8	9.7	0.0	318.8		16.7	6.3	42.5	7.3	72.7	246.1
16		13	4,406	948	200		287.4	21.8	9.7	0.0	318.8		16.7	6.3	42.5	7.3	72.7	246.1
17		14	4,406	948	200		287.4	21.8	9.7	0.0	318.8		16.7	6.3	42.5	7.3	72.7	246.1
18		15	4,406	948	200		287.4	21.8	9.7	0.0	318.8		22.9	6.3	42.5	7.3	79.0	239.8
19		16	4,406	948	200		287.4	21.8	9.7	0.0	318.8		22.9	6.3	42.5	7.3	79.0	239.8
20		17	4,406	948	200		287.4	21.8	9.7	0.0	318.8		22.9	6.3	42.5	7.3	79.0	239.8
21		18	4,406	948	200		287.4	21.8	9.7	0.0	318.8		22.9	6.3	42.5	7.3	79.0	239.8
22		19	4,406	948	200		287.4	21.8	9.7	0.0	318.8		16.7	6.3	42.5	7.3	72.7	246.1
23		20	4,406	948	200		287.4	21.8	9.7	0.0	318.8		16.7	6.3	42.5	7.3	72.7	246.1
24		21	4,406	948	200		287.4	21.8	9.7	0.0	318.8		16.7	6.3	42.5	7.3	72.7	246.1
25		22	4,406	948	200		287.4	21.8	9.7	0.0	318.8		16.7	6.3	42.5	7.3	72.7	246.1
26		23	4,406	948	200		287.4	21.8	9.7	0.0	318.8		16.7	6.3	42.5	7.3	72.7	246.1
27		24	4,406	948	200		287.4	21.8	9.7	0.0	318.8		16.7	6.3	42.5	7.3	72.7	246.1
28		25	4,406	948	200		287.4	21.8	9.7	0.0	318.8		16.7	6.3	42.5	7.3	72.7	246.1
29		26	4,406	948	200		287.4	21.8	9.7	0.0	318.8		16.7	6.3	42.5	7.3	72.7	246.1
30		27	4,406	948	200		287.4	21.8	9.7	0.0	318.8		16.7	6.3	42.5	7.3	72.7	246.1
31		28	4,406	948	200		287.4	21.8	9.7	0.0	318.8		22.9	6.3	42.5	7.3	79.0	239.8
32		29	4,406	948	200		287.4	21.8	9.7	0.0	318.8		22.9	6.3	42.5	7.3	79.0	239.8
33		30	4,406	948	200		287.4	21.8	9.7	0.0	318.8		22.9	6.3	42.5	7.3	79.0	239.8
34		31	4,406	948	200		287.4	21.8	9.7	0.0	318.8		22.9	6.3	42.5	7.3	79.0	239.8
35	source >		inputs D133	inputs E133	inputs F133	inputs G133											ERR >>	16.3%

50. ***Project benefits*** (Table 7, columns B to J) include the value of NT2 sales at the Primary Energy (PE) and Secondary Energy 1 (SEC1) tariffs to Thai and Lao electricity consumers.[21] Sales at the Secondary Energy 2 (SEC2) tariff are excluded because the amounts are very uncertain and of low value.[22] The following paragraphs explain the derivation of end-user value and losses.

51. ***The price component of Thai consumer willingness to pay (WTP)*** estimates for PE for the MEA and PEA distribution systems individually and the two combined. WTP includes what customers actually paid for their electricity in 2004, i.e., revenue per kWh sold including value-added tax (7 percent), amounting to THB 2.81/kWh or US cents 7/kWh. This value does not include any estimate of "consumer surplus" (i.e. the prices times the quantities of energy that consumers would have been willing to use at prices above the tariff). As such, it moderately underestimates the potential true economic value of the benefit stream, and likewise the project ERR. The value for SE1 is its energy displacement value in the EGAT production merit order, estimated at US cents 2.3/kWh for fuel and variable O&M. Being secondary energy, it is not serving incremental capacity and energy needs. Rather it displaces energy that would otherwise be produced from existing capacity serving existing demand.

