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Trung Son Hydro Project

Economic Analysis

Final Report

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Contents

Abbreviations and acronyms

ACT	Avoided cost tariff
CCCT	Combined cycle combustion turbine
CGM	Competitive generation market
cif	cost insurance freight
cumec	cubic meter per second
DSCR	debt service cover ratio
dwt	dead weight tons
ERAV	Electricity Regulatory Authority of Vietnam
ERR	economic rate of return
FFA	forward freight agreement
FIRR	financial internal rate of return
fob	free-on-board
FOREX	foreign exchange
FRL	full reservoir level
FS	feasibility study
HWL	high water level
IDA	International Development Association
IoE	Institute of Energy
IPCC	International Panel on Climate Change
JCC	Japan crude cocktail
JSC	joint stock company
LDU	Local distribution utility
LIBOR	London Inter-bank Offer Rate
LRMC	long-run marginal cost
MCM	Million cubic metres
MER	market exchange rates
MoF	Ministry of Finance
MoIT	Ministry of Industry and Trade
MWL	minimum water level
OCCT	open cycle combustion turbine
OLS	ordinary least squares
ORB	OPEC reference basket
PC	power company
PMDP-6	Power Master Development Plan 6
PECC4	Power Engineering Consulting Company 4
PPP	purchase power parity
RESPP	renewable energy small power producer
SGD	Singapore dollars
SCC	social cost of carbon
SPPA	standardised power purchase agreement
WACC	weighted average cost of capital
WTI	West Texas Intermediate (crude oil)
WTP	willingness to pay

1 Introduction

1. The proposed 260 MW Trung Son hydro project is located on the Ma River in Thanh Hoa province. It rises in Dien Bien province to the Northwest, but then enters the territory of Laos before returning to Vietnam in Thanh Hoa (Figure 1.1). Of the 13,175 km^2 of total catchment area, 8,500 km^2 is in Vietnam. Only the hydro-meteorological data available from Vietnamese territory has been used for the project design. [1]

Figure 1.1: The Trung Son Catchment Basin

Source: PECC4 *Specialised Report of Sedimentation and Surge Water Calculations*, FS, Volume 2.2

2. The project is designed for daily peaking, and has a relatively small reservoir for its installed capacity: its power density is 19.8 Watts/m^2, well above the threshold at which methane emissions from the reservoir are considered to be an issue.[2] During the wet season the reservoir is operated at a lower level so as to provide flood storage. The salient features of the project are shown in Table 1.1.

[1] According to PECC4, there is only a single temperature and rainfall station in the territory of the Lao PDR, about 50 km upstream.

[2] Carbon accounting issues are discussed further in Section 4.

Table 1.1: Salient features of the Trung Son hydro project

	units	
installed capacity	MW	260
firm capacity	MW	41.8
average annual energy (gross)	GWh	1,019
load factor	%	46.4
own-use	%	0.075%
Reservoir & Hydrology		
active storage	MCM	112.1
dead storage	MCM	236.4
total storage	MCM	348.5
average annual inflow	cumecs	235
design flow	cumecs	503.8
head range	metres	71.1-54.20

Source: PECC4, *Hydropower-Energy Economy*, Book 2A, March 2008

3. Trung Son is among the few remaining large hydro projects in Vietnam – thereafter only Lai Chau (1,200 MW) has a higher installed capacity, though there are a number of larger hydro projects dedicated to the Vietnam system planned for Laos and Cambodia (Table 1.2)

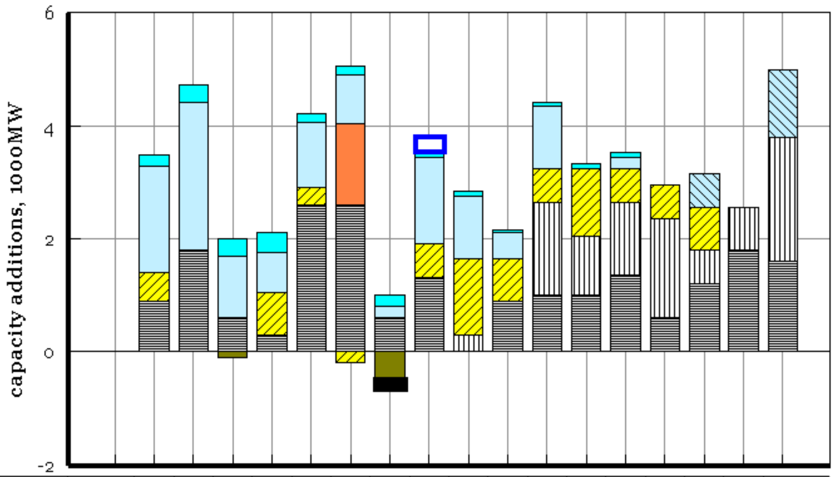
Table 1.2 Hydro projects in the least cost expansion plan[3]

	MW		
2014	68	Khe Bo	
2014	78	Dong Nai 5	
2014	436	Sekaman1	Lao PDR
2014	120	A luoi	
2014	220	Upper KonTum	
2014	28	Srepok 4	
2014	100	Nam Mo	Lao PDR
2015	170	Dong Nai 5	
2015	540	Hoi Xuan	
2015	210	Dak Mi 4	
2016	**260**	**Trung Son**	
2016	126	Song Boung2	
2016	431	Sekong 5	Lao PDR
2017	222	Lower Srepok 2	
2017	**1200**	**Lai Chau**	
2017	210	Dak Mi 1	
2017	375	Lower Se San 3	Cambodia
2017	207	Lower Se San 2	Cambodia
2018	85	Song Buong 5	
2019	195	Hua Na	
2019	53	Hieu River	
2020	229	Nam Kong 1	
2021	96	Ban Uon	
2021	260	Bao Lac	
2021	250	Nho Que 1, 2	
2023	200	Nam Na	

[3] As determined by Institute of Energy (IoE), based on the World Bank load forecast (see Annex 3).

4. Trung Son is part of a power development strategy that emphasizes the development of Vietnam's remaining hydro resources in the short to medium term, before turning to imported coal in the longer term, with additional peaking power provided by pumped storage. This strategy is dictated by resource constraints on domestic coal (anthracite in the North) and on natural gas (in the South). Indeed, over the past decade, most of the capacity additions in Vietnam have been domestic coal in the North, and natural gas in the South (with the development of the CCGT complexes at Phu My and Ca Mau).[4] Figure 1.2 shows Trung Son's place in the least cost capacity expansion plan.[5] Net capacity retirements are shown as negative entries.[6]

Figure 1.2: Trung Son in Vietnam's capacity expansion plan (World Bank load forecast)



	2009		2011		2013		2015		2017		2019		2021		2023		2025
coalSteam	0.9	1.8	0.6	0.3	2.6	2.6	0.6	1.3	0.0	0.9	1.0	1.0	1.4	0.6	1.2	1.8	1.6
coalSteamI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	1.7	1.1	1.3	1.8	0.6	0.8	2.2
CFB	0.0	0.0	0.0	0.0	0.0	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
gas	0.5	0.0	0.0	0.8	0.3	-0.2	0.0	0.6	1.4	0.8	0.6	1.2	0.6	0.6	0.8	0.0	0.0
hydro	1.9	2.6	1.1	0.7	1.2	0.9	0.2	1.5	1.1	0.5	1.1	0.0	0.2	0.0	0.0	0.0	0.0
hydroPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	1.2
SHP/RE	0.2	0.3	0.3	0.3	0.1	0.1	0.2	0.1	0.1	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0
nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
oil,CT, other	0.0	0.0	-0.1	0.0	0.0	0.0	-0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
oldCoalretire							-0.2										
Trung Son hydro								0.26									

Note: "Coal Steam" is domestic anthracite; " coalSteamI" is supercritical imported coal

[4] World Bank, *Vietnam Power Strategy: Managing Growth and Reform*, 2006

[5] The sensitivity of the Trung Son investment decision to load forecast uncertainties is also discussed in Annex 3.

[6] The coal retirements are 4 x22 MW at Ninh Binh and 2 x50 MW at Uong Bi, all in 2015; the other proposed retirements include 70 Mw of small PC2 diesels in 2011; and the fuel oil/diesel plant at Thu Duc in 2015.

1.1 Methodology

5. In order to finance a major power project, it has been general World Bank practice to require a demonstration that a proposed project is in the "economic least cost plan" – generally by exercising a capacity expansion optimisation model under a set of exogenous assumptions about reliability (loss of load probability), load forecast to be met, capital costs of alternative options, and fuel prices. Such a model (WASP-Strategist) is available for Vietnam at the Institute of Energy (IoE),[7] and we summarise in Annex 4 the results of the least cost planning study prepared by IoE for the Trung Son appraisal.

6. A range of difficulties arise in such studies. The first, and most important, is that an expansion plan is "optimal", i.e. least cost, only for the particular set of exogenous assumptions provided. But in the modern world many of these critical assumptions are subject to much uncertainty and increasing volatility – as evidenced by the oil price boom of 2007-2008 followed by the price collapse of 2009, or by the uncertainties of a demand forecast where a significant part of the load is driven by the health of export industries subject to the vicissitudes of the global economy.

7. The 6th Power Master Development Plan (PMDP-6) commits Vietnam to developing its remaining hydro resources before turning to imported coal (and possibly nuclear) – a strategy of which Trung Son is part. Given the very large range of future world oil prices (to which the price of imported coal and LNG is linked), the question is under what circumstances would this strategy be more costly than one based on fossil fuel generation – indeed, if oil were to return to the 20-30$/bbl price range for any length of time, fossil fuel generation might be preferred to a capital intensive hydro project. If such a scenario seems improbable, one need only recall July 2008, when oil stood at $140/bbl, at which point many considered unthinkable a price collapse to the early 2009 price range of 40-50$/bbl.

8. Most important is the idea of hydropower as a hedge. Once a large hydropower project is built, the cost of electricity from that project is locked in (though subject to year-on-year hydrological variations, but whose reversion to the mean is subject to well established laws of probability).[8] Once built, even if it turns out that demands are lower than

[7] This model, and the general planning procedures used by IoE for the preparation of the 6-th Power Development Master Plan are reviewed in D. Wilson, *Review and Assessment Report for the Development of Least-Cost Planning and Implementation Procedures for the Vietnam Competitive Generation Market*, Report to ERAV, August 2008; and in Mario Pereira, *Review of Power System Expansion Planning in Vietnam,* Report to the World Bank, June 2008.

[8] Assuming no long term changes in inflows due to climate change – a subject discussed in Section 3.

expected, Trung Son would still be run to its full hydrological potential, with the result that coal and natural gas generation projects would be backed down, and therefore the avoided GHG emission benefits would be unaffected.

1.2 Assessing benefits

9. The main benefits of the Trung Son power project are power and energy. These can be assessed in several different ways.

- *Incremental benefits*: this approach evaluates the benefits as the area under the consumer's demand curve (willingness to pay, WTP). In the case of industrial and commercial consumers, the WTP is assumed given by the cost of captive generation by diesel generators (for which one might assume 5MW diesels powered by fuel oil for industry, and 100kW generators powered by gasoil for commerce. For households, the demand curve is typically estimated on the basis of household energy surveys - where willingness to pay for the first tranche of electricity for lighting and TV may exceed 1$/kWh (as revealed by high expenditure by non-electrified households on candles, dry cells and kerosene), but then declines as consumption for other appliances grows). There are two main disadvantages to this approach: household electricity surveys, when available, are not very reliable (particularly in remote areas); and one must also estimate the associated incremental costs of transmission and distribution required to bring the incremental power to the consumer.
- *Avoided costs*: this approach evaluates the benefits as the avoided economic costs. It treats the benefits as "non-incremental" – meaning that in the absence of Trung Son, some other project would in fact be built. This requires assumptions about the economic value of the thermal energy that is displaced at the margin (mainly coal and gas), and the value of avoided thermal *capacity*. The economic value of these fuels which are considerably higher than the subsidized financial value cost paid by EVN. The approach has the merit of transparency, and the sensitivity of economic returns to assumptions is easily established.
- *Least cost planning models*: Another approach is to run a least cost capacity expansion planning model, whose objective function is minimization of the present worth of system costs to meet the load forecast under specified reliability constraints. The benefit of Trung Son is given by the difference in objective function values with and without the project. These models are complex, difficult to run[9], and generally lack transparency.
- *Imputing Benefits from market prices. E*conomic benefits could also be assessed at market prices: Vietnam is committed to market reforms, and by the time Trung Son comes into operation, the competitive generation market (CGM) is expected to be in place. The prices for energy and capacity in such a competitive market would by definition be suitable for

[9] The STRATEGIST model that is used by IoE requires several days for one run.

the valuation of the economic benefits – albeit subject to a correction to account for the avoided environmental damage costs.

But this approach encounters two difficulties. The first is that at the time of writing, the system is not yet in place, so prices can only be estimated. Moreover, the consultants advising on power market design have yet to complete a market simulation model that could provide guidance on the likely evolution of market prices. The second difficulty is that even if the market were to provide competitively determined energy prices, capacity prices would likely be determined by the regulator. But as has emerged in several Latin American countries with competitive markets not unlike that being proposed for Vietnam, regulatory determination of capacity charges is subject to a set of its own controversies and uncertainties.

10. The economic returns of the Trung Son project are evaluated using the avoid cost approach, and confirmed by running IoE's least cost planning models with and without the project (an evaluation that is described in the companion report on Trung Son alternatives).[10]

1.3 Alternatives to the project

11. The general question of alternatives to Trung Son examined in this report has four parts:

- Could the need for additional peaking power be met by more aggressive energy conservation, demand side management and transmission and distribution (T&D) loss reduction? In other words, is there a need to expand supply at all?

- Given that Vietnam does indeed need to add capacity, what is the optimum supply side expansion strategy, and does it include hydro? Put another way, is there a cost-effective alternative to the strategy of developing hydro as the best source of peaking power?[11] The reasonable alternatives are gas in some combination of open and combined cycle generators, possibly using imported liquefied natural gas (LNG); and pumped storage (in combination with either nuclear or coal).

- Given that hydro is indeed the best option for peaking power, how does Trung Son compare to other hydro options? Are there more

[10] World Bank, *Alternatives to the Trung Son Hydro Project*, December 2009.

[11] Environmental considerations may constrain operation as a pure peaking project because ramp-up times are constrained (which should not exceed increases in stream flow rates experienced under natural conditions), and because of the minimum downstream flow requirement. However, detailed studies show that the contribution of the capacity credit to the total economic benefit is modest, and that ramp-up constraints have a correspondingly small impact on the economic returns (see Section 2.2).

attractive hydro projects that should be built in its place (or built before Trung Son)? Would imports from Laos, Cambodia or China be more attractive (lower costs or lower environmental impacts)?

- Given that a hydro project in the Trung Son section of the Ma river is the best option, what specific site alternatives are available, and what are the general alternatives for project configuration (particularly with respect to high water elevations and environmental and social impacts of the project alternatives)?

12. Some further engineering design questions that are of negligible impact on environmental and social impacts are not discussed here: these are covered in the detailed feasibility and engineering studies.

Alternatives To Supply Side Expansion

13. The proposition that Trung Son might not be needed because alternatives to supply side expansion could meet the incremental demand, cannot be sustained. Given Vietnam's need for economic development, the increasing demand for electricity in general, and peaking supply in particular, simply cannot be accommodated by demand side options alone Moreover, unlike many South Asian countries, T&D losses are already quite low, and the present strategy already includes significant expenditures to bring this down from around 11% presently to 9%. With one or two exceptions, the efficiency of Vietnam's thermal projects is good, and the older ones (such as the Pha Lai 1 and Uong Bi coal projects) will either be rehabilitated or retired by 2015 – measures that again are already envisaged in the power development plan.

14. The same is true of DSM. EVN has embarked on an ambitious DSM program (including a CFL program, and a major initiative to improve commercial energy efficiency). The same is true of small renewable energy projects: several recent reforms (such as the introduction of a standardized power purchase agreement and a published avoided tariff, and the World Bank supported Renewable Energy Development program) are expected to enable the ambitious 6th Power Development Plan for around 1,500 MW of small hydro and other renewables by 2015. In short, while all of these alternatives to supply side expansion are unquestionably desirable, they are already under implementation, and simply do not represent an alternative to Trung Son: *both* are needed.

Hydro in the Optimum Capacity Expansion Strategy

15. All power systems require peaking projects, and if hydro projects were not built, the likely alternative is natural gas based combined cycle projects. Not only does this imply additional greenhouse gas emissions, it incurs significantly higher costs, particularly were gas priced at international levels (which means a gas price equivalent to about 90% of the Singapore fuel oil price). Even when gas is priced at the Ca Mau pricing formula, at 45% of the fuel oil price, developing Vietnam's

remaining hydro projects bring significant economic benefits. In short, at capital costs of below $2,000/kW, hydro projects are win-win, bringing significant avoided GHG emission *and* economic benefits. In addition, reducing the dependence of imported fossil fuel by developing indigenous renewable energy resources improves energy security through greater supply diversity.

16. A study of the national hydropower development plan by the Stockholm Environmental Institute confirms these arguments. Based on a series of capacity expansion scenarios with progressively less hydro it finds the costs of ***not*** developing the hydro projects presently identified in Vietnam's 6th Power Development Plan as prohibitively expensive. This is true even when all indirect costs are quantified, such as the economic loss of forest products from the inundated area. Indeed, the economic analysis of Section 5 follows all of the SEI recommendations on internalising environmental and indirect costs in the benefit-cost assessment.

Alternative Hydro Projects to Trung Son

17. Trung Son is one of many potential hydro projects in the remaining inventory of candidates, which raises the question of whether there are better hydro projects than Trung Son, which might in turn lead to Trung Son being delayed in favour of other projects, including projects in Laos and Cambodia. This question is answered in two parts. First, when all of the uncommitted hydro projects are provided as candidates to a capacity expansion optimisation, Trung Son is built first (and before the Lai Chau project): as noted, a summary of the results of these studies conducted by the Institute of Energy is provided in Annex 4.

18. Second, when one compares Trung Son against all of the other potential hydro projects on the basis of the main environmental attributes (loss of forest, persons displaced, power density, cost of energy), the high ranking of Trung Son is confirmed. In short, given that the overall strategy requires the development of Vietnam's remaining economic hydropower resource endowment, Trung Son is one of the most attractive projects within that strategy.

Alternative project sites and reservoir configurations

19. The Master Plan for the Development of the Ma river has considered a range of sites and development options. The subsequent evaluation of alternative Trung Son project configurations was based on a trade-off analysis between optimal hydro production on the one hand, and environmental and risk considerations on the other – including minimization of geotechnical risks, minimizing the number of project affected persons, and avoiding reservoir impacts in Laos (which constrained the full reservoir elevation to 164 meters above sea level)

Conclusions

20. These questions are discussed further in Annex 3, which concludes as follows:

- Vietnam's power sector development strategy of developing its indigenous conventional hydro resources, and its domestic gas and coal resources, before turning to other imported fuels, is robust to a wide range of uncertainty in input assumptions, including assumptions on load forecast and international energy prices.

- Alternatives to this hydro strategy would be extremely costly, with significant increases in GHG emissions.

- These general findings are also confirmed by the Strategic Environmental Assessment of the Hydro Development Plan prepared for MoIT by the Stockholm Environmental Institute.

- The power development plan already envisages a substantial program of small hydro and renewable energy development (supported by the World Bank's Renewable Energy Development Project), as well as efforts to promote supply and demand side energy efficiency (an Energy Efficiency Law is close to enactment). Not building *any* additional peaking power generation projects is not a reasonable alternative, given Vietnam's likely progress in economic development and poverty alleviation.

- Among the remaining hydro projects, Trung Son has favorable economics and relatively modest environmental impacts that are expected to be fully mitigated by the World Bank's safeguards policies.

- The Trung Son investment decision is robust with respect to load forecast uncertainty and international oil price uncertainty.

1.4 Outline of the report

21. Section 2 reviews the hydrology and the estimates of power generation, and presents a comparison of the PECC4 estimates with the results of our own reservoir operation simulations.

22. Section 3 examines possible changes to the long term hydrology resulting from climate change: no comprehensive studies of the impact of climate change on the hydrology of the Southeast Asia region are available, so the best that can be done is to hypothesise a worst case scenario extrapolated from studies elsewhere.

23. Carbon accounting assumptions are presented in Section 4. There are two main issues. First, the extent to which the carbon benefits of Trung Son (the avoided GHG emission from coal and natural gas combustion) are

offset by incremental emissions of methane and CO_2 from the reservoir. Secondly, whether GHG emission calculations should be limited to those associated with combustion, or whether they should include life-cycle effects (i.e., include the GHG emissions associated with fossil fuel extraction, transport, and construction).

24. The economic and financial analysis of the project is presented in Section 5, including a sensitivity analysis to the main input assumptions (construction cost overruns, world oil prices, and higher rates of sedimentation than expected).

25. Section 6 presents the risk assessment. This consists of a Monte Carlo simulation analysis to derive the probability distribution of economic returns. Finally, Section 7 presents the distributional analysis, which reconciles the economic and financial flows, and identifies the costs and benefits to the affected parties.

2 Review of Hydrology and Power Generation

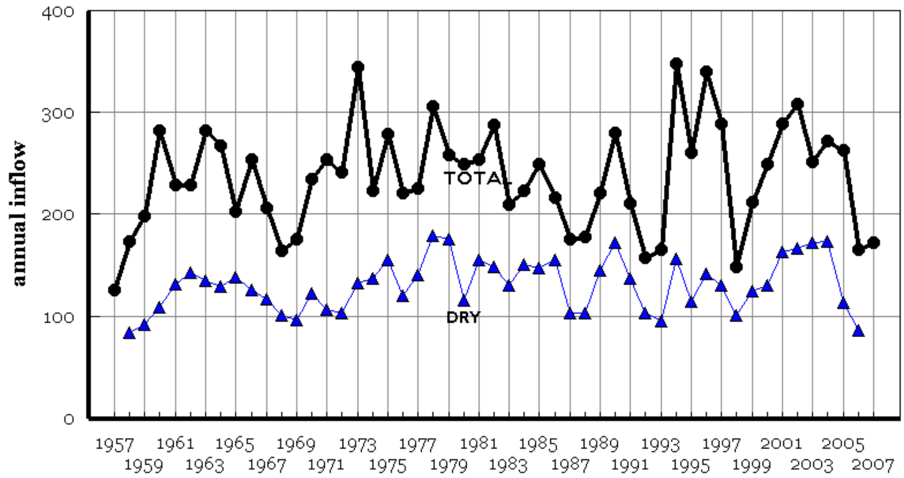
26. The hydrology data have been reviewed by an independent technical expert.[12] The focus of that review was the soundness of the methodology to forecast the flow series, and the review of the assumptions for predicting the maximum floods and the related dam safety issues.

27. However what is of most interest to the economic and financial analysis is the statistical properties of the inflow series as they affect the hydrology risks of the project. This was outside the scope of the technical hydrology review, and is therefore presented below. We take as given the latest daily inflow series, that run from June 1957 to June 2007.[13]

2.1 Inflow series and their variability

28. Figure 2.1 shows the average annual inflows (as well as the average dry season inflow). The overall average inflow is 235 cubic metres per second (cumecs).

Figure 2.1: Annual and dry season inflows [cumecs]



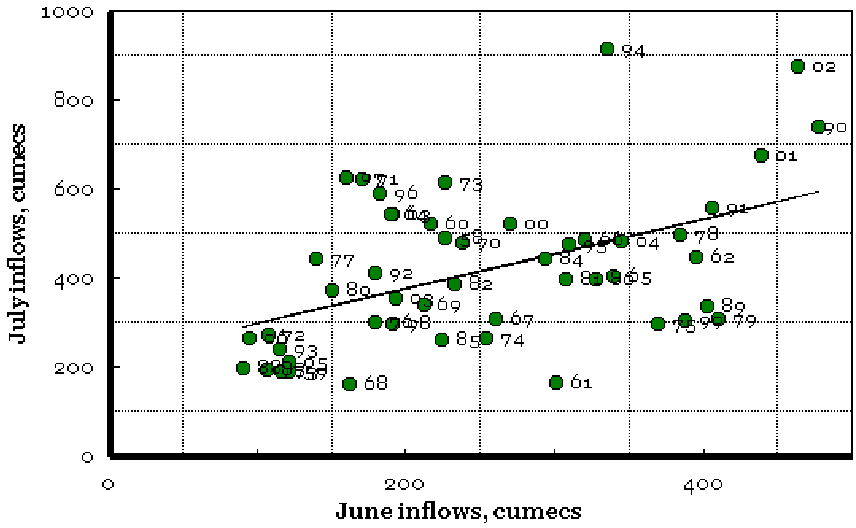
[12] Ngo Thi Hoa, *Reviewing Results on Hydrological Report*, June 2007.

[13] Provided to us as the EXCEL file ZHO.XLS, dated 30 November 2008.

29. There is no evidence of any persistent linear trend in either the total inflow or the dry season inflow; the estimated linear model has a slightly upward trend (though it is not statistically significant).[14]

30. However, there is strong evidence of serial correlation in monthly inflows. For example, Figure 2.2 shows July inflows as a function of June inflows: the statistically significant relationship[15] means that higher than average June inflows makes more likely higher than average inflows in July.

Figure 2.2: July inflows as a function of June inflows



31. Table 2.1 shows the complete set of estimated parameters for the lag-1 autoregressive models of the form

$$Q[month\ t] = \alpha + \beta\, Q[month\ t\text{-}1] + u_t$$

Where α and β are parameters to be estimated (by ordinary least squares, OLS), and u_t is a random variable of zero mean. All the equations are statistically significant.

Table 2.1: Regression coefficients in the lag-1 autoregressive model

		α		β				
Qfeb	=	8.4	+	0.770 Qjan	(t=	20.63	),R^2=	0.901
Qmar	=	14.1	+	0.751 Qfeb	(t=	8.19	),R^2=	0.588
Qapril	=	25.5	+	0.753 Qmar	(t=	5.15	),R^2=	0.361
Qmay	=	15.6	+	1.247 Qapril	(t=	6.12	),R^2=	0.444

[14] The estimated OLS model has an R^2 of 0.002.

[15] In this report, “statistically significant” in OLS regression means rejection of the null hypothesis at 5%. For annual series with 50 observations, the t-value needs to exceed about 1.6 at 5%, or 2. 5 at 1%.

		α		β				
Qjune	=	135.3	+	0.941 Qmay	(t=	3.00	),R^2=	0.161
Qjuly	=	219.0	+	0.779 Qjune	(t=	3.75	),R^2=	0.230
Qaug	=	389.7	+	0.440 Qjuly	(t=	2.79	),R^2=	0.142
Qsept	=	252.4	+	0.488 Qaug	(t=	3.78	),R^2=	0.233
Qoct	=	202.0	+	0.179 Qsept	(t=	2.76	),R^2=	0.139
Qnov	=	76.4	+	0.352 Qoct	(t=	6.46	),R^2=	0.471
Qdec	=	47.7	+	0.436 Qnov	(t=	10.80	),R^2=	0.713

32. How to use the apparent statistical patterns to derive an optimal operating rule goes beyond the scope of this report. However, the evidence suggests there is considerable scope for improving the simple operating rule proposed by PECC4, particularly if a real-time information for watershed and upstream flow gauging can be integrated into probabilistic decision rules. There is also some evidence of serial correlation of *annual* flows (and hence generation), which affects the risk assessment of successive annual cashflows being lower than average.

2.2 Reservoir operation

33. PECC4's estimates of annual power generation in the historical record are based on application of a reservoir operations simulation model: the annual tables are included in Annex 33 of PECC4's Hydropower-Energy Economy report. However, we have not sighted any detailed description of this model.[16]

34. Given the potential difficulties of integrating PECC4's reservoir simulation model into the economic and financial models that incorporate risk assessment tools, as needed for this report, it was decided that the most credible verification of the PECC4 estimates would be to run the same input hydrology in a different model, and independently replicate PECC4's results. As noted below, PECC4's *power generation* results prove to match those of this report with only small differences, providing additional comfort for the economic returns presented in Section 5.

35. The critical assumption in a reservoir simulation is the rule curve, that governs the reservoir level (or storage) over time. Unlike some of the other hydro projects in the EVN system, Trung Son provides no seasonal carryover storage, and its active storage of 112 million cubic metres (MCM) represents only a few days of storage at average inflow. Trung Son operates as a daily peaking project during the dry season, and in effect as a

[16] From the appearance of the output tables it seems likely that this was originally programmed for a mainframe computer.

baseload plant for much of the wet season when all four units may run 24 hours a day for extended periods.

36. During the dry season, the objective is to maintain the reservoir level as high as possible to maximise the hydraulic head. This level should be reached each day at the beginning of the peak hours; the subsequent peak hour discharge is constrained in such a way that the next day's inflow during the off-peak hours should again restore the level to the maximum level. If one discharges too much on any one day, then next day's maximum level will be lower than optimal; if one discharges too little, then one may have to spill the next day – obviously undesirable. However, during most of the dry season the inflows are fairly even and predictable, with few if any unexpected storms, so operation fairly close to the theoretical optimum (given the available inflows) is generally achievable.

37. The problem with many reservoir simulation models is that they assume perfect hindsight. Table 2.2 shows an extract from the PECC4 calculations for January 1961. The average flows start at 110.6 cumecs at the beginning of the month, and slowly decline to 92.8 cumecs by the end of the month.

Table 2.2: Excerpt from the PECC4 daily operations simulation table

Date	Qs (m3/s)	Qtbin (m3/s)	Qhaluu (m3/s)	N (MW)	Htt (m)	Zho (h)	Wtb (106m3	Zhi (m)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
1/1/1961	110.6	110.0	110.0	68.3	70.6	160.0	348.5	89.3
1/2/1961	110.6	110.0	110.0	68.3	70.6	160.0	348.5	89.3
1/3/1961	110.6	110.0	110.0	68.3	70.6	160.0	348.5	89.3
1/4/1961	110.6	110.0	110.0	68.3	70.6	160.0	348.5	89.3
1/5/1961	110.6	110.0	110.0	68.3	70.6	160.0	348.5	89.3
1/6/1961	110.6	110.0	110.0	68.3	70.6	160.0	348.5	89.3
1/7/1961	108.5	107.9	107.9	67.0	70.6	160.0	348.5	89.3
1/8/1961	107.0	106.4	106.4	66.1	70.6	160.0	348.5	89.3
1/9/1961	107.0	106.4	106.4	66.1	70.6	160.0	348.5	89.3
1/10/1961	107.0	106.4	106.4	66.1	70.6	160.0	348.5	89.3
1/11/1961	103.5	102.9	102.9	64.0	70.7	160.0	348.5	89.3
1/12/1961	101.3	100.7	100.7	62.6	70.7	160.0	348.5	89.3
1/13/1961	99.9	99.3	99.3	61.8	70.7	160.0	348.5	89.3
1/14/1961	99.9	99.3	99.3	61.8	70.7	160.0	348.5	89.3
1/15/1961	99.9	99.3	99.3	61.8	70.7	160.0	348.5	89.3
1/16/1961	99.9	99.3	99.3	61.8	70.7	160.0	348.5	89.3
1/17/1961	99.9	99.3	99.3	61.8	70.7	160.0	348.5	89.3
1/18/1961	96.3	95.7	95.7	59.6	70.7	160.0	348.5	89.2
1/19/1961	94.2	93.6	93.6	58.3	70.8	160.0	348.5	89.2
1/20/1961	94.2	93.6	93.6	58.3	70.8	160.0	348.5	89.2
1/21/1961	94.2	93.6	93.6	58.3	70.8	160.0	348.5	89.2
1/22/1961	94.2	93.6	93.6	58.3	70.8	160.0	348.5	89.2
1/23/1961	94.2	93.6	93.6	58.3	70.8	160.0	348.5	89.2
1/24/1961	94.2	93.6	93.6	58.3	70.8	160.0	348.5	89.2
1/25/1961	94.2	93.6	93.6	58.3	70.8	160.0	348.5	89.2
1/26/1961	92.8	92.2	92.2	57.4	70.8	160.0	348.5	89.2
1/27/1961	92.8	92.2	92.2	57.4	70.8	160.0	348.5	89.2
1/28/1961	92.8	92.2	92.2	57.4	70.8	160.0	348.5	89.2

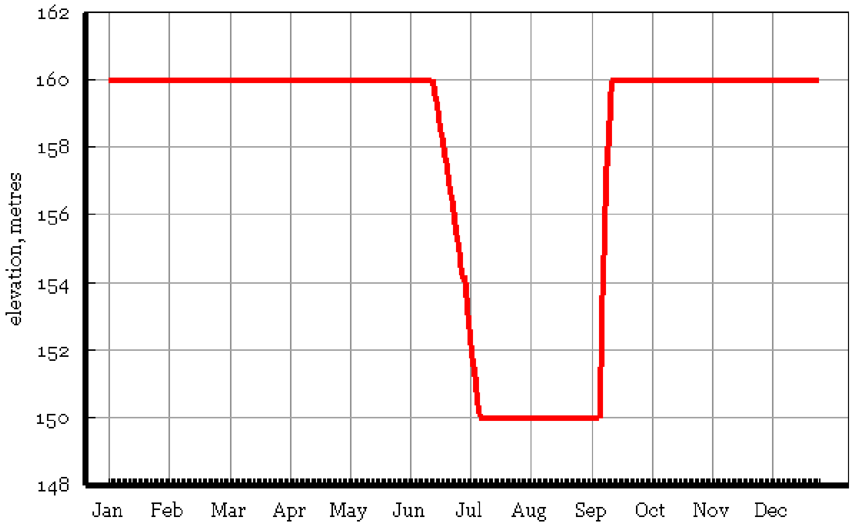
Date	Qs (m3/s)	Qtbin (m3/s)	Qhaluu (m3/s)	N (MW)	Htt (m)	Zho (h)	Wtb (106m3	Zhi (m)
1/29/1961	92.8	92.2	92.2	57.4	70.8	160.0	348.5	89.2
1/30/1961	92.8	92.2	92.2	57.4	70.8	160.0	348.5	89.2
1/31/1961	92.8	92.2	92.2	57.4	70.8	160.0	348.5	89.2

Source: PECC4, file ZHO.XLS

38. Inspection of this table suggests that turbine flows have been adjusted each day to *exactly* equal inflow minus losses, and Qturbine reduces every day. The volume in storage is always exactly at the maximum (Zho=160).

39. Things are more complicated during the wet season. In order to provide for flood control storage, the reservoir is operated at the lower level of 150m. The reservoir must be drawn down from 160m to 150m by July 15, and can be refilled starting September 15. The target operating curve thus appears as in Figure 2.3.

Figure 2.3: The rule curve



40. Given the magnitude of monsoon season storms, and the modest flood storage, some spill is inevitable. The flood control storage of 112.13 MCM is sufficient to absorb an average daily flow of 1,299 cumecs – yet the maximum daily discharge can be several times this value. Only in 10 of the 50 years is the maximum daily discharge less than this value (Figure 2.4). But even in these years, if there are several days of flows between the maximum discharge capacity of all four turbines (504 cumecs) and 1,299 cumecs, spill will result – as shown in Figure 2.5, only in the very dry year of 2006 does the simulation model show zero spill.

Figure 2.4: Maximum daily discharge observed in each year

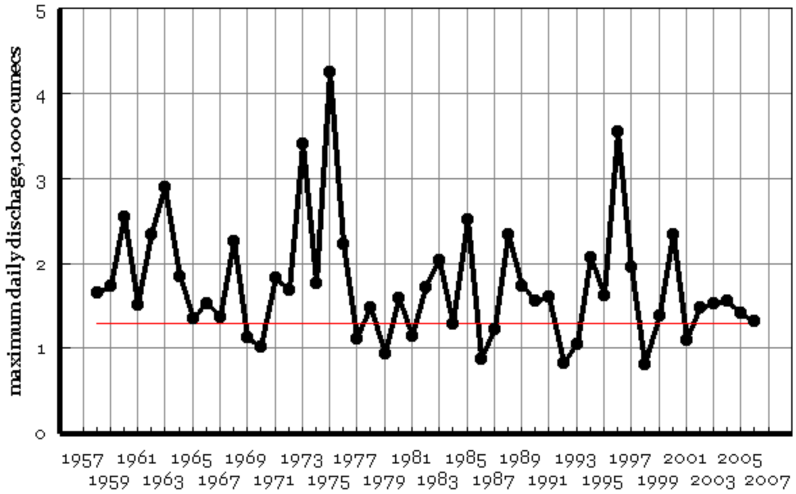
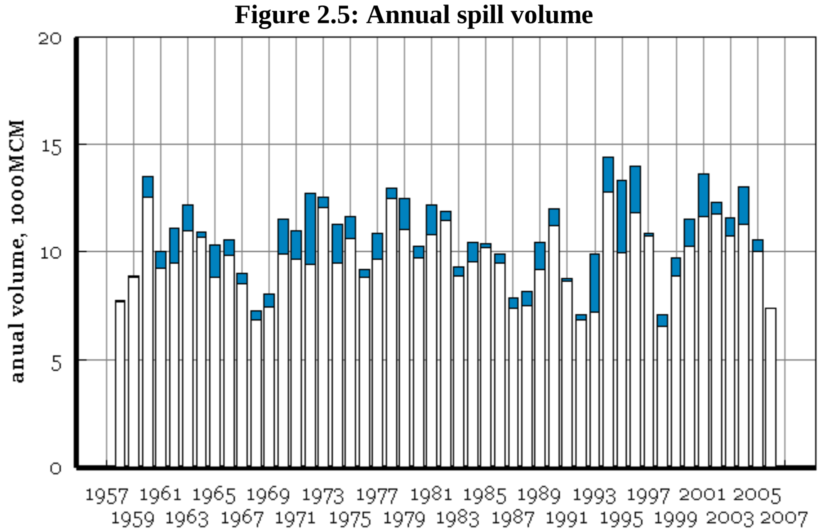


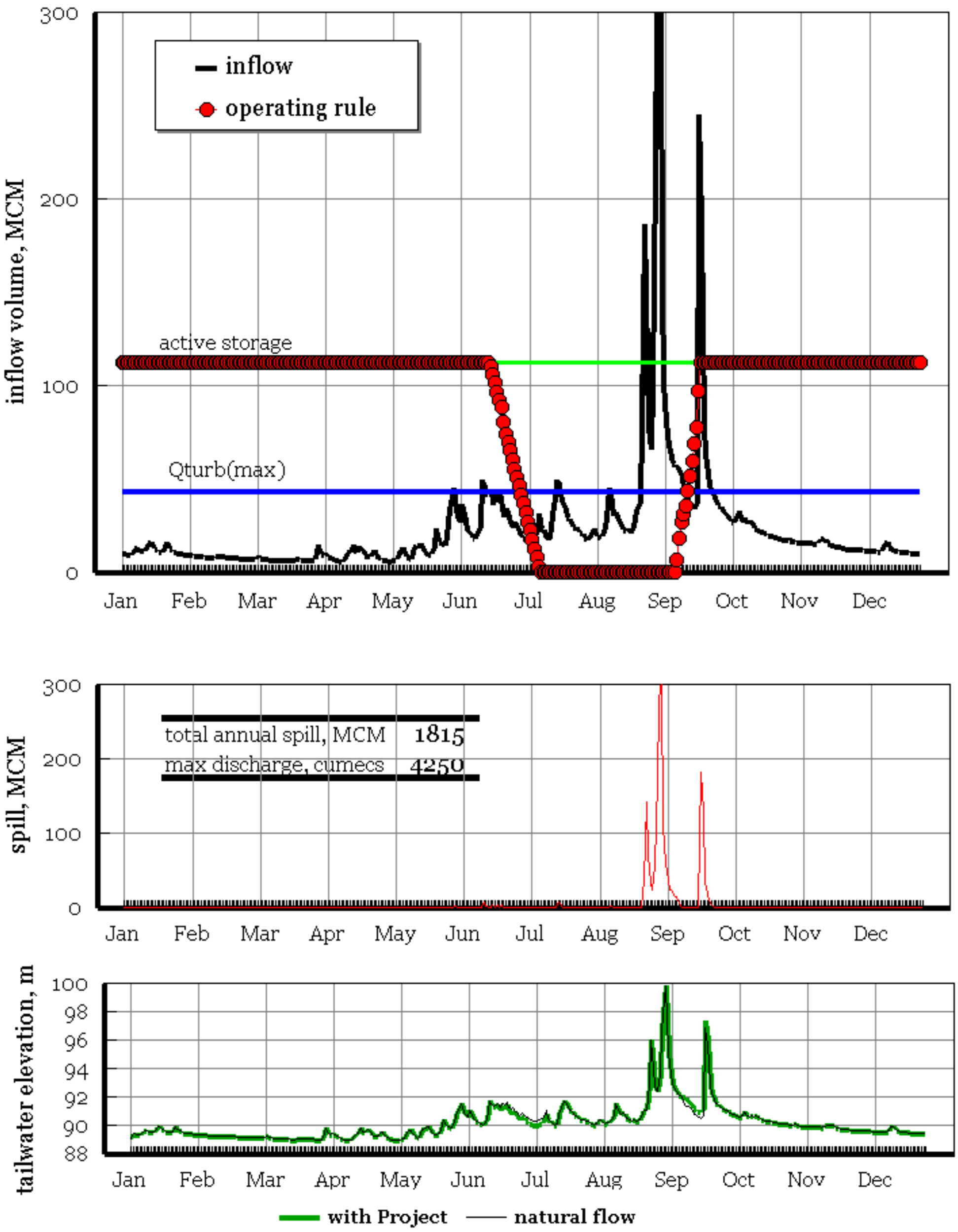
Figure 2.5: Annual spill volume



41. The results of our reservoir simulation model for 1975 are shown in Figure 2.6. This is the year that records the highest rate of daily discharge in the inflow series, namely 4,250 cumecs (or 367 MCM) on September 5 (which followed an average discharge of 3,662 cumecs on the previous day).[17] The top panel shows the inflow volumes and the volume in active storage which mimics the rule curve of Figure 2.3. In July and August the maximum (target) elevation is 150 metres, so the entire active storage is available for flood discharges. In the latter part of September this is relaxed, and the reservoir can be operated at its FRL until the following June.

[17] However, this is not the wettest year in the record (as measured by total annual discharge), which is 1994.

Figure 2.6: Reservoir operations, 1975

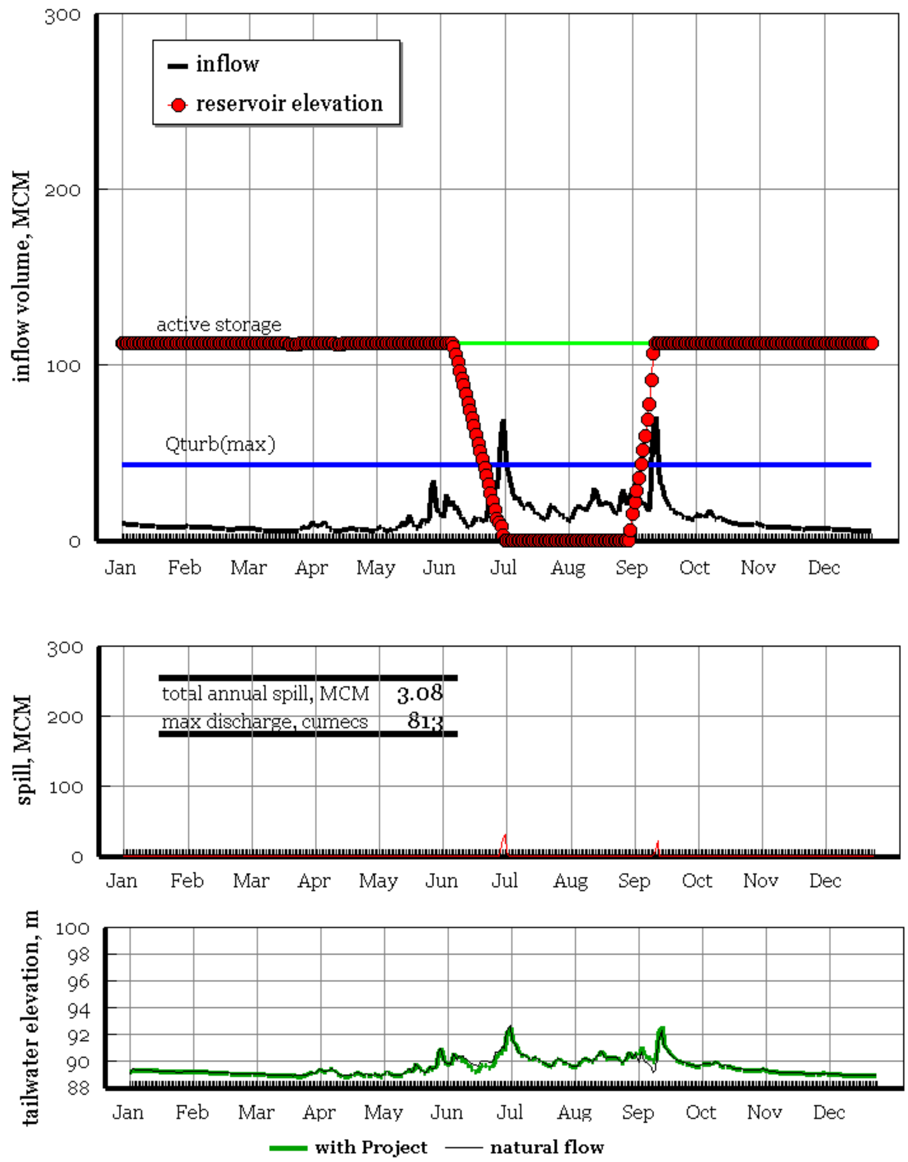


42. The middle panel shows the daily volumes spilled – whose timing correspond to the peak inflows shown in the top panel. Finally, the bottom panel shows the tail water elevation – which rises from a normal level of 88-90 metres during the dry season to 100 metres during the peak spill days.[18] During such peak flow conditions the power generation head reduces (because the net head is given by the difference between the reservoir and tail water levels, adjusted for penstock friction losses)

[18] The relationship between the flow and tail water elevation is described by the socalled *tail water curve:* the greater the discharge, the higher the tail water elevation.