52. ***Lao WTP*** is US cents 6/kWh in 2004, based on information from the recently completed Elektrowatt tariff study.[23]

53. To calculate ***System losses (Thailand) for transmission and distribution*** it is necessary to reduce the benefits of NT2 energy production by losses, because all power systems have transmission and distribution losses between the power plant and points of end-use, reducing end-use consumption relative to generation. Thailand's loss rates (average of 7.1 percent for transmission and distribution) indicate a power system operating at very high technical and commercial efficiency.[24]

54. ***System losses (Lao PDR)*** are now about 17 percent, the split between technical and non-technical losses being unknown. Elektrowatt maintains this loss factor over its planning period.

55. ***Total benefits*** are the sum of PE and SEC1, shown in Column J of Table 7.

56. ***Project investment costs*** are shown in column K. The source of all the raw cost data in this table, excluding the transmission line from the Thai border to the Thai grid, is the version of the sponsor's financial model from December 2004. Adding all of the individual components yields

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21 Looking at "Benefits" in the Base Case Table, columns B and C are the expected annual sales of PE and SEC1 energy to EGAT (and likewise in columns D and E for sales within Lao PDR). The values of PE and SEC1 to Thailand are listed in columns F and G respectively. The formula for the PE benefits calculation is (GWhPE * (1-percent losses)*end-user value per unit).

22 The sponsors' financial model also excludes SEC2 for the same reasons.

23 "EDL Tariff Study Final Report," December 2004, Electrowatt-Ekono Ltd., Switzerland and Fichtner, Germany

24 Thailand has negligible non-technical losses and a fully commercial billing and collections profile.

a nominal project cost of US$1,216.5 million.[25] The total includes the head contract, financing costs, development costs, insurance, and pre-commissioning operational, environmental, social and contingency costs.[26]

57. Some adjustments are needed to convert the financial values in the financial model to economic values for use in an ERR calculation. Firstly, over US$250 million of IDC is not explicitly accounted because the time value of the annual cash flow is internalized in the ERR calculation. Secondly, US$7.5 million of NTPC's contribution to the GOL of US$30 million is excluded because it refunds sunk costs.[27] Thirdly, US$85 million of pre-closure sunk development costs and financing contingency at sponsor risk are excluded. Fourthly, because the costs are in fixed-price contracts, but expended gradually over 54 months, it is known that contractors included expected inflation in the contract prices that the cost data reflect. Therefore, it is necessary to convert the nominal costs to the project evaluation numeraire of real US$ (2004). This is done using the World Bank's MUV index.[28] The economic project cost after these adjustments is US$1,005.4 million, including US$135 million for the Thai portion of the NT2-associated transmission line. The adjustments from financial to economic project cost are shown in the following summary table:

Table 8: NT2 Project Cost Adjustments from Financial to Economic Values

	A	B	C	D	E	F
1	**1. Project Cost Provided in Financial Model**	USDmm				
2	1.1 Developmental Pre-Op (incl. GoL contribution)	251.1				
3	1.2 Head contract costs	704.5				
4	1.3 Financing costs	261.0	check			
5	**Total Financial Cost**	**1,216.5**	1,216.5			
6						
7	**2. Conversion to Economic Cost**					
8	2.1 delete financing costs	-261.0				
9	2.2 delete sunk costs & finance contingency from 1.1:	-84.9				
10	2.3 delete portion of GoL contribution	-7.5				
11	**Total nominal cost of economic items:**	**863.2**	0.00	nom error		
12	Adjustment from nominal to real economic items values	7.3	0.00	econ error		**TOTAL**
13	**Total real cost of economic items:**	**870.4**	**plus>**	**Thai TRS**	135.0	**1,005.4**

58. Generation-associated transmission in Lao PDR from the project to the grid is included in the project investment cost.