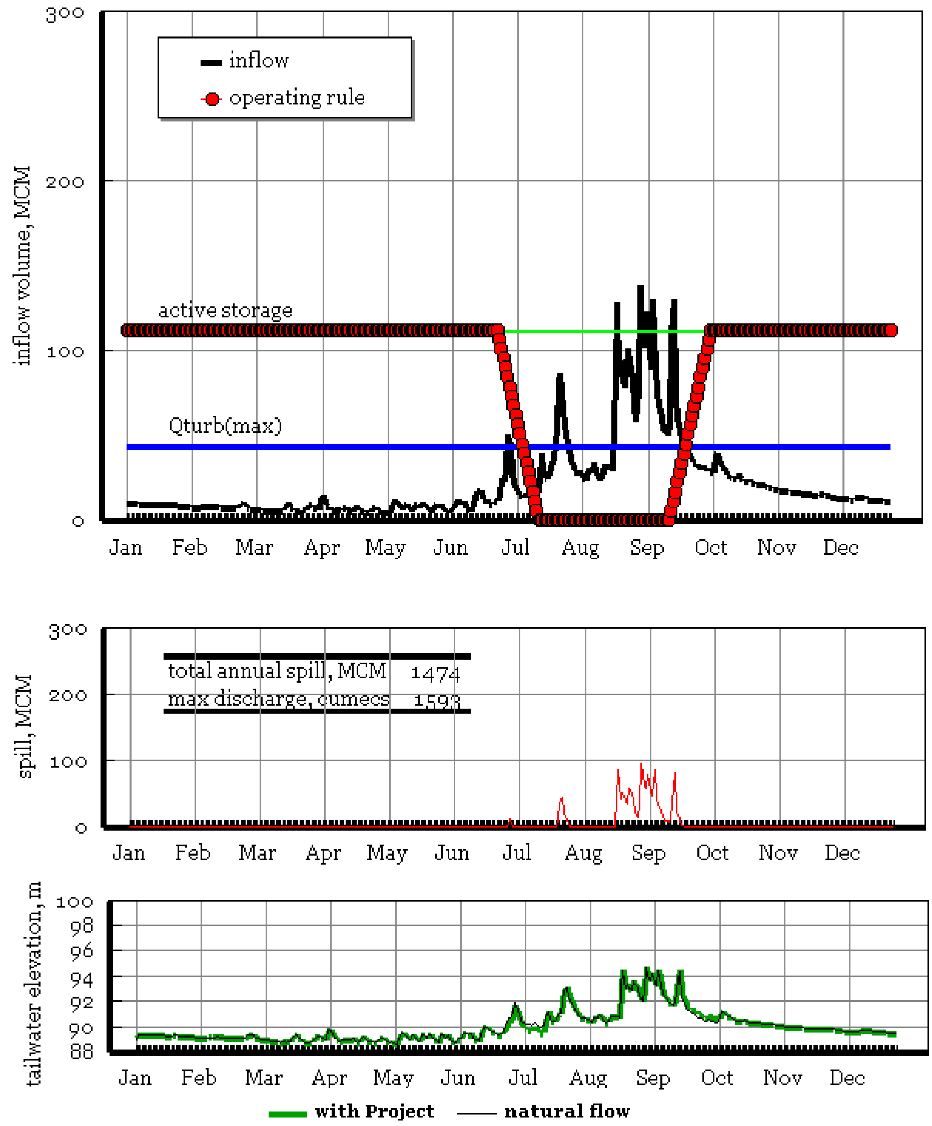
43. In contrast, 1998 was the driest year on record (Figure 2.7), with an average inflow of just 147 cumecs (compared to the average of 235 cumecs). The spill is minimal, and occurred on just three days of the year.

Figure 2.7: 1998 Reservoir operation



44. Finally, Figure 2.8 shows the simulation for a more typical year (1980) with a mean annual flow of 249 cumecs.

Figure 2.8: Reservoir operation in 1980



2.3 Environmental flows

45. In the dry season, the project is to be operated for daily peaking. The inflow is not sufficient to run all units at full power all day, but by storing the inflow in the off-peak hours, full turbine discharge can be achieved during the evening peak. However, during the hours when inflows are being stored, no water would be discharged downstream, causing potential disruption to the downstream environment. This is mitigated by maintaining some minimal "environmental" flow throughout the day, which if insufficient to run at least one turbine at its minimal discharge, must be released through a low-level conduit. This is discussed in the PECC4 December 2008 report, which states as follows:

> During the reservoir water impounding period between May to June, the Ma river downstream of Trung Son will have no water. So, to maintain the environment flow for this river section, a certain flow discharge will be released to downstream.[19]

46. Based on an assessment of the natural dry season flows, and the flow contributions from tributaries immediately downstream of Trung Son, the minimum flow requirement to maintain the downstream ecology is determined to be 15 cumecs. However it is unclear why the "impounding period" runs only from May to June – in fact the concern would be throughout the dry period.

47. It appears that the minimum discharge to run one of the four turbines is 63 cumecs. Therefore, if the required environmental flow is 15 cumecs, there will be a significant reduction in power generation only during such times as the inflow is *less* than 63 cumecs (and when the low level outlet must be used). Table 2.3 shows the number of days in each dry season that this condition occurs: in many years this condition does not occur at all.

Table 2.3: Days of inflow less than 63 cumecs.

	Jan	Feb	March	April	May	June	total
1958	**31**	**23**	**31**	**30**	**26**	**5**	**146**
1959	0	12	8	7	9	0	36
1960	0	4	22	30	18	0	74
1961	0	0	4	0	13	0	17
1962	0	0	5	0	0	0	5
1963	0	0	0	8	1	0	9
1964	0	0	0	0	0	0	0
1965	0	0	7	9	7	0	23
1966	0	0	6	6	20	0	32
1967	0	0	9	9	4	0	22
1968	0	0	0	0	0	0	0
1969	0	22	31	15	17	1	86
1970	0	6	25	18	0	0	49
1971	0	0	21	12	0	0	33
1972	0	0	0	5	10	0	15
1973	0	0	0	4	0	0	4
1974	0	0	0	0	0	0	0
1975	0	0	0	0	0	0	0
1976	0	0	0	0	0	0	0
1977	0	0	0	0	0	0	0
1978	0	0	0	0	0	0	0
1979	0	0	0	0	0	0	0
1980	0	0	9	6	6	3	24
1981	0	0	7	4	4	0	15
1982	0	0	1	0	4	0	5
1983	0	0	0	0	0	0	0
1984	0	0	0	1	0	0	1
1985	0	0	0	0	0	0	0
1986	0	0	0	0	0	0	0
1987	0	0	0	0	4	0	4

[19] "PECC4, *Operation Model of Reservoir*, December 2008, p39.

	Jan	Feb	March	April	May	June	total
1988	0	0	0	2	0	2	4
1989	0	0	0	12	0	0	12
1990	0	0	0	0	0	0	0
1991	0	0	0	0	0	0	0
1992	0	0	0	7	7	0	14
1993	0	0	3	14	0	0	17
1994	0	0	3	1	3	0	7
1995	0	0	18	26	19	0	63
1996	0	0	7	11	1	0	19
1997	0	0	0	0	0	4	4
1998	0	0	0	0	0	0	0
1999	15	28	31	21	11	0	106
2000	0	0	0	0	0	0	0
2001	0	0	0	1	2	0	3
2002	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0
2005	0	0	1	2	21	1	25
2006	0	0	4	8	5	0	17

48. In some years, such as 2006 (Figure 2.9), in the latter months of the dry period (April and May) early rains provide days of higher inflows, so on the low flow days the reservoir could easily be drawn down slightly to provide a constant turbine flow of 63 cumecs, given a high probability of higher inflows some days later.

Figure 2.9: 2006 dry season inflows

Q_e = required environmental flow, 15 cumecs
Q_{min}= minimum turbine flow, 63 cumecs

49. However, in very lean dry seasons, such as 1999, inflows of less than 63 cumecs can persist for several months (Figure 2.10), so the turbine could not run at this discharge level for 24h/day, and discharge from the low-level outlet is unavoidable.

Figure 2.10: 1999 Dry season inflows

50. Under such conditions the question is whether it is better to release 15 cumecs from the low level outlet for longer periods (i.e. without running through the turbines), but then run the turbines at full discharge for some (limited) number of the peak hours. While this would reduce the *total* energy generated, depending upon the relative financial and economic benefits of peak v. off-peak energy this might still be cost-effective. [20]

51. Another constraint concerns the maximum rate of change of downstream flow. A very rapid increase from 63 cumecs to the full turbine discharge of 503 cumecs may be technically possible, but would result in sudden increases in the tail water *elevation* in addition to the sudden increase in the discharge *volume*. At 63 cumecs, the tail water elevation is 88.9 meters, rising to 92 metres at 503 cumecs.

52. The rate of change in downstream flow should not be greater than that which occurs without the project, which PECC4 estimates to a maximum average rate of change of 40 cumecs per hour. This implies a 11-12 hour period to increase from 63 to 504 cumecs – as illustrated in Table 2.4 and Figure 2.11, which further limits the proportion of total energy that can be generated during the peak hours.

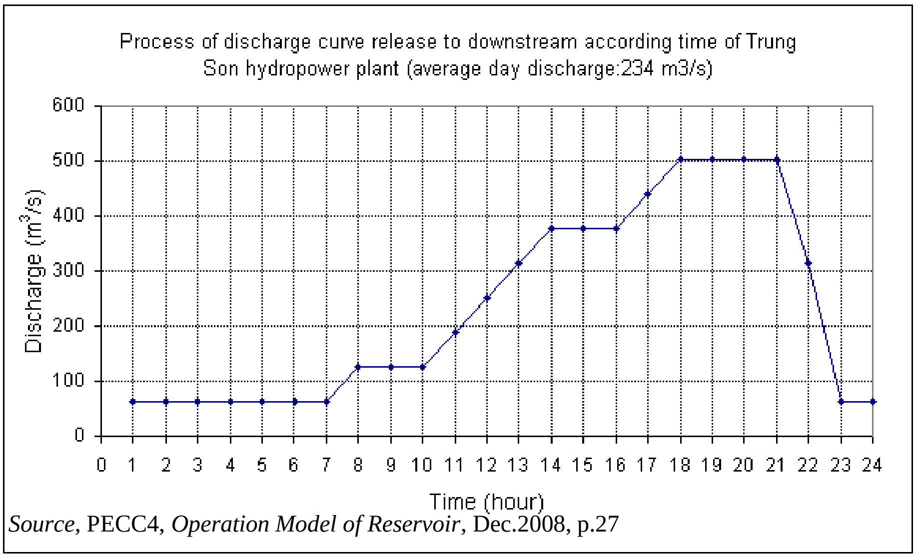
53. As we note below in the sensitivity analysis of Section 5, any loss of firm capacity due to these ramping constraints has little impact on the economic returns: even if the firm capacity were reduced to zero, the economic returns are significantly greater than the hurdle rate.

[20] Certainly in the case of a small hydro project that benefits from the avoided cost tariff (which provides a premium for generation during dry season peak hours), one would meet the environmental flow requirement during the off-peak hours from the low level conduit, and generate only during peak hours.

Table 2.4: Hourly discharge patterns

	discharge(m^3/s)					
hour	unit 1	unit 2	unit 3	unit 4	total	increase
1	63				63	
2	63				63	
3	63				63	
4	63				63	
5	63				63	
6	63				63	
7	63				63	
8	126				126	63
9	126				126	
10	126				126	
11	126	63			189	63
12	126	63	63		252	63
13	126	126	63		315	63
14	126	126	126		378	63
15	126	126	126		378	
16	126	126	126		378	
17	126	126	126	63	441	63
18	126	126	126	126	504	63
19	126	126	126	126	504	
20	126	126	126	126	504	
21	126	126	126	126	504	
22	126	63	63	63	315	-189
23	63				63	-252
24	63				63	
Average	102	55	50	26	234	

Figure 2.11: Daily discharge curve



Source, PECC4, *Operation Model of Reservoir*, Dec.2008, p.27

54. If indeed the 63 cumec minimum flow can be maintained at all times, then there would be no need for the low level outlet, because the outlet is also not required for flushing out sediments.[21]

2.4 Energy generation estimates

55. PECC4's detailed economic analysis report (of March 2008) reports an average annual generation of 1,055 GWh. As best as we can tell, this figure is derived on the basis of the monthly reservoir simulations included in Appendix 33, a series that extends only to 2003. In PECC4's December 2008 report, which states clearly that the power generation estimates are based on *daily* flow series, the calculation of average energy is given as 1006.7 GWh. However, this series runs to June 2007: and since the additional years 2002-2007 include the two very dry years 2006 and 2007, the average would in any event be slightly lower.

56. We have verified the figure by running the daily flow series through our own reservoir simulation model. Because our reservoir operations model is attached to the economic and financial analysis models, this is run on a calendar year basis (rather than the hydrology year basis of the PECC4 models).[22] Our estimate of the annual average energy is 994 GWh.

57. In addition to the daily simulations being intrinsically more reliable than the monthly simulations, there are some other possible reasons for small differences in energy estimates, notably in the assumption for turbine efficiency: if the PECC4 simulations used the detailed design performance curves for the turbines, their estimates will be better than the average efficiency used by us).[23]

58. However this may be, given the various uncertainties of any modelling procedure our results are in close agreement: the PECC4 power generation calculations can thus be said to have been independently verified (based on the historical hydrology provided). The economic analysis uses PECC4's latest revised estimate of 1,019 GWh as the annual average generation.

[21] This is discussed further in Section 5.3: even worst case rates of sediment accumulation could easily be accommodated by the dead storage.

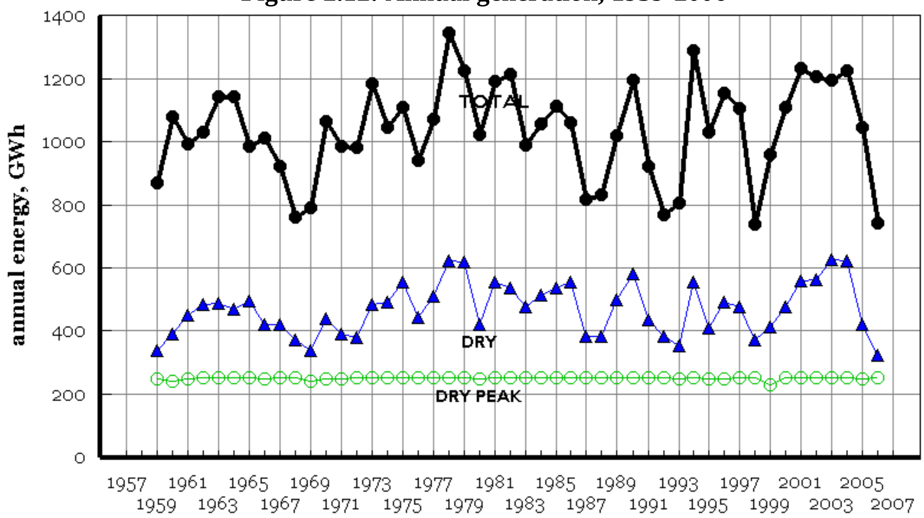
[22] For this reason, the individual annual estimates show considerable differences – but these even out in the 50-year average.

[23] We have not yet been able to locate the design curves in any of the reports (in English) sighted by us. In at least one of the PECC4 reports (the December 2008 study, *Operation Model of the Reservoir*), it is stated that " the simulation of hydro-energy operation of reservoir according efficiency of powerhouse was selected at average of 0.88 " -

Annual variations

59. Substantial variations in annual generation will arise, as one might expect given the large variations in inflows. In the presentation of Figure 2.12, we use the new definition of wet season proposed by ERAV for the renewable energy avoided cost tariff, namely a wet season that runs from July-Oct (rather than the previous MoIT definition that ran just for the three months from July-September).[24]

Figure 2.12: Annual generation, 1959-2006

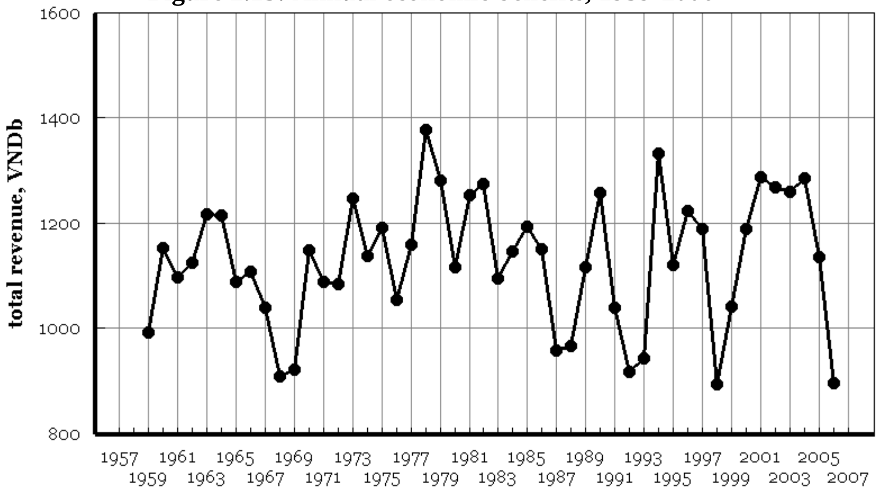


60. The constancy of the generation during the evening peak hours of the dry season is a consequence of the ability to operate the project as a daily peaking project. Since there are no flood control restrictions during the dry season, and since dry season flows are fairly predictable on a day-ahead basis, as noted above the reservoir can be drawn down at the end of each daily peak period to such a level that one reaches full reservoir elevation at the start of the following day's peak period – during the dry season there is little risk of a sudden storm then requiring a spill.

61. The corresponding variations in revenue are substantial. While the average is VND 1,105 billion, in a typical wet year the revenue increases to VND 1,300 billion, but in a dry year can fall to only VND 900 billion. This has potentially important implications for the ability to meet debt service obligations.

[24] ERAV, *Avoided Cost Tariff Methodology Report*, May 2008.

Figure 2.13: Annual economic benefits, 1959-2006



62. A related question of interest to lenders is whether, given a low inflow and low revenue in year t, can anything be said about the probability of year t+1 also being a below average year (the worst case), or whether it is more likely that year t+1 will be above average (the best case from the lender's perspective). To answer the question the model to be estimated is

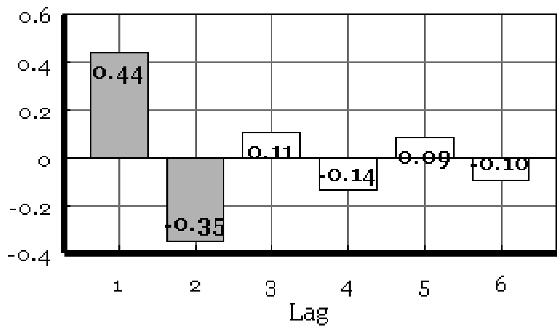
$$R_t = \alpha + \sum_j \beta_j R_j + u_t ;\ j=1,..N$$

Where α, β are coefficients to be estimated by OLS, N is the number of lags considered (6 in this case), and U_t is a random term.

63. The estimated coefficients are shown in Figure 2.14, but only the first two lags are statistically significant. The two lag model has the form

$$R_t = 967.5 + 0.41R_t - 0.35R_{t\text{-}1}$$

Figure 2.14: Coefficients in the autoregressive model



64. This confirms the patterns one can discern in Figure 2.13: dry years and wet years do seem to run in groups of 2 - of the 8 driest years in the record, 6 occur in groups of 2.

3 The Potential Impact of Climate Change on Hydrology

65. In the last few years the question of the potential impact of climate change on hydropower production has received growing attention, particularly in the high alpine regions (central Europe, Nepal)[25] and in regions where hydro projects are directly fed by glacier and their glacial lakes (High Andes, Himalayas, European Alps).[26] Indeed in Peru during the past few years, glacier-fed hydro projects have seen *increased* flows and generation as the glaciers have retreated.

66. However, none of the Trung Son watershed is snow-fed, and therefore lack the storage benefit of snow cover that boosts spring runoff. The general conclusion of studies for such tropical and sub-tropical watersheds is that climate change will lead to an intensification of storms, and hence intensification of runoff (higher flood flows) in the wet season, and less precipitation in the dry season; and that the impact on hydropower generation therefore depends critically on the available storage.[27] Pure run-of-river projects will be most affected, and while daily peaking projects may still be able to deliver some firm capacity during peak hours, the number of peak output hours will fall. For new projects, the economic rates of return fall by a few percentage points.

67. This general conclusion was confirmed in a detailed World Bank study of medium sized (<300 MW) hydro projects in Peru;[28] in the worst case for non-glacial fed projects, dry season energy was expected to fall by

[25] See, e.g., B. Schaefli, B. Hingray and A. Musy, *Climate Change and Hydropower Production in the Swiss Alps: Quantification of Potential Impacts and Related Modelling Uncertainties*, Hydrology and Earth System Sciences, 11 (3) 1191-1205, 2007; S.Agrawala, V. Raksakulthai, M. van Aalst, P. Larsen, J. Smith and J. Reynolds, *Development and Climate Change in Nepal: Water Resources and Hydropower*, OECD, 2003.

[26] A World Bank-ESMAP study to assess the impacts of climate change on mountain hydrology in the Andes is underway, with results expected later in 2009 (*Assessment of Impacts of Climate Change on Mountain Hydrology: Development of a Methodology through a Case Study of Peru*" Progress Report 1, March 2009).

[27] M. Moirza, *Climate Change, Water and Implications for Hydropower,* Hydropower and Dams, 1, 2008.

[28] World Bank: *Peru: Overcoming Barriers to Hydropower*, ESMAP Draft report, March 2009.

15-20%. In the case of the typical hydro project, total annual energy generation was estimated to fall from 775 to 705 GWh, and the ERR (in a daily peaking project) from 14.7 to 13.7%. [29]

68. Few studies cover Southeast Asia. In the Mekong River Basin, most of the attention regarding the impacts of climate change is on the impacts of sea level rise in the Mekong delta[30]; only one systematic study of the impact of climate change on the basin's hydropower projects (underway at the University of Washington) could be found.

69. A 2007 World Bank study assessed global climate change impacts on three hydro projects in Asia, which included the Thac Mo extension project in Vietnam.[31] The methodology used in this study is entirely statistical, and includes no simulations of project operation, so the findings need to be treated with some caution: nevertheless, the analysis suggested only a very small negative impact - though as noted by its author, the study looked at only one climate change scenario. Nevertheless, the findings do have some relevance to Trung Son, and are summarised in Annex 2.

70. There are other potential consequences of climate change, particularly if monsoon storms intensify. In the Kulekani watershed in Nepal, a catastrophic flood in July 1993 caused a massive amount of sediment to enter the Kulekani hydro project reservoir.[32] Watershed deforestation may have played a significant role in that case, and underscores the continuing importance of watershed management.

The MoNRE climate change scenarios

71. In June 2009 the Ministry of Natural Resources and Environment published an assessment of the impact of climate change on Vietnam, which included scenarios for changes in rainfall (as well as temperature and sea level rise).[33] The report notes a number of observed trends that may have potential significance for the Trung Son hydrology:

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[29] *Ibid*, Table 3.4.

[30] In November 2008 the US Interior Department announced a project with Can Tho University to study the impact of climate change on low-lying delta regions worldwide (including the Mekong, Nile, Yangtze and Volga deltas.)

[31] Atsuchi Iimi, *Estimating Global Climate Change Impacts on Hydropower Projects: Applications in India, Sri Lanka and Vietnam*, World Bank Sustainable Development Network, Policy Research Working Paper 4344, September 2007. The other projects examined were the Upper Kotmale project in Sri Lanka, and the Vishnugad Pipalkoti project in India (all three are projects funded by JBIC).

[32] Moirza, *op.cit*., p.88

[33] Ministry of Natural Resources and Environment, *Climate Change and Sea Level Rise Scenarios for Vietnam*, Hanoi, June 2009.

- A higher frequency and intensification of typhoons affecting Vietnam
- Annual rainfall has decreased in the northern areas, and increased in the southern areas. On average in the period 1958-2007, rainfall decreased by 2%
- Fewer cold fronts, but more intense (such as the prolonged 2008 cold surge in Northern Vietnam)

72. Based on the IPCC scenarios, and a detailed modelling study using the MAGICC/SCENGENB model, MoNRE prepared a series of scenarios for the different regions of Vietnam. Most of the Trung Son watershed falls into the North-western region, for which Table 3.1 shows the expected changes in rainfall.

Table 3.1: Rainfall changes in the Northwest, as % over the decade 1980-1999.

	2020	2030	2040	2050	2060	2070	2080	2090	2100
high scenario	***1.6***	***2.1***	***2.8***	***3.7***	***4.5***	***5.6***	***6.8***	***8.0***	***9.3***
Dec-Feb	1.2	1.7	2.2	2.9	3.6	4.4	5.3	6.2	7.2
Mar-May	-1.2	-1.6	-2.1	-2.8	-3.5	-4.3	-5.2	-6.1	-7.1
June-Aug	2.5	3.5	4.6	5.9	7.5	9.3	11.0	12.2	15.1
Sept-Nov	0.5	0.6	0.8	1.1	1.4	1.7	2.1	2.4	2.8
medium scenario	***1.4***	***2.1***	***3.0***	***3.8***	***4.6***	***5.4***	***6.1***	***6.7***	***7.4***
Dec-Feb	1.1	1.6	2.3	2.9	3.6	4.2	4.8	5.2	5.6
Mar-May	-1.1	-1.6	-2.3	-2.9	-3.5	-4.1	-4.6	-5.2	-5.6
June-Aug	2.4	3.5	4.8	6.2	7.6	8.8	10	11	11.9
Sept-Nov	0.4	0.6	0.9	1.1	1.4	1.6	1.8	2.0	2.2
low scenario	***1.4***	***2.1***	***3.0***	***3.6***	***4.1***	***4.5***	***4.7***	***4.8***	***4.8***
Dec-Feb	1.1	1.6	2.3	2.9	3.2	3.5	3.6	3.7	3.7
Mar-May-1.1	-1.1	-1.6	-2.3	-2.8	-3.0	-3.4	-3.6	-3.7	-3.7
June-Aug	2.4	3.5	4.8	5.9	6.7	7.3	7.6	7.8	7.8
Sept-Nov	0.4	0.6	0.9	1.1	1.2	1.3	1.4	1.4	1.4

Source: MoNRE

73. From the perspective of assessing the impact of these predicted changes on the economic returns, one may note that changes in the first 15-20 years have a much greater impact on ERR ands NPV than 30-50 years hence. Moreover, even though under all scenarios, total rainfall is predicted to increase by about 3% by 2040 (highlighted in Table 3.1), this may be of less significant than the seasonal changes. If the increased rainfall in the wet season (June-November) occurs in more intense storms resulting in greater probability of spill, there will be little extra energy generation. However, less inflow in the dry season (March-May) translates more directly into lower generation, since given prudent reservoir operation, in these months the reservoir is never in spill condition. Consequently in the sensitivity analysis of Section 5, we assume for sake of being conservative the worst case of reduced dry season inflows, but no additional wet season generation.

74. The report notes that

> *the medium scenario is recommended for ministries, sectors and provinces use as an initial basis for climate change and seas level rise impact assessments and in the development of actions plans to respond to climate change.*[34]

75. However, over the first 25 years of Trung Son operation (i.e. by 2040) there is little difference across the scenarios: dry season rainfall decreases by between 2.1 and 2.3%. Moreover, given the normal range of hydrological variation, with annual generation varying from 800 to 1,200 GWh (see Figure 2.13), a long term decrease of average dry season inflows of a few percent will have very little impact on the economic returns – a hypothesis confirmed by the sensitivity analysis of Section 5: Figure 5.3 shows that total generation would have to fall by 50% before the ERR decreases from its baseline estimate of 18.9% to the 10% hurdle rate. In short, even under MoNRE's worst case, it is extremely unlikely that climate change induced rainfall pattern changes will have any significant impact on Trung Son.

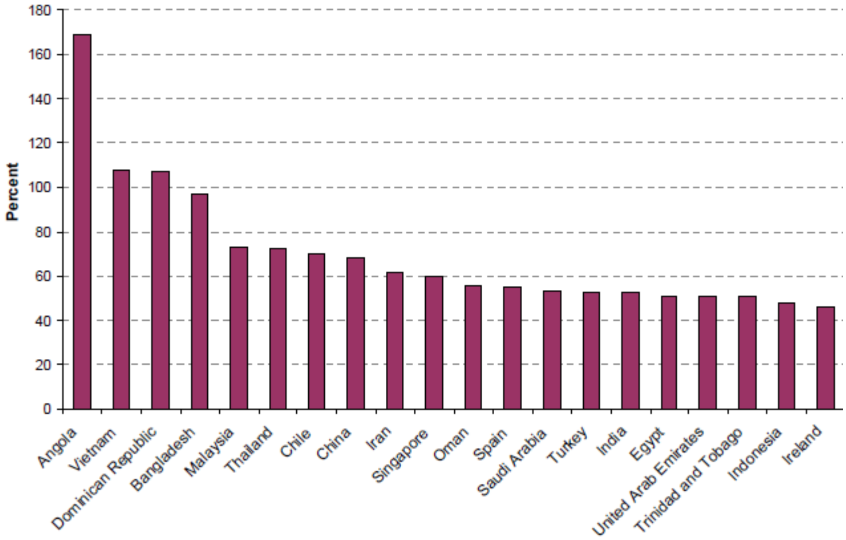
[34] MoNRE, *op.cit.*, p.16

4 Carbon Accounting

4.1 GHG emissions

76. In the past decade, Vietnam's GHG emissions have risen sharply, and a recent World Bank comparative study shows Vietnam to have the second highest GHG emission growth rate among countries in the decade 1994-2004 (Figure 4.1) – albeit from a very low base.

Figure 4.1: Growth in GHG emissions between 1994 and 2004



Source: R. Bacon and S. Bhattacharya, *Growth and CO_2 emissions: how do different countries fare?*, World Bank Environmental Department Papers, 113, November 2007.

77. The growth rate may be high, but in absolute terms emissions are still low: Vietnam's emissions, and emissions per capita, are the lowest among its main regional neighbours, as is its per capita GDP (Table 4.1). Only in terms of emissions per unit of GDP is it comparable to Malaysia, Thailand and Indonesia.

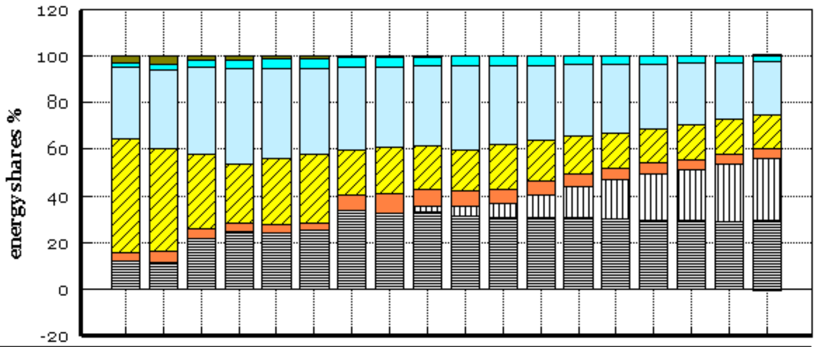
78. In 2008, domestic coal (anthracite) accounted for 12% of energy generation, compared to 44% from gas. But as shown in Figure 4.2, this is expected to change significantly over the next years, as coal comes to dominate power generation: by 2020, coal will account for 50% of generation, and gas only 16%; by 2025, 60% will be coal.

Table 4.1: Comparative indicators for Vietnam's GHG emissions

	2004 emissions, million metric tons	2004 per capita GDP at market exchange rate	tons/ $million GDP at market exchange rate	%CO_2 from fossil fuel combustion	emissions per capita (tons/ person)
Vietnam	**57**	**496**	**1,394**	**52**	**0.69**
China	4,707	1311	2,745	59.5	3.60
Philippines	75	1,094	836	30.4	0.92
Indonesia	308	894	1,564	9.3	1.4
Malaysia	154	4,296	1,437	12.5	6.17
Thailand	219	2,356	1,457	48.8	3.43
USA	5,912	36,234	552	86.8	20.01

Source: Bacon & Bhattacharya, *op.cit.*

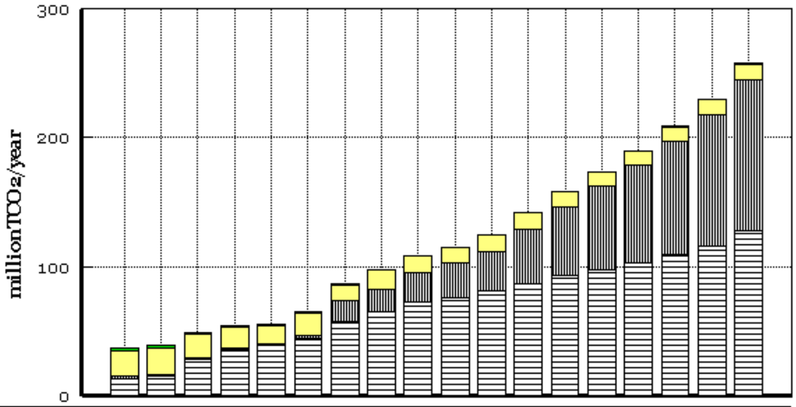
Figure 4.2: Power sector generation mix (share energy generation)



		2009		2011		2013		2015		2017		2019		2021		2023		2025
coalSteam	12	12	22	25	24	25	34	33	33	31	31	31	31	30	30	29	29	29
coalSteamI	0	0	0	0	0	0	0	0	2	4	6	10	14	17	19	22	25	27
CFB	4	5	4	4	3	3	7	8	7	7	6	6	5	5	5	4	4	4
CCGT	49	44	32	25	28	30	19	20	19	18	19	18	16	15	15	15	15	15
hydro	31	34	37	41	39	36	36	35	34	36	34	32	30	30	28	26	24	23
hydroPS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-0	-0	-0	-0
SHP/RE	1	3	3	4	4	4	4	4	4	4	4	4	4	4	3	3	3	3
CCCT_LNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
imports	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
oil,CT, other	3	4	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0

79. Thus power sector GHG emissions will rise rapidly over the next 20 years, as shown in Figure 4.3 - from 49 million tons of GHG emissions in 2008 to some 250 million tons in 2025.

Figure 4.3: Power sector GHG emissions



		2009		2011		2013		2015		2017		2019		2021		2023		2025
domestic coal	14	16	29	37	40	44	58	65	73	76	81	87	93	98	103	109	116	128
imported coal	1	1	1	1	1	2	16	18	22	27	31	42	53	64	75	88	102	117
gas	20	21	18	16	14	17	13	14	13	12	13	12	11	11	11	11	12	12
oil	2	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0

4.2 Combustion emission factors

80. Table 4.2 shows the IPCC default emission factors for the main fossil fuels. Vietnam's domestic coal is largely anthracite, which has the highest GHG emission factor per unit of energy among fossil fuels.

Table 4.2: CO_2 emission factors from combustion

	Kg CO_2/TJ	Kg/mmBTU
anthracite	98,300	93.21
bituminous	94,600	89.70
sub-bituminous	96,100	91.12
lignite	101,000	95.77
diesel	74,100	70.26
fuel oil	77,400	73.39
gas	56,100	53.20

Source: IPCC, default values

UNFCCC defaults

81. One option for the calculation of the GHG emissions impact of Trung Son would be to use the UNFCCC emission factors for approved CDM projects: the Song Muc small hydro project has an approved emission factor of 0.6KgCO_2/kWh.[35]

[35] UNFCCC CDM-SSC-PDD, Song Muc Hydro Project, 2005

82. However, this value has been derived on the basis of the simplified methodology available to small projects under 15 MW. [36] This is based on the average of the so-called "build margin", and the "operating margin" - calculations of average emissions of the power system per kWh generated, and for which the default emission factors of Table 4.2 can be used. The merit of this calculation is its simplicity; the ease of its validation; and the likelihood that it is conservative. But the question is whether it is *too* conservative?

83. During the wet season, when Trung Son project runs more or less 24 hours per day, it will displace coal generation in the North, with the result that the most *inefficient* coal unit should be taken off-line for this period. There is no reason to suppose that the dispatch centre would back down an "average" unit, as implied by the simplified methodology. Indeed there are significant variations in heat rate among the older coal units, as shown in Table 4.3.[37]

Table 4.3: Heat rates at the existing coal-fired units in Northern Vietnam

	2003	2004	2005	2006	average heat rate, Kcal/kWh	efficiency
Pha Lai 1	2578	2202	2458	2937	3146.6	27.3%
Pha Lai 2	3202	3529	4300	4315	2351.6	36.6%
Uong Bi	730	641	670	756	3747.5	22.9%
Ninh Binh	680	633	690	793	4155.3	20.7%
average						26.9%

Source: IoE

84. Similar variations in heat rates also apply to gas-fired units, as shown in Table 4.4, with a range of efficiencies from 40.8% to 50.7%.

85. Most of the gas generation in Vietnam is in combined cycle units, not open cycle units. Even the worst performing CCGT has an efficiency of 40.8%, substantially above the 33% efficiency used in the Song Muc Calculations (which appears to be based on open cycle gas turbines, which account for only a very small proportion of the total gas generation).[38] And, as in the case of the coal units, there is no reason to suppose that the gas

[36] UNFCCC, Methodological Tool, Version 01.1, Tool to calculate the emission factor for an electricity system

[37] Current IoE assumptions are that the Uong Bi and Ninh Binh units will be retired in 2015. However, the efficiency of Pha Lai 1 is significantly lower than that of Pha Lai 2.

[38] This illustrates some of the problems that Vietnam's small hydro projects have encountered in obtaining CDM registration: the proposition that a simple calculation methodology is more reliable and conservative than a more sophisticated assessment of the impact on dispatch is clearly in some doubt.

plant that would be displaced is the "average" project; rather, it will be the plant with the *worst* heat rate (Ba Ria).

Table 4.4: Heat rates at existing gas-fired CCGTs in Southern Vietnam

	2003	2004	2005	2006	average heat rate, BTU/kWh	efficiency
Ba Ria	2138	2163	2204	2022	8367	40.8%
Phu My 21	3477	4398	3640	6112	74557	45.8%
Phu My 1	6397	6518	7171	6417	6878	49.6%
Phu My 4	-	1628	3013	3211	7307	46.7%
Phu My 3	167	4154	4441	4110	6730	50.7%
Phu My 22	-	210	3720	4856	6883	49.6%

Source: IoE

86. These problems have been discussed by UNFCCC in the revised methodology document for grid-connected renewable energy[39], which describes the procedures for a more reliable calculation based on plant dispatch information.

4.3 GHG emissions from reservoirs

87. GHG emissions from hydro reservoirs remain a controversial topic. In 2000 the World Commission on Dams noted three points that are still valid:[40]

- Hydropower cannot, a priori, be automatically assumed to emit less greenhouse gas than the thermal alternatives. Net emissions should be established on a case by case basis.
- The flooded biomass alone does not explain the observed gas emissions. Carbon is flowing into the reservoir from the entire basin upstream, and other development and resource management activities in the basin can increase or decrease future carbon inputs to the reservoir.
- As natural habitats also emit greenhouse gases it is the *net* change due to impoundment that should be used for assessment, and not the gross emissions from the reservoir.

88. Absent any Asian data on methane and CO_2 fluxes from reservoirs[41], the best that can therefore be done is to calculate an upper

[39] UNFCCC *Consolidated Baseline Methodology for Grid-connected Electricity Generation from Renewable Sources,* 19 May 2006

[40] World Commission in Dams, *Final Report on Dams and Development A New Framework for Decision-making to the Framework Convention on Climate Change*, November 2000.

bound on *gross* GHG emissions based on the same Brazilian data upon which UNFCCC has based its own proposal for default calculations.

Power density

89. The so-called power density, measured as watts/m^2 of reservoir area has come into increasing us as a proxy for the GHG efficiency of a hydro project. UNFCCC has issued a draft guideline for the CDM eligibility of hydro projects that uses this measure:[42]

- Projects with power densities (installed power generation capacity divided by the flooded surface area) less than or equal to 4 W/m^2 are excluded;
- Projects with power densities greater than 4 W/m^2 but less than or equal to 10 W/m^2 can be eligible, but with an emission penalty of 90 g CO_2eq/kWh;
- Projects with power densities greater than 10 W/m^2 are eligible without penalty.

90. UNFCCC notes that in a database of 245 hydro plants in operation in the world today with at least 30 MW of installed capacity, it finds the average power density is 2.95 W/m^2.

91. With a flooded area at full reservoir level of 13.1 km^2, and a power output of 260 MW, the power density of Trung Son calculates to 19.8 Watts/m^2. This compares favourably with the range of power densities for Brazilian projects for which detailed methane and CO_2 flux survey data is available (and which are the basis for the thresholds proposed by UNFCCC) (Table 4.5).

[41] The plan for vegetation clearance has detailed estimates of the standing biomass, but it seems that the area to be completely cleared is limited to some 50 ha with 4,700-5,000 tons of flooded biomass to be collected and cleaned (47-50 ha). This is based on what must be removed to assure that the level of dissolved oxygen will be similar to present levels: the remaining biomass is estimated at 40 tons/ha (or 52,400 tons). PECC4, *Reservoir Vegetation Cover Removal Plan*.

[42] UNFCCC CDM Methodology Panel, Nineteenth Meeting Report, Annex 10, *Draft Thresholds and Criteria for the Eligibility of Hydroelectric Reservoirs as CDM Projects*.

Table 4.5: Power densities for Brazilian hydro projects and Trung Son

project	province	installed capacity	reservoir area	power density
		MW	Km^2	W/m^2
Xingo	Caatinge	3,000	60	50
Trung Son	**Vietnam**	**260**	**13.13**	**19.8**
Segredo	Mata Atlantica	1,260	82	15.47
Itaipu	Mata Atlantica	12,000	1,549	8.13
Miranda	Cerrado	390	50.6	7,72
Tucuri	Amazonica	4,240	2,430	1.74
Serra da Mesa	Cerrado	1,275	1,784	0.71
Barra Bonita	Mata Atlantica	141	312	0.45
Samuel	Amazonica	216	559	0.39
Tres Marias	Cerrado	396	1,040	0.38

Source: Marco Aurélio dos Santos *et al.*, *Variability of Greenhouse Gas Fluxes from Hydropower Reservoirs in Brazil*, UNESCO Workshop on Freshwater reservoirs and GHG emissions, Paris, November 2006.

92. Table 4.6 shows power densities for hydro projects in Vietnam, including power densities for the small hydro projects to be financed under the World Bank's renewable Energy Development Project (REDP).

Table 4.6: Power densities for Vietnamese Hydro projects

project	installed capacity	reservoir area	power density
	MW	km^2	W/m^2
large hydro			
Trung Son	260	13.13	19.8
Song Bung 4	156	15.8	9.9
small hydro			
Sung Vui	18	3.2 ha	563
Nam Tang	6.5	0.3 ha	2,167
Dak Me	4	2.1 ha	190
Can Ho	4.2	0.7 ha	600
Ha Tay	9	64 ha	14

Comparison of reservoir GHG emissions with avoided thermal emissions

93. To calculate the avoided GHG emissions from thermal generation we make the conservative assumption that during the dry season, Trung Son displaces gas CCGT in the South (which is true only to the extent that the 500kV transmission line has excess capacity). In the wet season we assume that Trung Son displaces coal.