59. ***Project Operations and Maintenance (O&M) costs***, post-commissioning (column L) are from the sponsors' financial model. They include E&S management costs (area management, resettlement, monitoring and contingencies), NTPC administration and insurance costs, project operations and major maintenance. They are denominated in US$ and THB, the two main project

[25] Since this work was completed the sponsors have increased the nominal project cost to about US$1250 million. It was neither possible, nor would it have been of any consequence, to redo all of the economic analyses for such a small change.

[26] Additional contingencies have been negotiated between NTPC and the lenders amounting to US$200 million, the purpose being to assure debt service in the event of about a one-year revenue lapse for whatever reason. We evaluate this risk by assuming a one-year absence of benefits after project commissioning, rather than adding this financial contingency to the project cost.

[27] Both these adjustments are standard methodology.

[28] This index is applied to total economic costs denominated in US$ after the THB portion of costs is converted to US$ at THB 40 per US$1.

currencies. The THB costs are first converted to US$ at THB40 per US Dollar. Aggregate nominal US Dollar costs are then converted to real US Dollars of 2004 using the MUV deflator. For the E&S component of O&M costs, being "harder" numbers, we have retained these expected project payout costs in the ERR calculation, although they are slightly higher than the calculated economic value of the associated impacts. Using either would not alter the ERR noticeably.

60. When NT2 is commissioned, there will be a 275 GWh reduction of firm export energy from the Theun Hinboun project. This is valued at US cents 2.3/kWh, being the cost of replacing it with CCGT energy from existing capacity in Thailand.

61. ***Thai Distribution Costs*** are based on a forward projection of distribution system Long Run Average Incremental Cost (LRAIC) in Thailand. MEA and PEA, the two Thai public sector distribution utilities, provided their projections of incremental energy sales and investment programs over 2002 to 2011 and 2008, respectively.[29] To calculate the LRAIC of investment, the incremental sales volume is stabilized at the value reached by the end of the expansion program and accounted over the number of additional years needed to complete a roughly 35 year economic life cycle for the incremental investments. The nominal investment values over the expansion phase are deflated to real THB levels using a projected THB CPI deflator of 2.8 percent per year[30] then converted to US$. A discount rate of 10 percent is used to represent the social discount rate for Thailand. The present values of the annual investment program are divided by the present values of the incremental GWh sales to end-users for the two systems, yielding LRAIC of US cents 0.57/kWh. Recurrent operating costs of the incremental investments are based on the operational experience of 2001 plus a projection of long-term real productivity improvement of 1.5 percent per year for the next ten years,[31] resulting in a real value of US cents 0.45/kWh. Combining investment and operating costs, the LRAIC of distribution is US cents 1.04/kWh. This value is multiplied by PE sales to end-users, resulting in total incremental distribution costs for NT2-associated sales.

62. ***Transmission and distribution costs within Lao PDR. For transmission*****,** the nominal cost estimate of US$14 million per year for two years (provided by Lahmeyer) is deflated to real dollars assuming transmission works would begin two years before project commissioning. We assume that operating costs of the transmission line would be 1 percent of investment, and losses from the project to end-users 16.9 percent. Sales to the Lao system may range between 200 and 300 GWh per year, but we have used the sales stream committed in the PPA, which is 200 GWh, then adjusted for losses. The PPA requires that 200 GWh be supplied, but EDL has the option to take up to 300 GWh.

63. ***Estimates of LRAIC distribution costs (Lao PDR)*** are based on estimates which Elektrowatt developed in the tariff study for region CR-2, where NT2 energy will be absorbed.

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[29] All of this data was re-verified with the utility's up-dated planning data for 2004-2011, based on a higher demand forecast. The results in terms of cost per kWh are extremely close, however the earlier series is retained, because it reflects the demand forecast in this study and results in very slightly higher unit cost.