94. The marginal gas project is Ba Ria (see Table 4.4), and the marginal coal project is taken as the average of the three worst heat rate plants (Table 4.3). The average daily avoided GHG emissions from thermal generation compute to 6.9 million kg/day (Table 4.7).

Table 4.7: Avoided GHG emissions from fossil fuel combustion.

		wet	dry	total
average GWh		545	449	
days		123	242	
GWh/day		4.43	1.86	
fuel displaced		anthracite	natural gas	
emission factor	Kg/mmBTU	93	53.20	
heat rate	BTU/kWh	14,612	8,367	
emission factor	$KgCO_2$/kWh	1.362	0.445	
million Kg/day		6.0	0.8	6.9

95. The methane and CO_2 emissions from the Trung Son reservoir are calculated in Table 4.8. The fluxes are the median values from the Brazilian surveys [43]

Table 4.8: Methane and CO_2 flux from the Trung Son reservoir

component	units	
methane flux from reservoir		
methane flux	[mg CH_4/day]	80
global warming potential	[ ]	21
CO_2 emissions	[mg CO_2/day/m2]	1,680
reservoir surface area	[km^2]	13.1
CO_2 per day	[kg/day]	22,008
CO_2 flux from reservoir		
CO_2 emissions	[mg CO_2/day/m2]	2,600
reservoir surface area	[km^2]	13.1
CO_2 per day	[kg/day]	34,060
Total CO_2 +CH_4	[kg/day]	56,068
	[tons/year]	20,464
As fraction of avoided thermal emissions	[%]	0.8%

96. This calculation has high uncertainty, and is almost certainly conservative because it ignores the natural fluxes that occur in the absence of the project, and because we assume that the avoided thermal generator in the dry season is gas-CCGT in the South. Given that the upper bound on gross emissions is less than 1%, one can be reasonably confident that the GHG emissions impact of the Trung Son reservoir can be ignored. Indeed, it is of the same order of magnitude of the avoided 500 kV transmission losses associated with the displacement of gas generation in the South, also ignored in this calculation.

97. Under the revised CDM rules, the default emission factor for projects with power densities between 4 and 10W/m^2 is 90 $kgCO_2$/MWh.

[43] *Source:* Marco Aurélio dos Santos *et al.*, *Variability of Greenhouse Gas Fluxes from Hydropower Reservoirs in Brazil*, UNESCO Workshop on Freshwater Reservoirs and GHG emissions, Paris, November 2006.

With annual generation of 1,019 GWh, the corresponding Trung Son CDM default emissions calculate to 91,710 tons CO_2/year, 4 times higher than the detailed calculation of Table 4.8 that shows 20,464 tons/year. Of course, with a power density of 19.8 W/m^2, the Trung Son project would not be subject to the default value: but the comparison does show that GHG emissions from the Trung Son reservoir are not an issue.

4.4 Life cycle emissions

98. Finally, there is the question of whether one need only consider emissions from combustion, or whether one should attempt the quantification of life cycle emissions. The increasing attention to life cycle emissions is largely the consequence of criticism about claims regarding the GHG benefits of nuclear and hydro generation, and the recognition that all technologies, including renewable generation such as wind, have an impact on GHG emissions by virtue of the energy required for the manufacture of equipment, as well as in fuel extraction, transport and decommissioning.

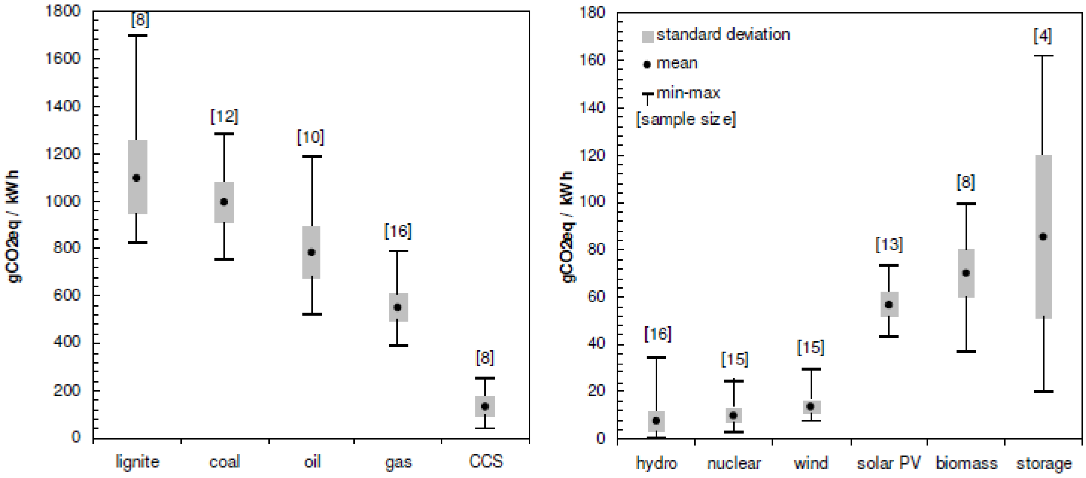
99. There is little doubt that the bulk of GHG emissions associated with thermal generation technologies derive from actual fuel combustion. The necessary calculations are relatively straightforward and uncontroversial, and subject to relatively modest uncertainties. But whether one should account for these indirect impacts as well as the direct impacts of combustion depend upon the answers two further questions:

- how large are these impacts compared to combustion?
- can reliable calculations of indirect impacts be made, and, if so, under what circumstances is the burden of calculation reasonable?

Magnitude of life-cycle emissions

100. Leaving aside the more extreme claims, the consensus of the technical literature appears to be that, *in general*, the life cycle emissions associated with mining, transport, materials inputs, construction and decommissioning represent 5-10% of life-cycle emissions for most fossil fuel technologies. The results of a recent literature review are shown in Figure 4.4, which summarises the life-cycle emissions estimates from some 50 studies: hydro, nuclear and wind all have emissions in the range of 10-40 gmCO_2/kWh, compared to 800-1,300 gmCO_2/kWh for coal.

Figure 4.4: Summary of Life-cycle GHG emissions



Source: D. Weisser, *A Guide to Life-cycle GHG Emissions from Electric Supply Technologies*, Energy (32) 2007, pp. 1543-1559.

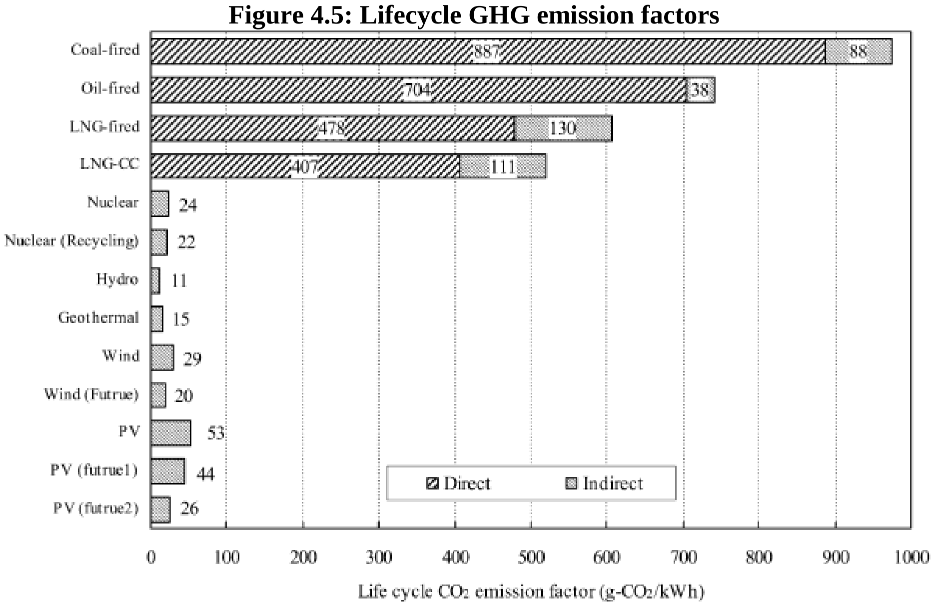
101. Figure 4.5 summarises the results of a typical country-specific study- in this case for Japan,[44] the most interesting finding of which is the high value for non-combustion impacts of LNG. The indirect emission factors for an LNG CCGT (111 gm CO_2/kWh) and 130 gm/kWh for a steam cycle LNG fueled project are the largest for any technology, and significantly higher than for coal projects (88gm CO_2/kWh). Liquefaction is an energy intensive process, but more important is the high CO_2 content of the extracted gas, which is released during processing – 20-30% in the case of Indonesia.[45]

102. For gas-fuelled plants there is the further issue of leakage, which, given a global warming potential of 21, has a disproportionate impact on aggregate GHG emissions: in the Japan study, methane leakage in LNG production was estimated at 9 gm/kWh, with a further 19.4 gm/kWh in LNG transportation.

[44] *Source*: H. Hondo, *Life cycle GHG emission analysis of power generation systems: The Japanese case*, Energy,30 (2005) 2042-2056.

[45] Similarly in In Vietnam, the gas field supplying the O Mon power complex (Block Ba nd 52) is reported to contain 23% inert gas.

Figure 4.5: Lifecycle GHG emission factors



Source: H. Hondo, *Life cycle GHG emission analysis of power generation systems: The Japanese Case*, Energy,30 (2005) 2042-2056.

103. In the case of coal plants, much depends on the technology and efficiency, with ultra-supercritical plants having significantly lower emissions than present subcritical projects (Table 4.9) – though this is mainly a consequence of better efficiency, rather than different life cycle impacts.

Table 4.9: GHG emissions for coal technologies

	steam temperature (^{O}C)	steam pressure (Mpa)	thermal efficiency	life cycle emissions gm CO_2 /kWh
subcritical	540	16.6	37.6%	941
supercritical	560	25	43%	788
ultra-supercritical	630	30	45.3%	716

Source: University of Sydney, *Life Cycle Energy Balance and GHG Emissions of Nuclear Energy in Australia*, Report to the Australian Government, 3 November 2006, Table 6.13

104. Table 4.10 compares the life cycle emissions for coal and hydro in an Australian study: again the hydro estimates do not include any reservoir impacts (but they do include dam *construction*). The results are similar to the Japanese results of Figure 4.5 for hydro (14.9 gm/kWh as compared to 11 gm/kWh in Japan). But for coal, the Japanese results are significantly higher, because they include the transportation over long distances the distant mines (in Australia). For domestic anthracite in Vietnam, distances are also relatively short, though for imported coal the transportation impacts will be much higher.

Table 4.10: GHG emissions for coal and hydro

	supercritical coal mine-mouth		Hydro (run-of-river)	
	$gmCO_2/KWh$	% of total	$gmCO_2/KWh$	% of total
mining	33.0	3.2%		
transport	0.4	0.0%	0.2	1.6%
construction	6.9	0.7%	3.3	22.2%
materials			11.4	76.2%
combustion	995.5	96.1%		
decommissioning	0.3	0.0%		
total	1036.1	100.0%	14.9	100%

Source: University of Sydney, *Life Cycle Energy Balance and GHG Emissions of Nuclear Energy in Australia*, Report to the Australian Government, 3 November 2006, Table 6.13

The reliability of life cycle calculations

105. Life cycle emissions calculations encounter a range of problems:

- Emissions may depend upon highly variable site specific circumstances. For example, in a study of life cycle GHG emissions for wind projects in Brazil and Germany,[46] it was found that the emissions related to steel manufacture depend critically on the proportion of scrap used (high in Germany, low in Brazil), and on the generation mix of electricity used in manufacturing industry (low emissions in hydropower dominated Brazil, high emissions in Brown coal dominated Germany): in some cases – as in this comparative study of Brazil and Germany, these may cancel out, but in others not, leading to large differences in values.

- Process analysis, a bottom-up approach to life cycle calculations, for which the energy requirements of the main production processes and suppliers of inputs are assessed in detail, suffers from what has been described as "unavoidable truncation of the system boundary".[47]

- Input-output analysis avoids this problem. But though it accounts for the energy requirements from upstream inputs and supply chains of infinite order, it suffers from its own shortcomings of allocation and aggregation, and requires much more complex models.[48]

[46] M. Lenzen & U Wachsman, *Wind Energy Converters in Brazil and Germany: An example of Geographic Variability*, Applied Energy, 2004 (77) 119-130.

[47] University of Sydney, *Life Cycle Energy Balance and GHG Emissions of Nuclear Energy in Australia*, report to the Australian Government, 3 November 2006.

[48] Input-output models which describe the transactions among production sectors are rarely designed with the requirements of energy-environmental analysis in mind. For example in the case of nuclear projects, enriched uranium or heavy water may not be well represented by the closest sector available (such as "chemicals").

4.5 Conclusions

106. The following conclusions can be drawn

- The net GHG emissions from the reservoir itself can be ignored. The power density of Trung Son is high, and the calculation of the upper bound based on Brazilian data suggests this emission source is less than 1% of the avoided emissions from thermal generation. In any event they are of the same order of magnitude as the avoided 500 kV transmission losses, also ignored in the calculations, which would offset these emissions.

- The life cycle emissions associated with materials and construction of Trung Son are small, and will be taken as 15 gm CO_2/kWh.

- The calculations of emissions from coal and natural gas combustion can use the IPCC default values for the fuel concerned (Table 4.2), but adjusted for actual efficiency of the assumed marginal plants (rather than the averages as in the CDM calculations for Song Muc).

- The life cycle emissions for coal plants will be taken as 40 gm/kWh for domestic anthracite (based on the Australian study), and 80 gm/kWh for imported coal (based on the Japan study).

- For natural gas plants, the life-cycle emissions will be taken as 70 gm/kWh for pipeline gas to account for the high content of CO_2 in the Chevron gas field for O Mon, but 130 gm/kWh for LNG (to account for the significant energy inputs into liquefaction, as well as the high CO_2 content of Indonesian natural gas).

5 Economic Analysis

5.1 Assumptions for benefits

107. The economic benefits of the project derive largely from the avoided costs of thermal energy generation (coal and gas), and the related avoided environmental costs. The firm capacity of the project also avoids some thermal *capacity*. Other smaller benefits include increased agricultural productivity in the project affected area, and flood control benefits. The assessment of the economic benefits requires the following assumptions.

Avoided generation costs: the avoided variable costs of the displaced coal and gas generation are based on the border prices of coal and gas. In wet summer months, when Trung Son runs 24 hours a day, the project replaces coal generation in the North, assumed to be the least efficient of the existing coal projects, Pha Lai 2.[49] In the dry season, Trung Son displaces, at the margin, gas fired generation in the South: again, in the competitive generation market that will be in operation by the time Trung Son is commissioned, at the margin it is the least efficient existing combined cycle gas turbines (CCGTs) that would be replaced (at Ba Ria). The displaced gas generation is adjusted for the transmission losses in the 500 kV system (taken as 2.5%).

World Oil price: Over the long term, both coal and gas prices are linked to the level of oil price, for which the World Bank's current 2011 estimate of $85/bbl (nominal) is used.[50] When escalated at 3% this results in a (nominal) world oil price of $101.5/bbl in 2017, when generation at Trung Son starts. One may note that other authorities anticipate higher oil prices: for example the 2009 IEA Global Energy Outlook forecasts $100/bbl by 2020 (at *constant 2008* prices); many other forecasts have crude oil rising to over $100/bbl already by the end of 2011.

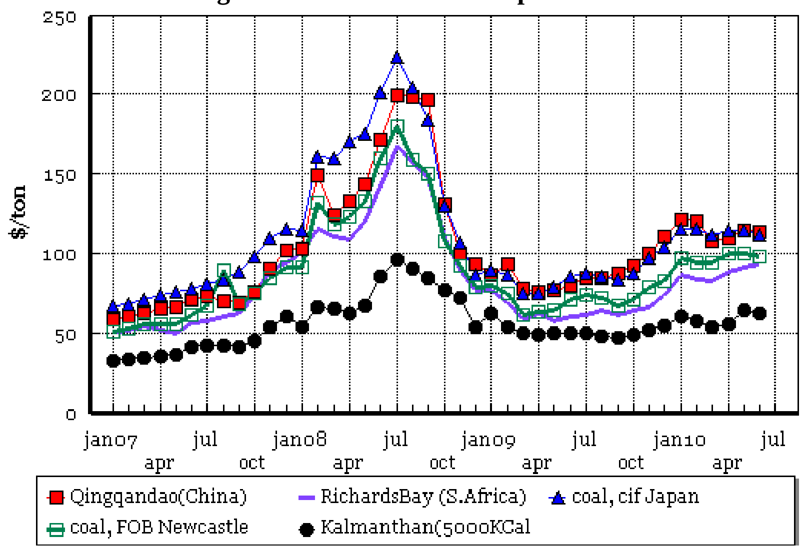
Coal price: For the economic analysis, the relevant value of coal is the border price of imported coal, adjusted for heat content. However, coals of lower heat value trade for less than what can be accounted for

[49] Pha Lai 1 and Uong Bi are currently the most inefficient coal plants, but these are planned to be retired in 2015-2016.

[50] The World Bank definition of average crude oil price (as used in its "Pink Sheets" and commodity price forecasts) is the average of West Texas Intermediate (WTI), Brent, and Dubai, typically 1-2$/bbl higher than the OPEC Reference basket (ORB).

by heat value, as is illustrated by Indonesian coal: in the first quarter of 2009, so-called "Indonesian performance coal" of 5,900 Kcal/kg traded at an average of $69.90/ton fob Kalimanthan, whereas the more abundant Indonesian 5,000 Kcal/kg grade traded at $55.17/ton. If heat value were the sole determinant, then the 5,000 Kcal/kg grade would be priced at $59.15/ton, $4.00/ton more than the actual price. Based on the long term relationship between Australian export coal and the world oil price, when crude oil is $75/bbl, 6,300 Kg/Kcal coal fob Newcastle would be $117/ton, and 5,000 Kg/Kcal Indonesian coal fob Kalimanthan would be $82/ton (again based on historical ratios, see Figure 5.1). When adjusted for transportation, the corresponding *economic* value of the displaced coal at Pha Lai is 88 $/ton, equal to 868VND/kWh (at the current exchange rate of $1=VND19,500).

Figure 5.1: Asia Pacific coal prices



Source: Platt's International Coal Report

Gas price: the gas used at the existing CCGTs that would be displaced by Trung Son benefits from a price significantly below international gas prices. Even the gas pricing formula for the Ca Mau project, namely 1.17 + 0.45 HSFO, where HSFO is the average monthly Singapore spot price for high sulphur fuel oil (as $/mmBTU), provides for a price below gas traded in the region. Gas exported by Malaysia to Singapore is also indexed to the Singapore high sulfur fuel oil (HSFO) price, but at 90% rather than 45%. Therefore we estimate the economic price of natural gas at 1.17 + 0.9HSFO, where the HSFO price can be taken as 80% of the world crude oil price (the impact of alternatives to this assumption are examined in the sensitivity analysis below).

Inflation and exchange rates: OECD inflation is taken at 2.7%. The domestic inflation rate is assumed at 8.4% in 2010, 8% in 2012, 6.10% in 2013 and 5% thereafter, implying a 2.3% per year foreign exchange depreciation rate over the longer term. All the fuel price and avoided cost calculations are done at nominal prices and exchange rates, then deflated to constant 2010 prices for the economic analysis.

Capacity benefit: The baseline capacity benefit is based on the Power Engineering and Consulting JSC No. 4 (PECC4) estimate of firm capacity at 42 MW. Consistent with the proposed Electricity Regulatory Authority of Vietnam (ERAV) practice for calculation of capacity charges in the Vietnam Competitive Generation Market (VCGM), and with practice elsewhere in the region, the cost of capacity is based on a proxy CCGT reflecting international best practice. At the time of writing, absent a specific estimate from ERAV, we use the June 2009 study by the Singapore Regulator as the basis for costs.[51] The resulting estimate of $1,116/kW is somewhat higher than the estimated $ 850-950/MW for Vietnam's most recent CCGT units at Nhon Trach[52] - however the latter appears to be based on gross (ISO) capacity.

Definition of seasons: The new definition adopted by MoIT for the avoided cost tariff is adopted, with a wet season from July to October (rather than the traditional July to September).

Flood control benefits: The annual flood control benefit (at 2009 prices) has been estimated at VND 200 billion (see Annex 1). From this must be subtracted the annual costs of the dyke repair programme (VND 32 billion) and the value of lower power generation (VND 63 billion), for a net annual benefit of VND 105 billion, escalated at the 2010 domestic inflation rate to VND 114 billion.

5.2 Assumptions for Economic Costs

108. The breakdown of capital costs is shown in Table 5.1. Since VAT is refunded to the project sponsor within 3 months of payment, the base cost excludes VAT.

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[51] KEMA, *LRMC of CCGT Generation in Singapore for Technical Parameters used for Setting the Vesting Price for the Period 1 January 2009 to 31 December 2010,* Report to the Singapore Energy Market Authority, 22 June 2009.

[52] The estimate is consistent with that of the comprehensive survey of power plant investment costs prepared for the World Bank in 2008 (URS, *Study of Equipment Prices in the Energy Sector*)

Table 5.1: Economic Investment Cost

base cost	6290.5	VND billion
physical contingencies	315.3	VND billion
total cost	6605.8	VND billion
exchange rate	19,500	VND/$
	338.8	$ million
unit capital cost	1302.9	$/kW

The corresponding outlays over the seven-year construction period are shown in Table 5.2.

Table 5.2: Construction Phasing, Economic Costs

year	2011	2012	2013	2014	2015	2016	2017	Total
phasing	10.2%	15.3%	15.4%	16.0%	16.9%	22.6%	3.6%	10.2%
VNDbillion	673	1,010	1,018	1,054	1,118	1,493	240	673

Other assumptions regarding costs include

- *Escalation of foreign costs*: to calculate the escalation of the cost of imported equipment we use the January 2009 World Bank forecast for the Manufacture Unit Value (MUV) index.[53]
- *O&M costs*: taken as 1.5% of the overnight capital cost.
- *Refurbishments*: VND 735 billion (at 2010 price levels) in each of years 19 and 20 of operation
- *Loss of forest value*: VND 160 billion (based on estimates in the Strategic Environmental Assessment).

5.3 Results

109. Based on the these assumptions, the baseline economic rate of return (ERR) is estimated at 18.9% (real). The NPV is VND 7,038 billion ($361 million) (Table 5.3). The levelised economic cost is 963 VND/kWh (4.9 UScents/kWh).

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53 This index is generally accepted as a proxy for the price of developing country imports of manufactures in U.S. dollar terms. The index is a weighted average of export prices of manufactured goods for the G-5 economies (the United States, Japan, Germany, France, and the United Kingdom). Weights are the relative share in G-5 exports of manufactured goods to developing countries in a base year (currently 1995), with values: U.S. (32.2%), Japan (35.6%), Germany (17.4%), France (8.2) and United Kingdom (6.6%).

Table 5.3: Baseline Economic Returns

			NPV	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
									1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
[1]	**power benefits**	**Real**																					
[2]	energy benefits	VNDb	10984						2	1222	1535	1580	1627	1675	1725	1776	1829	1884	1941	2000	2061	2123	2188
[3]	capacity benefits	VNDb	793						144	142	141	139	138	136	135	134	132	130	129	127	126	124	123
[4]	***other benefits/costs***																						
[5]	loss of forest value	VNDb	-105				-80	-80															
[6]	flood control benefits	VNDb	691						114	114	114	114	114	114	114	114	114	114	114	114	114	114	114
[7]	total benefits	VNDb	12364	0	0	0	-80	-80	259	1478	1789	1833	1878	1925	1973	2023	2075	2128	2184	2241	2300	2362	2425
[8]		**Real**																					
[9]	**Economic costs**	[%]		10.2%	15.3%	15.4%	16.0%	16.9%	22.6%	3.6%													
[10]	Investment costs	VNDb	-4592	-673	-1010	-1018	-1054	-1118	-1493	-240													
[11]	fuelcosts	VNDb	0						0	0	0	0	0	0	0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
[12]	Fixed O&M costs	VNDb	-592						-82	-99	-99	-99	-99	-99	-99	-99	-99	-99	-99	-99	-99	-99	-99
[13]	Variable O&Mcosts	VNDb	0						0	0	0	0	0	0	0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
[14]	Major maintenance	VNDb	-142						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[15]	total costs	VNDb	-5326	-673	-1010	-1018	-1054	-1118	-1575	-339	-99	-99	-99	-99	-99	-99	-99	-99	-99	-99	-99	-99	-99
[16]	Net economic flows	VNDb	7038	-673	-1010	-1018	-1134	-1199	-1316	1139	1690	1734	1779	1826	1874	1924	1976	2029	2085	2142	2201	2263	2326
[17]	ERR	[ ]	18.9%																				
	NPV	$USm	361																				
	levelised economic cost		963.1	VND/kWh																			
			4.9	UScents/kWh																			

Note: all calculations are for an assumed 40-year lifetime – 15 years shown here for sake of legibility

Table 5.4: Economic Returns including avoided social cost of GHG emissions

			NPV	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
									1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
[1]	***avoided generation***																						
[2]	coal	GWh							0	401	489	489	489	489	489	489	489	489	489	489	489	489	489
[3]	gas	GWh							1	424	517	517	517	517	517	517	517	517	517	517	517	517	517
[4]	LNG	GWh							0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[5]	***avoided GHG***																						
[6]	coal	million kg							0	396	483	483	483	483	483	483	483	483	483	483	483	483	483
[7]	gas	million kg							1	273	333	333	333	333	333	333	333	333	333	333	333	333	333
[8]	LNG	million kg							0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[9]	lifecycle-adjustments	million kg		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[10]	total	million Kg							1	669	816	816	816	816	816	816	816	816	816	816	816	816	816
[11]		million tons							0.00	0.67	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82
[12]																							
[13]	carbon price	$/ton		30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
[14]		mVND/ton							0.71	0.73	0.75	0.77	0.79	0.81	0.82	0.83	0.85	0.86	0.87	0.88	0.90	0.91	0.92
[15]	avoided cost of GHG	VNDb	3855						0	489	611	626	642	657	670	680	690	700	710	721	731	742	753
[16]	real	VNDb	1769						0	329	392	382	373	364	355	346	338	330	322	314	306	299	291
[17]	economic flows	VNDb	7038	-673	-1010	-1018	-1134	-1199	-1316	1139	1690	1734	1779	1826	1874	1924	1976	2029	2085	2142	2201	2263	2326
[18]	net economic flows	VNDb	8807	-673	-1010	-1018	-1134	-1199	-1315	1468	2082	2116	2152	2190	2229	2271	2314	2359	2406	2456	2507	2561	2617
[19]	ERR	[ ]	**21.0%**																				
[20]	lifetime avoided carbon	mtonsCO2	31.7																				

Note: all calculations are for an assumed 40-year lifetime – 15 years shown here for sake of legibility

110. The economic returns are higher than those estimated by PECC4, which estimated a baseline ERR of 12.24%. The difference is largely attributable to the estimate of benefits: PECC4 assumes an economic value of dry season energy at VND 720/kWh, and 400 VND/kWh for wet season energy. The PECC4 estimate also excludes flood control benefits and loss of forest value. On the other hand, PECC4 used 0.5% of capital costs for the annual O&M, which appears unrealistically low.

111. When the avoided cost of GHG is added to the analysis, the ERR increases to 21.1% (Table 5.4) This calculation uses the actual emission factors of the avoided coal and CCGT projects that would be displaced by the efficient merit order dispatch likely in the competitive generation market: these are somewhat higher than the factors used in the simplified methodology for CDM purposes as shown in Table 5.5.

Table 5.5: Emission Factor Calculations

	IPCCdefault		Fuel	Avoided project	Heat rate	Emission factor
	$kgCO_2$ /GJ	$kgCO_2$ /mmBTU	Kcal /kg		KCal /kWh	Kg CO_2 /kWh
Anthracite	98.3		5,022	subcritical (Pha Lai 2)	2,402	0.99
Australian coal	89.7		6,300	supercritical	2,050	0.77
Gas	96.1	91.124		CCGT (average EVN Phu My)	1,780	0.64

112. This calculation is a function of the thermal projects displaced in each season – 100% coal in the wet season, and 100% CCGT in the dry season. Depending upon the excess capacity in the 500kV transmission grid, the ability to displace gas in the South may be limited.

113. Table 5.6 shows the results of different assumptions. If Trung Son were to displace only coal, the ERR falls from 18.9% to 16.0% (because the avoided economic cost of coal is lower than of gas). However, the impact of the higher avoided GHG emissions is an additional 2.9%, bringing the total ERR to 18.9%. Similarly, if gas were displaced during both seasons, the ERR increases to 21.3% - but since gas has lower GHG emissions, the corresponding increase in ERR when avoided GHG emissions are considered is correspondingly lower (1.6%), bringing the ERR to 22.9%.

Table 5.6: ERR Including Avoided GHG Emissions As A Function of Fuel Displaced

	Wet season	Dry season	Lifetime avoided carbon	ERR	ERR incl. GHG	Impact of GHG
			Million tons CO_2			
Displaces coal only	coal	coal	39.7	16.0%	18.9%	2.9%
Baseline (coal in wet season, gas in dry season)	coal	gas	31.7	18.9%	21.0%	2.1%
Displaces gas only	gas	gas	26.9	21.3%	22.9%	1.6%

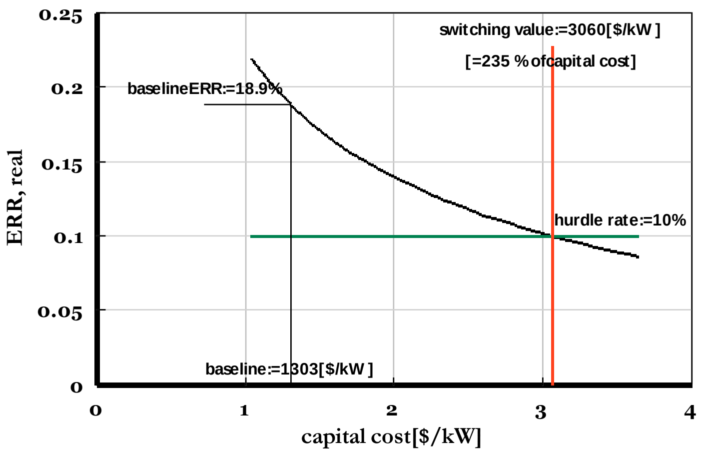
114. When life-cycle impacts are included in the avoided GHG emission calculation, life cycle avoided carbon emissions increase to 32.9 million tons CO_2, a 3.8% increase. This reflects that the lifecycle impacts of the displaced coal and gas generation (40-70g/kWh) exceed the life-cycle impacts of Trung Son (9g/kWh for reservoir emissions and 15g/kWh for hydro construction). However the ERR increases only slightly from the baseline 21.0% to 21.1%.

5.3 Sensitivity analysis

Construction cost increases

115. Construction cost increases are the bane of hydro projects. Figure 5.2 shows the sensitivity of ERR to construction cost increases. The switching value is a robust 2.35, meaning that the construction costs could be 235% higher than estimated and still meet the hurdle rate (i.e. $3,060/kW rather than the 1,303$/kW of the baseline estimate). Increases of this order of magnitude are extremely unlikely.

Figure 5.2: Sensitivity of ERR To Construction Cost Increases



116. This holds constant the *capacity* benefit of the project (which is based on the avoided capital costs of thermal generation). But it could be argued that (real) capital costs of thermal generation are correlated with the (real) costs of hydro equipment, since both are imported: if this were the case, some part of the hydro construction cost increase would be offset by an increase in the capacity benefit. But the most probable cause of hydro cost increases are geo-technical delays and unexpected civil construction difficulties, so the assumption that hydro construction costs are independent of the avoided (thermal) capacity cost is reasonable (and in any event conservative).

Impact of delay

117. The impact of delays in construction on economic returns depends upon ***when*** that delay occurs. If it occurs before construction begin (in effect delaying all costs and all benefits) there is no impact. But if it occurs

towards the end of the construction period, when most of the construction costs have been expended, and the capital investment sits idly without producing any benefit, the impact may be significant. For example, if a one year delay occurs after 5 years of construction the ERR falls from 18.9% to 17.3%; but if a one-year delay occurs after 2 years of construction, the ERR falls only to 18.1%.

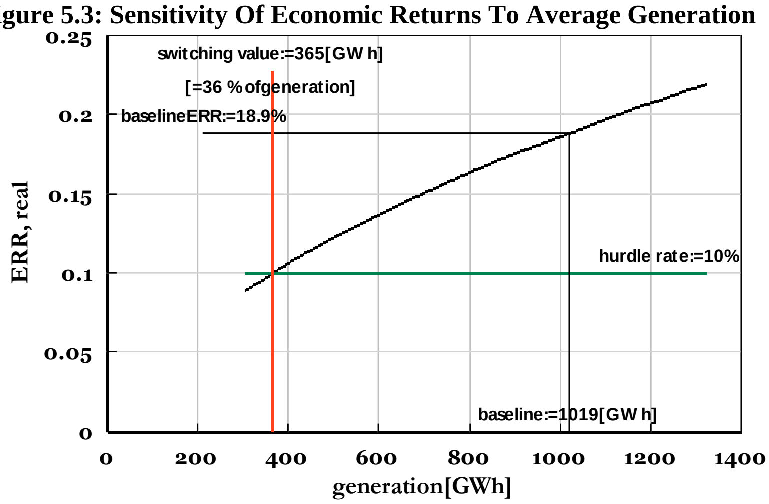
118. When construction delays do occur, there is also likely to be an additional cost (to fix the *reasons* for the delay). If there were an additional 5% of construction cost incurred during the year of delay after five years of construction, then the ERR falls from 17.3% to 26.9%; if this same delay and additional expenditure occurred after two years of construction, the ERR falls from 18.1%to 17.4%. If there were a *two*-year delay after five years of construction, and an additional 10% construction cost increase the ERR falls to 15.4%. The switching value (that brings the ERR to the hurdle rate) would require a delay of five years and a 62% cost increase.

119. We conclude that the economic returns are robust with respect to construction period delay. That construction would be 12 years instead of 7 years plus a 62% cost increase is extremely unlikely

Generation

120. The economic returns are relatively insensitive to likely deviations from baseline assumptions. As shown in Figure 5.3, the switching value for generation is 365 GWh, less than half of the baseline estimate (which also suggests that probable climate change scenarios, as may reduce the catchment area rainfall) will not have a significant impact on economic returns (discussed in more detail below).

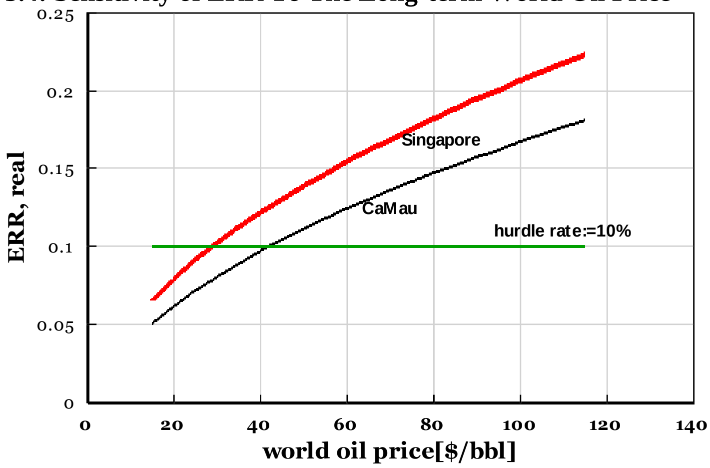
Figure 5.3: Sensitivity Of Economic Returns To Average Generation



World Oil Price Uncertainties

121. The risk to project returns lies in the *decline* of long-term oil prices (and hence in coal and gas prices which determine the avoided costs of thermal generation). On the other hand, any *increase* in oil prices will also increase the economic returns. If the linkage of the gas to fuel oil price is 90% (as argued above), the switching value is 25$/bbl (at 2009 price levels). At the 45% Ca Mau pricing formula, the switching value is 42$/bbl (Figure 5.4). Given the recovery of the world oil price from its collapse in late 2008 to the present $80-90/bbl trading range even with a very uneven global economic recovery, the likelihood of the oil price being near these switching values for any length of time is extremely unlikely (even if future oil prices were again to fall for some brief period of time during the lifetime of Trung Son during some future global recession).

Figure 5.4: Sensitivity of ERR To The Long-term World Oil Price



	gas price as fraction of Singapore HFO price	baseline ERR at	switching value
		85$/bbl	$/bbl
Ca Mau	0.45	15.2%	42
Singapore	0.90	18.9%	25

Impact of Higher Sedimentation Rates Than Expected

122. Higher than expected sedimentation is a risk faced by many Asian hydro projects. It potentially affects project economics in two ways: first, sediment accumulation may encroach into the active storage of the reservoir, reducing the ability to absorb floods, and to operate the project optimally as a daily peaking plant. Second, high sediment loads may damage turbine runner blades, necessitating expensive runner blade replacement. Both are of potential concern to lenders, and in international practice for project financings, lenders will insist on clearly articulated sediment management regimes to mitigate the first risk, and may require the funding of a major maintenance escrow fund to mitigate the second.

123. In both of the World Bank's two recent large hydro projects in Asia – the 412 MW Rampur project in India, and the partial risk guarantee (PRG) for Nam Theun 2 in Laos - sedimentation has been raised as a potential issue. In the case of Rampur, drawing upon the evidence from other nearby projects, it was found necessary to institute a strict sediment flushing regime (with 12 hours shut-down during the peak monsoon season, and shutdown when silt concentration exceeds 4,000 pm), with a corresponding reduction in the baseline ERR from 20% to 18.6%.

124. Such severe problems faced by Himalayan hydro projects are not expected in the southeast Asian area. At Nam Theun 2, exhaustive studies concluded that sedimentation problem posed little risk, short or long term. An independent AUSAID study[54] concluded that little sediment mobilisation is expected as the reservoir fills, but even were sedimentation rates greatly higher than currently expected are experienced, there would be no substantial impact on the long term viability of the dam.

125. PECC4's studies for Trung Son show a similar conclusion. Table 5.7 shows the estimated volumes of sediment expected to accumulate in the reservoir (compared with the total volume), using two different methods. To encroach on the active storage would require a sediment accumulation of 236.4 million m^3, which even in the absence of a flushing regime would take more than 150 years to achieve. To have a significant effect on the ERR, there would need to be a significant encroachment within the first 10-20 years, which Table 5.7 shows to be extremely unlikely.

Table 5.7: Estimates Of Sediment Accumulation At Trung Son

	Bruno Method		HEC-6 model
Period (year)	$V_{reservoir}$ ($10^6 m^3$)	$V_{sediment}$ ($10^6 m^3$)	$V_{sediment}$ ($10^6 m^3$)
1	349	0	0.764
10	335	14	10.7
20	320	29	22.5
30	305	44	32.5
40	290	59	44.1
50	275	74	55.1
60	260	88	64.9
70	246	103	75.5
80	231	117	84.5
90	217	132	95.1
100	203	146	104

Source: PECC4

126. Nevertheless, with 40% of the catchment area in Laos, the likelihood that this area will become heavily deforested cannot be discounted, over which Vietnam has no control. Therefore, to mitigate the risk of increased rates of sedimentation, the reinforced concrete diversion conduit located on the left side of the river at the base of the dam to bypass river flows during construction will be converted to perform as a sediment sluice during operation. The total capacity of the diversion conduit is 6,200

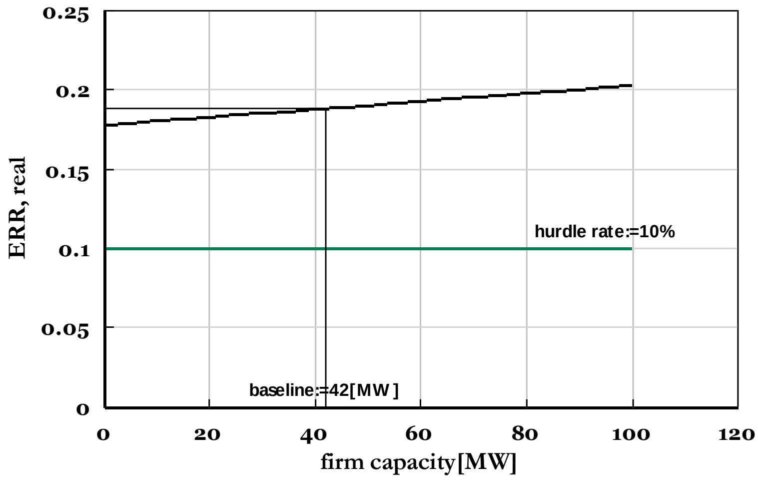
[54] AUSAID, *Review of the Nam Theun 2 Hydroelectric Dam*, Lao DPR, 21 February 2005.

m^3/sec, which is equal to the estimated flow for the 20-year flood. Additional benefits of this design option include a reduction in the size of the emergency spillway needed to pass the PMF; enable dewatering of the reservoir to 86m elevation for maintenance; ensure an environmental flow during filling and dry seasons when there is insufficient volume to run a single turbine; and allow both reservoir top water and bottom water to be discharged, thus improving downstream water quality

Firm capacity

127. The economic returns are not sensitive to the value assumed for firm capacity. The PECC4 estimate is only 42 MW, which appears low, but which is used in our baseline estimate. The firm capacity determines the value of the capacity credit counted as a benefit. As shown in Figure 5.5, even if there were no capacity credit (corresponding to zero firm capacity), the 17.8% ERR is well above the hurdle rate.

Figure 5.5: Sensitivity Of Economic Returns To Firm Capacity Estimate



O&M expenses

128. The PECC4 estimate of (fixed) annual O&M costs is 0.5% of the completed capital cost. A more realistic figure is 1-1.5%. However, as suggested by Table 5.8, within the plausible range of O&M costs the impact on economic returns is small.

Table 5.8: Sensitivity of Economic Returns to O&M Costs

	ERR
0.5%	19.3%
1.0%	19.1%
1.5% [baseline]	18.9%
2.0%	18.6%

Climate change

129. Figure 5.3 indicates that average annual generation would have to fall to 520 GWh for the ERR to fall to the hurdle rate. For climate change to produce so large a change in hydrology seems most unlikely, even under

MoNRE's high scenario of climate change. Climate change could have two undesirable impacts on hydro projects: lower dry season inflows, accompanied by an intensification of storms in the wet season (which may mean greater spill given reservoir storage limitations, and hence lower wet season generation).

130. The impact on economic returns would also very much depend upon the speed with which these changes occur. If most of the change occurs 20-30 years hence, the ERR is little affected, because it will depend mainly on inflows during the first few years of operation, when benefits have the greatest impact on ERR.

131. To assess the downside risk from climate change induced inflow reductions, the following scenarios have been assessed:

- *Scenario A*: modest decline of 5%, based on the MoNRE scenario (see Section 3).[55]
- *Scenario B*: gradual decline in generation, with 18% lower generation by 2035.
- *Scenario C*: rapid decline starting in 2015, with 16% lower inflows by 2025.
- *Scenario D*: rapid decline starting in 2011, 26% lower inflows by 2035

132. The impact on economic returns is small (Table 5.9). Even the most unfavourable reduction in generation (scenario D), as might correspond to the "runaway climate change" scenario feared by some, leaves economic returns above the hurdle rate. One may conclude that even under the most pessimistic climate change assumptions, the Trung Son economic returns are robust.