[30] Based on experience of 1997 to 2001.

[31] The regulation of distribution tariffs includes an RPI-X formula. The actual values for X over the next ten years are not known. However, an assumption of 1.5 percent per year real productivity improvement over the next ten years is reasonable, especially in light of the scope for operational efficiency improvement being considered in the context of further sector reforms under discussion.

Combining the per kWh end-use cost of incremental transmission and distribution, the total is US cents 4.4/kWh.

64. ***Environmental and Social Costs*** are maintained as those expended according to the incremental cost data in the sponsors' financial model, it being shown in the above summary table of input assumptions that the accounted economic E&S are about US$9 million (PV) lower than the planned project outlays. Thus, this analysis retains the higher cost valuation. Please see the Section at the end of this Annex for an expanded summary discussion of environmental and social costs.

65. ***Total costs*** (ERR Base Case Table Column P) are the sum of project investment, O&M, transmission and distribution costs per year from 2004 to 2034.

66. ***Net benefit*** per year (ERR Base Case Table Column Q) is the difference between total benefits (Column J) and total costs (Column P). The ERR to the net benefit stream in the base case is 16.3 percent (real).

Sensitivity Analysis

67. ***Sensitivity tests*** are conducted to evaluate the impact on the ERR of project delay, cost over-run, low demand (the Thai system low load growth rate assumed in the cost-risk analysis), hydrological distress in 2010 and 2011 equivalent to the worst two hydrological years on record (notwithstanding sponsor assurance of near-certainty that the reservoir will be filled before commissioning), and various combinations of these adverse circumstances. The one-year delay scenario is portrayed as a situation in which the sponsors have committed to the financing and the contracts on the original project schedule, but there is a twelve- month delay in the project commissioning date, resulting in zero benefits for that twelve months. The two-year delay scenario includes a reshaping of the cash flow by spreading it proportionately over the construction period such that the same total is fully expended at the end of an additional two years.

68. Cost over-run is tested for: (i) a total over-run of 10 percent proportioned over the original cash flow distribution of the NT2 investment stream; and (ii) a 30 percent cost over-run. The impacts of these tests are shown notwithstanding that the base project cost already includes a contingency ("risk premium" in the head contract), it also being likely that the estimated costs of the subcontracts include contractor contingencies (of unknown amounts) because they will be lump sum, time bound, fixed price contracts, with exceptional provisions as negotiated between NTPC and the subcontractors.

69. A summary of the ERR results is as follows:

Table 9: ERR Results – Base Case and Sensitivity Tests

Scenario	ERR	Notes
1. Base Case	**16.3%**	Planned commissioning date, base case costs
2. Returns delayed one year	14.6%	Base case investment, but one year commissioning delay
3. 10% Project Cost Over-run	15.1%	Economic costs increased pro-rata 10% in each year
4. Cases 2 & 3 combined	13.5%	
5. Low Demand	12.8%	2010 commissioning, but secondary energy value for 3 years
6. Case 5 & 30% cost over-run	10.5%	
7. Two year delay	13.8%	Re-shaping of investment cash flow; no PPA extension
8. Case 7 & 30% cost over-run	11.1%	
9. Two driest years	15.7%	Base case with reduced energy 2010, 2011 (per NTPC)

The worst case scenario, combining low demand growth with a 30 percent cost over-run still does not bring the ERR below 10 percent.

A.7 Summary: Economic Value of Environmental and Social Impacts

70. Environmental and social impacts of the project differ significantly across the various impacted areas of the project.

71. ***In the Nam Theun River basin*** (downstream of the Nakai dam), impacts are expected to be limited to the loss of fisheries (resulting from a reduction in water flow). Estimates of aggregate fisheries loss range from US$0.73 to US$1.30 million PV. These losses are expected to be fully mitigated by the project. The estimated cost of this mitigation program is expected to range between US$0.8 and US$1.6 million PV (depending on the timing of program implementation). No additional adverse impacts are expected on human-related use of the water of the Nam Theun River. Species recorded on the transects of the Nam Theun River are common in the surrounding forest environment, and the riparian vegetation of the Nam Theun River is commonly recorded over a wide geographic scale of the Nam Theun River Basin. However, one notable exception to the above observation is the big-headed turtle (*Platysternon magacephalum*) which has thus far been observed only within the river valley and whose existence may be threatened by the reduction in water flow.