Table 5.9: Impact of Climate Change Scenarios on generation

		2018(1)	2025	2035	ERR
Baseline generation	[GWh]	1019	1019	1019	18.9%
A. Small impact (MoNRE) worst case	[GWh]	1019	978	968	18.6%
			(-4%)	*(-5%)*	
B. Gradual decline	[GWh]	1019	937	836	18.1%
			(-8%)	*(-18%)*	
C. Rapid decline starting in 2015	[GWh]	1019	856	734	17.5%
			(-16%)	*(-28%)*	
D. Rapid decline, starting in 2010	[GWh]	917	754	713	16.4%
("runaway climate change")		*(-10%)*	*(-26%)*	*(-30%)*	

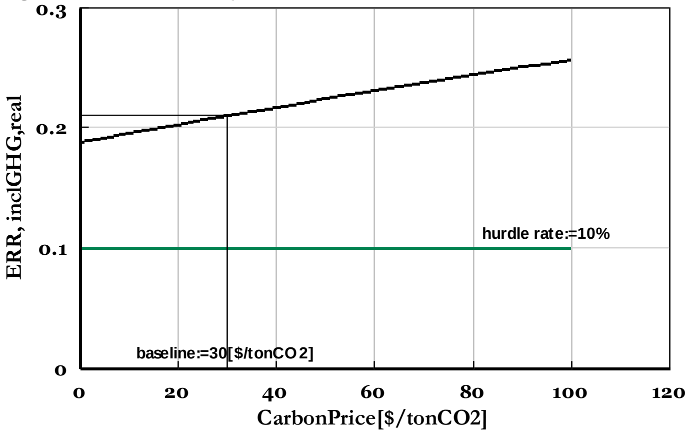
(1) 2018 is the first year with 100% of expected generation

[55] Ministry of Natural Resources and Environment, *Climate Change and Sea Level Rise Scenarios for Vietnam*, Hanoi, June 2009.

Carbon Externality Value

133. The baseline carbon value is taken as \$30/tonCO_2, constant in real terms over the lifetime of the project.[56] However, these may or may not reflect the actual long-term damage costs, for which some studies propose much higher values. As shown in Figure 5.6, the ERR including avoided GHG emissions rises from 21% at the baseline value of \$30/tonCO_2 to 24.4% at \$80/ton (Box 1).

Figure 5.6: Sensitivity of Economic Returns to Carbon Value



[56] This is based on the lower value of the social cost of carbon in the Stern Report, and does not purport to reflect the market price - which in wake of the uncertainties of the Copenhagen Conference and the global financial crisis has dropped significantly in 2010 below the 2008 peak of average CO_2 prices of \$27.9\$/ton (World Bank, *State and Trends of the Carbon Market 2010*).

Box 1: The social cost of carbon

The literature on the social cost of carbon (SCC) is growing, with estimates ranging from a small net *benefit* to costs of several hundred dollars a ton. Thus almost any estimate would find some support. Tol's 2008 meta-analysis of the peer-reviewed literature[57], which updated an earlier 2005 meta analysis,[58] cites 211 studies, found an average estimate of 120 $/ton carbon ($33/ton CO_2) for studies published in 1996-2001, and $88/ton carbon ($24/ton CO_2) for studies published since 2001. Tol concluded in the 2005 study that "*it is unlikely that the marginal damage costs of emissions exceeds $50/ton carbon ($14ton/CO_2) and are likely to be substantially lower than that*"

The Stern Review concludes:[59]
"the mean value of the estimates of the (2005) study by Tol was about $29/ton CO_2 . . though the current social cost of carbon might be around $85/ton CO_2"

Much of the economics literature on the subject is highly technical, particularly with respect to the choice of discount rate and assumptions about future global economic growth and income inequalities: in general one can say that the lower the discount rate, the higher is the social cost of carbon (a value that may also change over time). For a good discussion of these issues, and a review of the assumptions in the Stern Review, see Hope and Newbery (2007).[60]

Thus a value of $30/ton CO_2 (also used in a recent World Bank evaluation of fossil generation in South Africa) is currently appropriate for use in economic analysis.

57 Tol, R., 2008. *The Social Cost of Carbon: Trends, Outliers and Catastrophes*, Economics e-Journal

58 Tol, R., 2005. *The Marginal Damage Costs of Carbon Dioxide Emissions: An Assessment of the Uncertainties*, Energy Policy, 33, 2064-2074.

59 N. Stern, *The Economics of Climate Change*: Cambridge University Press, 2007

60 Hope, C., and D. Newbery, 2007. *Calculating the Social Cost of Carbon*, Cambridge University Electricity Policy Research Group (also in Michael Grubb, Tooraj Jamasb and Michael G. Pollitt,, editors, *Delivering a Low Carbon Electricity System: Technologies, Economics and Policy*, Cambridge University Press).

6 Risk Assessment

Approach

134. The objective of risk assessment is to derive a probability distribution of economic returns. This is achieved in a so-called Monte Carlo simulation, in which the input variables are specified as probability distributions. The ERR then is calculated for each random drawing from these probability distributions (typically repeated 5,000-10,000 times), from which the probability distribution for economic returns follows. At each iteration a new synthetic hydrology is generated, preserving the moments and serial correlation of the historical series. Figure 6.1 shows the probability distributions for the main risk variables, namely for:

- World oil price (which in turn drives the coal, gas, and fuel oil prices, and hence the level of benefits).

- Capital cost – specified as a multiplier of the baseline estimate. This is a highly skewed distribution, since cost overruns are far more likely than cost under-runs.

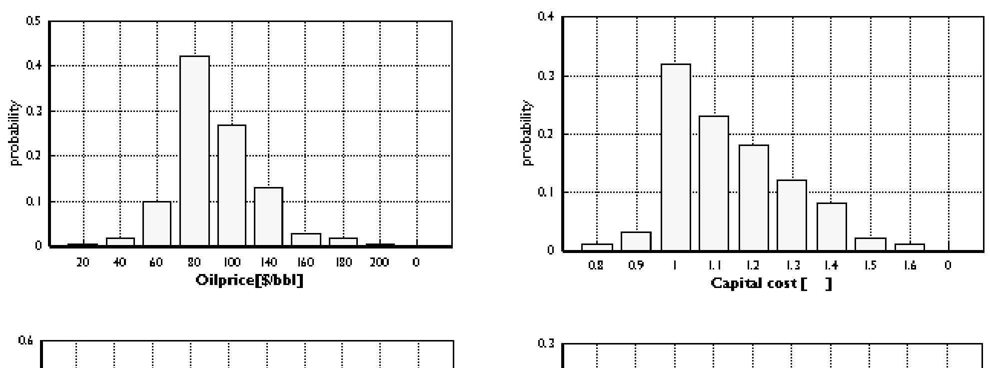
- Average annual generation – as a general proxy for hydrology risk (and with a probability distribution based on the historical variation).

- Climate change scenarios – to reflect long-term changes driven by climate change or any systematic errors in the inflow series definition. Given the uncertainties, this is specified as discrete probability distribution for the five climate change scenarios described in the previous section: the highest probability is assigned to the MoNRE base case (see Table 5.9 for the impact of each scenario on the generation estimate).

- O&M cost variations – specified as a uniform distribution of assumptions on the annual O&M cost as a percentage of capital cost (ranging from 0.5% as per the PECC4 assumption to 2% as an upper bound) – see Table 5.9.

- Value of the carbon externality – in the baseline we assume a value of $30/ton, unchanged in real terms into the future.

Figure 6.1: Input assumptions for risk assessment

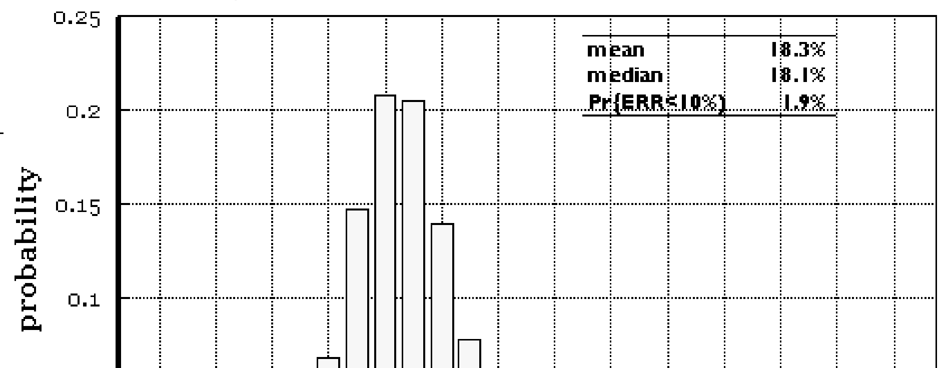


135. An important issue in such analysis is the assumption of independence – which if not met would require specification of multivariate functions (with non-zero covariance). Although one might hypothesise that higher oil prices tend to occur during commodity booms which drive up construction prices (as certainly happened in 2008), what matters is the average oil price over the first 15-20 years of the project lifetime – i.e. over the long term, whereas construction costs are locked-in over the short term, so the assumption of independence between these two most important variables is highly likely. It is also reasonable to argue that the hydrology (generation) variables are also independent of both oil prices and construction costs.

Risk assessment results

136. The result of the simulation is shown in Figure 6.2. The expected value of ERR is 18.3%, slightly lower than the baseline estimate of 18.9%: the two most important input assumptions with asymmetrical distribution – the world oil price (which governs benefits) and construction costs – roughly balance out. The probability of not meeting the assumed 10% hurdle rate for ERR is 1.9%.

Figure 6.2: Probability distribution of ERR



7 Distributional Analysis

137. The distributional analysis asks how the costs and benefits of the project accrue to the different parties. This is done by reconciling the economic and financial flows, and shows how the economic benefits are distributed among the stakeholders.[61]

In addition to the costs and direct power benefits we also consider: [62]

- *Avoided costs of GHG emissi*ons: Even if not recovered in the form of CER sales, the benefits of avoided GHG emissions accrue to the global community.
- *Avoided costs of local air pollutants* accrue to the populations in the vicinity of coal and gas burning power stations in the form of lower health care costs.
- *Flood control benefits*: accrue to the downstream communities through lower flood damages
- *Loss of forest* (as quantified by the Stockholm Environmental Institute in the Strategic Environmental Assessment
- *Increase in agricultural productivity* (a consequence of improved access and roads in the project area)

138. The analysis assesses the impacts on each of the major stakeholders, identified as

- EVN, the project owner

[61] The financial flows are based on the financial analysis report (Sierra West Consulting, *Trung Son Hydropower Project Financial Analysis*, January 2011).

[62] Some other benefits are also worth mentioning, though controversial and hence omitted from the quantification. It has long been held by economists that the health and occupational risks associated with fossil fuel extraction (notably coal mining) are internalised into wage rates and hence into fuel costs, and are not in the same category as the (involuntary) health damages from air emissions from fossil plants; therefore to treat their avoidance as an additional benefit would double count. That may well be so under the idealised conditions of perfectly open and fully competitive labour markets, but whether miners in Vietnamese coal mining areas actually have other employment opportunities (of lower health risk and lower wage rate) is unclear.

- Electricity consumers
- Project area households
- GoV (MoF) as the recipient of taxes and on-lender of IBRD funds
- PPC (Provincial People's Committees), as the presumed recipient of the natural resource tax
- IBRD as the provider of finance
- Global environment (as the beneficiary of avoided GHG emissions)

139. The financial analysis was prepared on the basis of nominal flows.[63] The results of that analysis have been converted to constant prices so that they can be compared to the economic flows at constant prices (as shown in Tables 5.3 and 5.4).

140. The results are displayed in Table 7.1 as the present values over the project horizon, at a 10% discount rate. The *columns* of this table represent the stakeholders, and the *rows* represent the transactions. Transfer payments net out of the economic analysis, so the row sums represent the net *economic* flows. The boxed entries correspond to the NPVs of economic analysis shown in Tables 5.3 and 5.4.

Table 7.1: Distribution of costs and benefits.

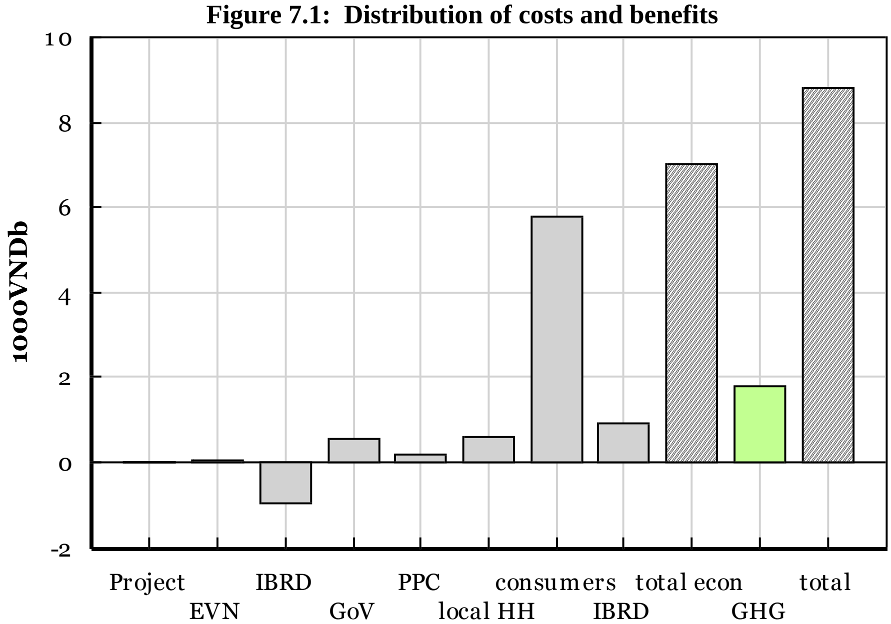
		project entity	EVN	IBRD	GoV	PPC	local/ regional economy	EVN consumers	Macro economy	total economic benefit	Global (@30$/t)	total economic benefit, including GHG
[1]	**Construction**									0		0
[2]	loan disbursement	4490		-4490						0		0
[3]	equity	1017	-1017							0		0
[4]	construction outlay	-5506							915	**-4592**		-4592
[5]												
[6]	**project debt service**											
[7]	principal	-2136		2136						0		0
[8]	interest	-1371		1371						0		0
[9]												
[10]	**operating costs**											
[11]	O&Mcosts	**-592**								-592		-592
[12]	Water Royalty	-171				171				0		0
[13]	refurbishments	**-142**								-142		-142
[14]	Income taxes	-549			549					0		0
[15]												
[16]	**benefits**											
[17]	carbon revenues	0								0		0
[18]	tariff revenue	6023						-6023		0		0
[19]	economic value of power							**11778**		11778		11778
[20]	flood control						**691**			691		691
[21]	loss of forest value						**-105**			-105		-105
[22]	post-tax returns	-1061	1061									
[23]												
[24]	GHG benefit									0	**1769**	1769
[25]	net impact	0	44	-983	549	171	587	5755	915	7038	1769	8807
									ERR>	18.9%	ERR>	21.0%

[63] Sierra West Consulting, *op.cit.*

141. The following may be noted:

- The net impact on EVN is positive: its equity contribution (negative VND 1,017 billion) is offset by the net project returns of VND 1,061 billlion.
- The net (financial) balance of the project entity is zero: the entire financial surplus (including any end-of-planning-horizon cash balances) are assumed passed back to EVN
- The only loser (i.e. net negative impact) in this table is IBRD, which is a consequence of its lending rate being lower than the assumed discount rate (10%).
- EVN consumers are the largest single beneficiaries – though this assumes that the generation cost savings from reduced thermal generation are in fact passed through to the PCs (in lower wholesale purchase costs), and hence, under the new retail tariff methodology, passed onto consumers (which is the intent of the methodology to treat wholesale power purchase from the VCGM as pass-throughs).[64]

Figure 7.1: Distribution of costs and benefits



[64] A more detailed analysis would show that some of this benefit in fact accrues to Government (i.e. tax payers as a whole) rather than consumers, because some of the benefit is represented by the avoided subsidy to fossil fuel producers. However, since electricity consumers correspond roughly to tax payers (poor rural domestic consumers who pay little if any income tax also consume very small amounts of electricity compared to large industrial, commercial and urban residential consumers), the differences are likely to be small. A more detailed analysis would also show that the apparent gain to GoV in income tax receipts from EVN's incremental profits at Trung Son would be offset by lower income tax receipts from thermal generators and their fuel suppliers. Such a broader distributional analysis goes beyond the scope of this project appraisal – where the boundaries of analysis are necessarily narrowly defined to reconcile the financial and economic flows of the project.

- The impact on “local households” is limited to the benefits of flood control and reduced forest services due to reservoir inundation, and does not include any direct consequences to families who are resettled – it is assumed that whatever benefits they derive from new homes (booked simply as an economic cost, as part of the construction cost) are exactly offset by their loss of welfare of having to move from their existing homes. Flood control benefits would extend to a much larger group of downstream communities.
- The analysis also ignores regional multiplier effects (likely to be particularly important during the construction phase) and the socio-economic costs of large construction camps.

Annex 1: Flood Control Benefits

142. Flood control benefits appear neither in the 2005 nor in the March 2008 economic analyses prepared by PECC4. This is a curious omission, given that a substantial part of the total active storage is dedicated to flood control during the wet season.

Table A1.1: Storage volumes. MCM

	MCM
140-150	78.27
150-160 (flood control)	107.73
Total active storage	187.00

Source: Storage elevation curves provided in the March 2006 report.

143. However, flood control benefits do appear in a December 2006 report.[65] According to this report, the flood control benefit is valued at VND 127 billion per year, and increases the IRR by 0.8%.

144. The economic analysis of proposed flood control alternatives is presented in Chapters VIII and IX of the PECC4 study.[66] The main premise is that:

> *flood and typhoon is VND 2,500 billion, and losses and damages caused by dyke failure is VND 2600 billion.*[67] *On average each year losses and damages caused by unsafe conditions of the dyke is VND 216.6 billion /year.*

145. It would appear that the analysis assumes that some combination of dyke reinforcement and upstream flood control storage would eliminate these damages. Four scenarios are examined, as shown in Table A1.2, that have increasing amounts of flood control storage at Trung Son. In each case the annual flood control benefit is VND 216.6 billion. For some reason no calculations are provided for zero flood storage at Trung Son.

[65] *Trung Son Feasibility Study: Supplementary Report* (Pursuant to Missive No. 6295CV-EVN-TD), December 2006.

[66] *Chapter VIII: Proposed flood control alternatives to protect the downstream area of the Ma River*, and Chapter IX: *economic analysis for flood protection downstream of Ban Uon HPP*.

[67] *Ibid*., p.141

Table A1.2: Flood control alternatives

Storage provided at Trung Son		0 MCM	112 MCM	150 MCM	200 MCM
Flood control benefit	VNDb/year		216.6	216.6	216.6
Power generation benefit	VNDb/year	733.1	708.9	681.4	651.2
Investment cost, Trung Son	VNDb		4645	4549	4571
Investment cost, downstream dyke support	VNDb		1407	1407	1343
Annual cost of the dyke system	VNDb/year		32.6	33.3	33.4

Source: PECC4, Tables 9-11,9-12 and 9-13

146. No explanation is provided for these data (which are the basis for the detailed calculations of NPV), except that some have been "calculated by PECC4". The numbers are hard to understand.

- If it is true that the variation in flood storage is for the same dam height (same maximum water level), then why does the investment cost at Trung Son stay the same when flood storage increases from 112 to 150, but increases when storage increases further to 200 MCM. If there is an explanation, it should be given. (It cannot be because of increased dam height, because in that case power generation would go up, not down).
- Both the 112 MCM and 150 MCM alternatives have the same benefits, and the same total costs (except a negligible increase in the Trung Son cost. One would have thought that if the flood control benefits are the same, then more storage at Trung Son would mean a lower cost for dyke upgrading.
- Why does the annual cost of the dyke system (for "power") increase when upstream flood storage increases. Again, since the flood control benefit stays constant, one would have thought that more upstream storage would decrease the dyke operating cost – and if it does not, then what is the point of the extra storage.

147. Several other inconsistencies across the various studies prepared by PECC4 may also be noted:

- The December 2006 report values flood control benefits at VND 127 billion/year; the flood control study values these at VND 216.6 billion/year (for the same amount of storage provided, namely 112 MCM).
- The Flood control economic analysis assesses annual benefits from power generation (for 112 MCM) at VND 708.9 billion per year, but the December 2008 economic analysis has annual benefits of only VND 627.6 billion (and as noted, does not include flood control benefits at all).
- The flood control economic analysis assumes a four-year construction time for Trung Son; all the other analyses assume a five-year construction time.

148. In any event, given the problems in the values given to wet and dry season energy, the calculations of power benefits in this analysis may be similarly unreliable.

149. We have re-estimated the impact of the proposed flood control regime using our reservoir simulation model, and using economic rather than financial benefits. The results are shown in Table A1.3. On average, without the flood control storage, generation is 56 GWh greater, and power benefits are VND 63 billion more.

Table A1.3: Impact of the operating rule

		No flood Control storage	As proposed	Difference
Flood control volume provided	MCM	0	112.1	112.1
Average energy generation(1)	GWh	994	938	-56
Average annual economic benefit	VNDb	1168	1105	63

(1) Based on daily simulations, 1958-2007

150. When one adds the annual cost of the dyke repair programme, (VND 32 billion) the total annual cost of repairs and foregone power benefits is VND 95 billion. Consequently the net annual benefits of the flood control storage are VND 200 – 95 = VND 105 billion.

Annex 2: The Potential Impact of Climate Change on the Thac Mo hydro project

151. The only study of the impact of climate change on the hydrology of a Vietnamese hydro project is for the Thac Mo project.[68] Though there are some important differences to Trung Son, the findings of that study are worth noting.

152. The basis for the Thac Mo study is the IPCC monthly climate projections for the years 2010-2039 (Table A2.1) for the scenario A1A of the CSIRO atmospheric research model, which predicts monthly temperature increases for the Thac Mo area of up to 4%, and more significant changes in precipitation, ranging from a decrease of 20% in July to an increase of 114% in February. Total annual precipitation increases by 6%. But these forecasts suggest that precipitation will increase proportionately much more in the dry season (January to May) than during the wet season (Sept-November), which runs counter to the general findings elsewhere that the wet season will become wetter, and the dry season drier.