72. ***The Nakai Nam Theun NPA*** is nationally and internationally recognized as one of the most important biodiversity sites in Southeast Asia. The protected area is currently under severe stress as a result of both legal and illegal activities. It has also been recognized that the current rate of harvesting of high value products is unsustainable, and that the wildlife and biodiversity are under serious threat. Within the protected area itself currently live approximately 1,200 households (about 5,800 people) with an average level of total annual household income of approximately US$400.

73. The commitment of US$1 million per year for protection and management of the NT2 watershed for the duration of the concession agreement by NTPC is expected to generate key positive benefits, including improving natural resources management, protecting and conserving the habitat and biodiversity of the NNTNPA, improving the livelihood of its inhabitants, contributing to poverty alleviation (it is estimated that the project will reduce poverty by up to 35 percent in the NPA), and preserving the ethnic diversity found in the NNTNPA. Set against scenarios whereby logging activities in the NPA would intensify, the benefits of maintaining the

carbon sequestration services of the NPA are estimated between US$10 to US$20 million PV. None of these benefits are expected to be realized in the absence of the project.

74. ***The flooding of the Nakai Plateau*** entails both local and global costs and benefits. The project, through its livelihood program will significantly contribute to poverty alleviation for the resettlers by doubling the expected present value of aggregate income (from US$5 to US$10 million PV), and by completely alleviating poverty of the resettlers (as measured against the Lao poverty line). The project will further significantly increase access to improved health care and education facilities, water supply, sanitation, and electricity.

75. ***Green-house Gas Emissions (GHG).*** The project is expected to reduce emissions of GHG by approximately 20 million tons over the horizon of the analysis (avoided emissions of 50 million tons compared to CCGT partially offset by an estimated 30 millions tons of emissions from the reservoir itself). Net benefits from reduced GHG emissions are estimated between US$4 and US$16 million PV depending on the timing of the release of GHG from the reservoir.

76. ***Wildlife and Biodiversity*****:** Existing information does not support the notion that the impacted area (Nakai Plateau and resettlement area) is of high biodiversity value. The white winged duck may benefit from the project as the impoundment of the Plateau will lead to an expansion of forested wetlands. The habitat of the Asian elephants is expected to be adversely impacted by the project, though not to the point of threatening the viability of the elephants in the area. For both of these species, conservation programs will be put in place by the project to facilitate their adaptation to the new environment.

77. **The *Xe Bang Fai River basin*** will experience both positive and negative impacts. Adverse impacts include mainly loss of fisheries, the loss of river bank gardens, and the loss of assets including potentially cultural sites. The largest of these adverse impacts pertain to the loss of fisheries income (cash and imputed) estimated at approximately US$4 million PV. The lower XBF may also experience additional flooding which may significantly impact productive rice yield. Estimated expected loss may reach US$3 million PV. All known adverse impacts of the project are expected to be completely mitigated or compensated for through the implementation of a program that will offer riparian inhabitants with alternative livelihood options, and the relocation of all productive and physical assets.

78. **The *Mekong River,*** including Cambodia's Great Lake (the Tonle Sap) and floodplains are not expected to experience any significant impact. This analysis is covered in the Cumulative Impact Assessment (CIA) prepared for the project.

79. ***Induced impacts*** are expected to be significantly positive, especially the increased potential for irrigated agriculture in the XBF River Basin, and additional tourism activities in the area of the reservoir. Estimates show potential revenues in the order of US$4 to US$6 million PV over the lifetime of the project.