Table A2.1: IPCC Climate Change projections for Thac Mo

	Temperature, ^{o}C				Precipitation			
	Average 1960-2020s	Projected 2020s	change		Average 1960-1991	Projected 2020s	change	
Jan	21.5	21.9	0.4	1.9%	44	51	7	15.9%
Feb	22.5	22.7	0.2	0.9%	26	38	12	46.2%
Mar	20.0	20.8	0.8	4.0%	34	73	39	114.7%
April	25.5	26.1	0.6	2.4%	48	61	13	27.1%
May	26.2	26.3	0.1	0.4%	122	135	13	10.7%
June	26.5	26.4	-0.1	-0.4%	154	167	13	8.4%
July	26.6	27.0	0.4	1.5%	170	135	-35	-20.6%
Aug	26.8	27.2	0.4	1.5%	160	168	8	5.0%
Sept	25.7	26.3	0.6	2.3%	311	313	2	0.6%
Oct	25.1	25.7	0.6	2.4%	363	397	34	9.4%
Nov	23.7	24.3	0.6	2.5%	312	309	-3	-1.0%
Dec	22.2	23.1	0.9	4.1%	110	113	3	2.7%

Source: IPCC DDC database cited in Iimi, *op.cit.*

153. The so-called VAR (vector auto-regression) model is applied to the times series of precipitation, temperature and project inflow.[69] The linear time trend for

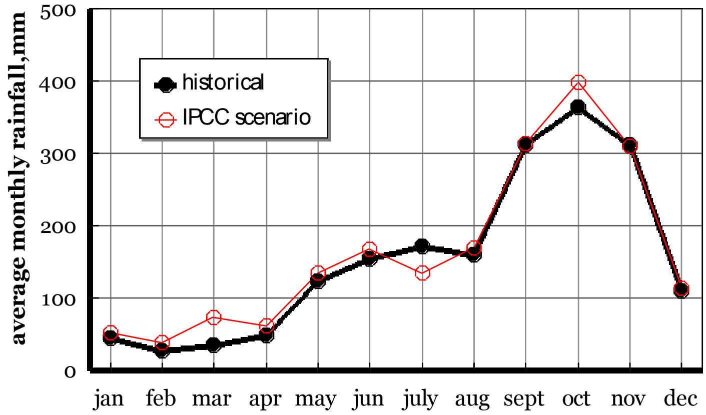
[68] Atsuchi Iimi, *Estimating Global Climate Change Impacts on Hydropower Projects: Applications in India, Sri Lanka and Vietnam*, World Bank Sustainable Development Network, Policy Research Working Paper 4344, September 2007. The other projects examined were the Upper Kotmale project in Sri Lanka, and the Vishnugad Pipalkoti project in India (all three are projects funded by JBIC).

temperature (based on the historical record) is 0.009°C per *decade*, very small but stated to be statistically significant. The predicted changes in the IPCC climate change scenario of Table A2.1 shows an increase of this rate 10-90 times greater.

154. Treating the project as run-of-river, by 2025 total generation (in the extension project) was estimated to decrease from 383 to 331 GWh, a decrease of 14%; without storage the ERR falls from 29.0% to 28.8%. When the possibility of seasonal storage is included, the ERR increases to 29.6% (or to 35% if the increased precipitation occurred already in the first year of operation).

155. Unfortunately we have been unable to sight the models used in Thac Mo feasibility study. How the details of storage were modelled, without (apparently) any integration with a reservoir simulation model, is unclear. As shown in Figure A2.1, from January to June rainfall is consistently higher in the climate change scenario, so one would expect that even a pure run of river project would have higher generation in the dry season. To assess the impact on ERR, much would therefore depend upon the assumptions about the value of the output in dry v. wet seasons.

Figure A2.1: Average monthly rainfall at Thac Mo



156. Several noteworthy differences between Thac Mo and Trung Son limit the extent to which one may draw inferences from the former to the latter project. First, as shown in Figure A2.2 the inflow seasonality is quite different; the wet season being three months later in the South (Thac Mo) than in the North (Trung Son).

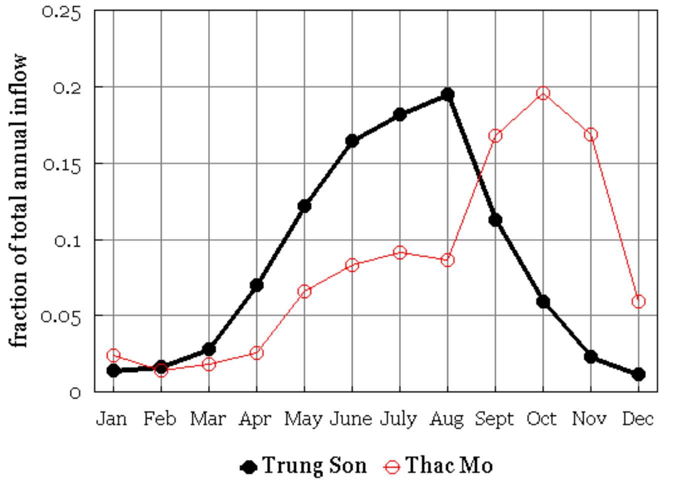
[69] The model takes the form

$$z_t=v+\sum_p A_p Z_{t-p} + c_{month}+ \boldsymbol{\rho}_{t+} u_t$$

where z_t is a 3x1 random vector (with variables for ln temperature, ln precipitation and ln inflow as average monthly discharge in cumecs*)* $\boldsymbol{A_p}$ is a 3x 3 matrix of parameters to estimated, $\boldsymbol{c_{month}}$ is a set of monthly dummy variables, $\boldsymbol{\rho}$ is a linear de-trending parameter and $\boldsymbol{u_t}$ a random residual

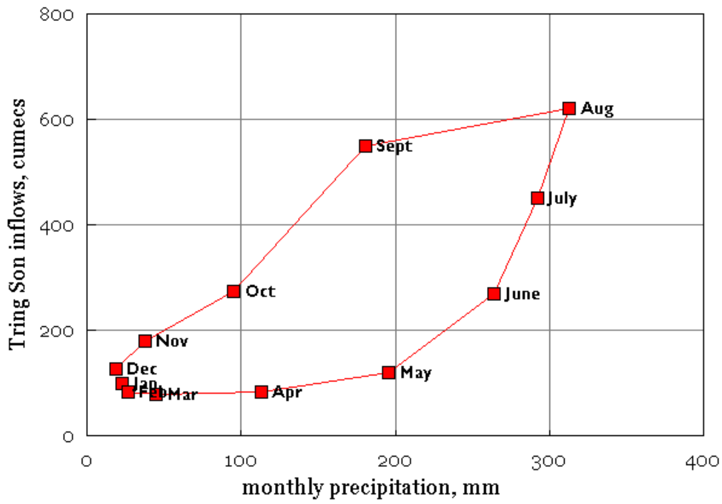
The simple correlation coefficients (for Thac Mo) are 0.849 for inflow and precipitation; 0.465 for inflow and temperature, and 0.551 for temperature and precipitation.

Figure A2.2: Seasonality at Thac Mo and Trung Son



157. Second, and more importantly, Thac Mo benefits from large seasonal storage, 1,250 MCM, equal to 174 days of storage at average inflow (83 cumecs), whereas Trung Son has only 112 MCM of active storage, equivalent to 5 days of average inflows. Moreover, the relationship of discharge to precipitation is highly specific to watershed characteristics (soils, geology, vegetation, land use), and the relationship involves important statistical time lags. For example, Figure A2.3 shows the relationship between monthly average inflows at Trung Son, and monthly average precipitation at the measuring stations used in the Trung Son project design.

Figure A2.3: Inflows and precipitation

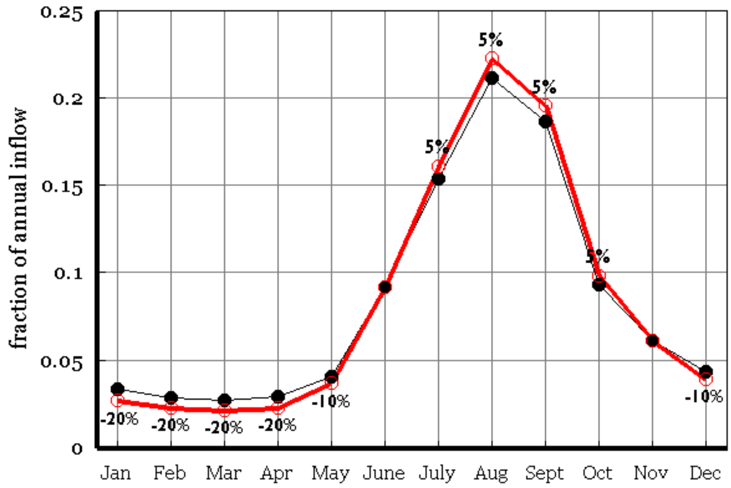


158. Between March and May, monthly precipitation in the basin increases from 50 mm to 200 mm, yet the Trung Son inflows barely increase. Only in July and August do inflows increase sharply. On the other hand, even after the rains subside in September, inflows remain high, falling off only in October and November.

159. A reasonable hypothesis for the impacts of climate change is to assume two types of impact: a trend in *total* rainfall (and hence runoff) in the Trung Son

catchment area (which the Thac Mo assessment suggests may well be an increase); superimposed on a shift in seasonality (with reduced dry season inflows but increased wet season inflows). If we assume a 15% decrease in dry season inflows, then the change in seasonality would be as shown in Figure A2.4. In the synthetic hydrology model, these changes are set for the last year of the planning horizon (year 25 of operation), with the rate at which these outcomes are reached (gradually, in a more or less linear manner, or rapidly, with much of the change in the 2015-2025 period) set in a separate random variable (to reflect the uncertainty about the rapidity of climate change impacts).

Figure A2.4: Change in seasonality



Annex 3: Alternatives to the Trung Son hydro project

Vietnam's Power Development Strategy

160. The proposed Trung Son Hydropower Project is part of a strategy that emphasizes the development of Vietnam's remaining hydro and indigenous fossil fuel resources in the short to medium term, before turning in the longer term to imported coal and pumped storage for additional peaking power and, eventually, to nuclear power.[70] The Power Master Development Plan 6 (2006-2015 with a view to 2025 – PMDP-6), which is the Government's guiding document for power sector investments in Vietnam reflects this strategy.

161. Over the past decade, most of the thermal power capacity additions in Vietnam have used domestic coal (anthracite) in the North, and natural gas in the South (notably the development of the CCGT complexes at Phu My and Ca Mau).[71] Hydropower additions planned in PMDP-6 include some 22 projects mostly in the range of 100- 600 MW, but also including Son La (2,400 MW), now under construction and the planned Lai Chau project (1,200 MW), these latter two representing the two remaining large hydro projects in Vietnam.

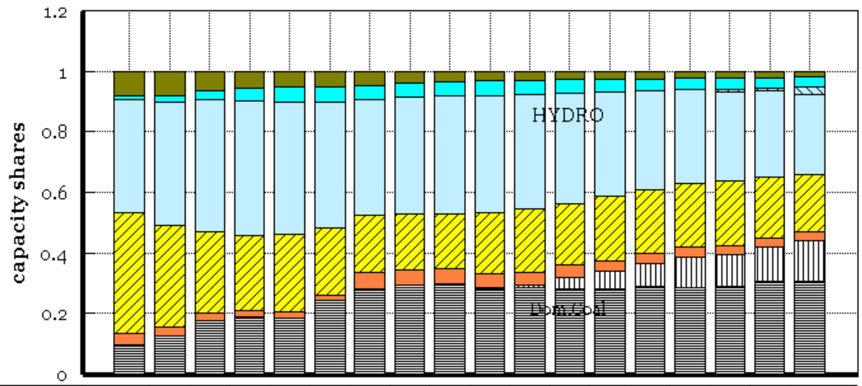
162. Given the constraints on the domestic fossil fuel and hydro endowments, beyond 2015 the choices are limited. The result is a rapidly changing capacity and energy mix. Figure A3.1 shows the evolution of this capacity mix.

163. The hydro capacity share peaks in 2011-2012 at 44%, but then falls steadily to 19% by 2025. The gas share also declines steadily from the present 40% to 19%, as does the remaining oil and diesel plant (much of which is retired in 2012-2015). Coal, presently just 10% of the total, increases to 45% by 2025: the first large imported coal project would start in 2017 on an assumed demand growth rate of 9-10 percent per year. A key conclusion is that even if large new gas fields were discovered, making possible some shift away from coal, it would not change the need to depend on hydropower with capital costs of $2,000/kW or less.

[70] Notwithstanding its appearance in beyond 2020, the most recent IoE studies show that nuclear is not likely to be cost-effective for Vietnam, given likely capital costs in excess of $3,000/kW, and rising international nuclear fuel costs. While Vietnam does have some uranium reserves, it does not have processing capability, and will therefore be exposed to the international price for nuclear fuel.

[71] World Bank, *Vietnam Power Strategy: Managing Growth and Reform*, 2006

Figure A3.1: Capacity mix



		2009		2011		2013		2015		2017		2019		2021		2023		2025
coalSteam	10%	13%	18%	19%	18%	24%	28%	29%	30%	28%	29%	28%	28%	29%	28%	29%	30%	31%
coalSteamI	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	4%	6%	8%	10%	11%	11%	14%
CFB	4%	3%	2%	2%	2%	2%	5%	5%	5%	5%	4%	4%	4%	3%	3%	3%	3%	3%
CCCT	40%	34%	27%	25%	26%	22%	19%	18%	18%	20%	21%	20%	21%	21%	21%	21%	20%	19%
hydro	37%	40%	43%	44%	44%	42%	38%	38%	39%	39%	38%	37%	34%	33%	31%	29%	28%	26%
hydroPS	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	3%
SHP/RE	1%	2%	3%	4%	5%	5%	5%	5%	5%	5%	5%	4%	4%	4%	4%	4%	4%	3%
nuclear	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
imports	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
oil,CT, other	8%	8%	7%	6%	5%	5%	5%	4%	4%	3%	3%	3%	3%	3%	2%	2%	2%	2%

Assumptions

164. In this assessment of project alternatives, it is assumed that the costs of Trung Son and its project alternatives have all been adjusted to internalize the costs of mitigating the environmental and social impacts as required by application of international best practice safeguards to hydro projects. In the case of alternatives to hydro, coal generation Vietnam already requires new coal plants to be fitted with flue gas desulfurization (FGD) and high performance electrostatic precipitators (ESP), whose capital and operating costs are reflected in the project cost estimates. Similarly, it is assumed that the same safeguard policies as apply to environment and environmental management plans, resettlement and relocation are applied across *all* project alternatives, including coal, gas, and other hydropower, and not just to Trung Son.

165. The evaluation of project alternatives for power sector expansion has traditionally required a showing of "least cost", but with a rather narrow definition of costs limited to production costs. Indeed the most recent 6th Power Master Development Plan (PMDP-6) has been criticized on grounds that the assumptions for fuel costs were based on the assumed financial costs to the sector: both domestic gas and domestic coal prices remain reflect production costs, not economic opportunity cost (though the latest gas-based generation project at Ca Mau now has a gas price linked to the Singapore fuel oil price). However, a report commissioned by the World Bank to assess the impact of using financial rather than economic prices in PMDP-6[72] concluded that the results would not have been significantly different had economic prices been used.

[72] Economic Consulting Associates, *Economic Chapter of Power Sector Masterplan No.6*, Report to the World Bank, January 2006.

Alternatives to Supply Side Expansion

166. Between 1995 and 2008, household access increased from 50 percent to nearly 94 percent; and annual per capita consumption increased from 156 kilowatt hours (kWh) to about 800 kWh. Between 2003 and 2008 installed capacity increased from about 9,300MW to over 15,800 MW, implying a demand elasticity of about two: for every one percentage point of GDP growth, the demand for electricity grows by two percent. In 2008, however, the power system was unable to meet peak demand of over 13,000 MW[73] with this level of installed capacity. This is unsurprising as reserve margins have been eroded in recent years, and are well below the 25-30 percent levels normally considered prudent for a modern power system.

167. A regional comparison of per capita electricity consumption is shown in Table A3.1 (2005 figures are the latest available for all comparable countries, 2002 for electrification rates). Consumption of electricity per capita can be expected to rise to the levels seen in China and Thailand and other middle income countries (which worldwide averaged 1,492 kWh per capita per year in 2005). Although Indonesia and the Philippines have comparable levels of per capita consumption, the electrification rate is substantially lower, and much of the supply is from mini-grids on remote islands, which do not run 24 hours a day. It is therefore reasonable to conclude that the trend for Vietnam will be towards the middle-income countries average or the regional average, suggesting continued high demand growth rates over the coming years.

Table A3.1: Per capita electricity consumption (2005)

	kWh/capita[1]	PPP $GDP/capita[1]	Electrification Rate (2002)[2]
China	1783	4100	99.0
Indonesia	509	3040	52.5
Philippines	578	3200	71[3]
Thailand	1988	6730	91.1
Vietnam	**598**	**2100**	**79.6**
East Asia	1928	-	88.8
Middle Income	1492	-	n/a

Sources: 1: World Bank: World Development Indicators Database; 2: IEA World Energy Outlook; 3: Authors' estimate. n/a: not available

Supply Side Efficiency Improvements

168. Vietnam's T&D system is relatively efficient, with 2008 losses of 11.5%. Continued upgrading is expected to bring this down to 9.6 % by 2015, and 8.5% by 2020.[74] There are some cost-effective opportunities to upgrade the rural distribution network as the low voltage assets of poorly performing local distribution utilities are transferred to EVN's power companies. This will give opportunities for EVN to pursue supply side efficiency upgrades, with financial support from donors.

[73] Due to system outages and the difference between name-plate installed capacity and actual capacity of each plant which is affected by ambient conditions, age, fuel quality and other factors.

[74] IoE estimates for the PMDP-6.

169. Detailed estimates of the possible demand reductions are not available but based on existing project experience total demand from local distribution utilities (LDUs) could be reduced by 10-20 percent. Taking demand in rural areas of about 15% of the total and total sales of 66 TWh in 2008, then rural demand was about 10 TWh per year. Demand could thus be reduced by about 2TWh per year. Assuming that all this demand occurs during four hours in the day, then total peaking capacity could be reduced by somewhere between 700 and 1,400 MW.

Demand Side Management

170. Estimating the potential for demand side management is notoriously difficult, since it must take into account the individual decisions of millions of consumers and the specific uses in several industrial sectors. A review of DSM potential for PMDP-6 suggested that evening peak demand could be reduced by 1,200 MW and the mid-day peak by 450 MW, leading to reductions in energy consumption of over 6 TWh per year. These would be achieved by programs for compact fluorescent lamps, solar water heating and improved refrigeration among others.

171. EVN's energy efficient lighting program has recently been scaled up, and more general efforts to encourage energy efficiency will be given new impetus of an Energy Efficiency Law which was reviewed by the National Assembly in May 2009.[75] In practice, the demand side management program in PMDP-6 is targeted to result in a 207 MW reduction of the peak by 2012, and 450 MW by 2015 at day time peak load.

Summary

172. Supply and demand side measures can complement each other to address the day and evening peaks. Simple arithmetic addition of the two peaks would over-state possible reductions because capacity to meet the daytime peak – which is the higher of the two and expected to become higher still as the demand profile increasingly switches to industry – is also available to meet the evening peak. Hence peak demand reduction from supply and demand would be 450 MW through efficiency measures. Total energy saved would be about 8 TWh per year. It is thus clear that even if all efficiency measures became immediately achievable they would not restore reserve margins to the desirable 25-30% level, let alone defer the construction of any plants in the capacity expansion plan.

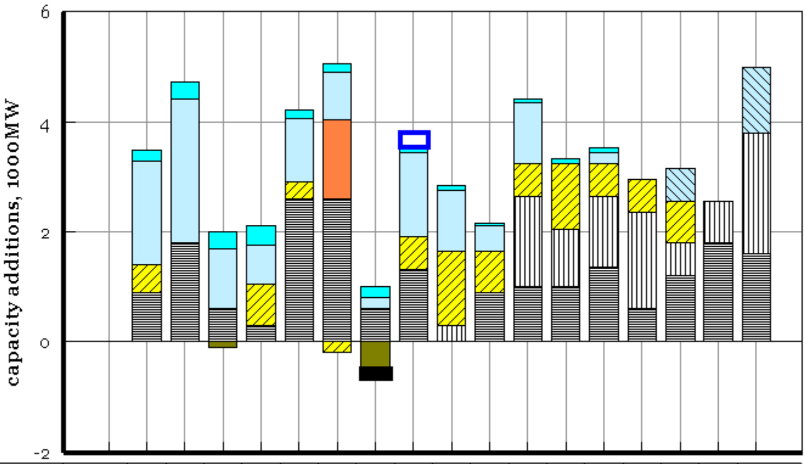
173. Although supply and demand side management options have potential and are being vigorously pursued, they alone cannot be relied on to meet Vietnam's burgeoning power requirements. Thus the proposition that additional capacity, whether from base load or peaking plants is not needed, or could be significantly deferred, by supply side efficiency improvements and DSM programs not already planned, cannot be sustained. Despite much recent progress, Vietnam remains a poor country with low per capita electricity consumption, and further demand growth is an inescapable consequence of its continued economic development.

[75] Law of Energy Conservation and Efficient Use

Hydro in the Optimum Capacity Expansion Strategy

174. Figure A3.2 illustrates the least cost capacity expansion plan by technologies.[76] Net capacity retirements are shown as negative entries.[77] Trung Son is highlighted. This shows that the projected increases in demand will be met by a combination of hydro, gas and coal, with coal, in particular, playing an increasingly important role, albeit with increasingly sophisticated technologies (such as supercritical pulverised coal) new to Vietnam.

Figure A3.2: Vietnam's capacity expansion plan



	2009		2011		2013		2015		2017		2019		2021		2023		2025
coalSteam	0.9	1.8	0.6	0.3	2.6	2.6	0.6	1.3	0.0	0.9	1.0	1.0	1.4	0.6	1.2	1.8	1.6
coalSteamI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	1.7	1.1	1.3	1.8	0.6	0.8	2.2
CFB	0.0	0.0	0.0	0.0	0.0	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
gas	0.5	0.0	0.0	0.8	0.3	-0.2	0.0	0.6	1.4	0.8	0.6	1.2	0.6	0.6	0.8	0.0	0.0
hydro	1.9	2.6	1.1	0.7	1.2	0.9	0.2	1.5	1.1	0.5	1.1	0.0	0.2	0.0	0.0	0.0	0.0
hydroPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	1.2
SHP/RE	0.2	0.3	0.3	0.3	0.1	0.1	0.2	0.1	0.1	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0
nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
oil,CT, other	0.0	0.0	-0.1	0.0	0.0	0.0	-0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
oldCoalretire							-0.2										
Trung Son hydro								0.26									

Note: Coal Steam is domestic anthracite; coalSteamI is supercritical PC using imported coal

Load Forecasts

175. The IoE load forecast, on which PMDP-6 is based shows high growth rates, and the 2009 energy growth forecast of 30 percent is already most unlikely to be met in light of economic conditions (the first eight months of 2009 shows an annualized growth rate of about 10 percent). The World Bank forecast makes more modest assumptions about short term demand growth of 9% in 2009 and 10% in 2010). Demand growth is assumed to peak at 12% in 2012 following global recovery, declining to 8% by 2019, as the expected energy intensity of the

[76] Based on the World Bank load forecast, as discussed above.

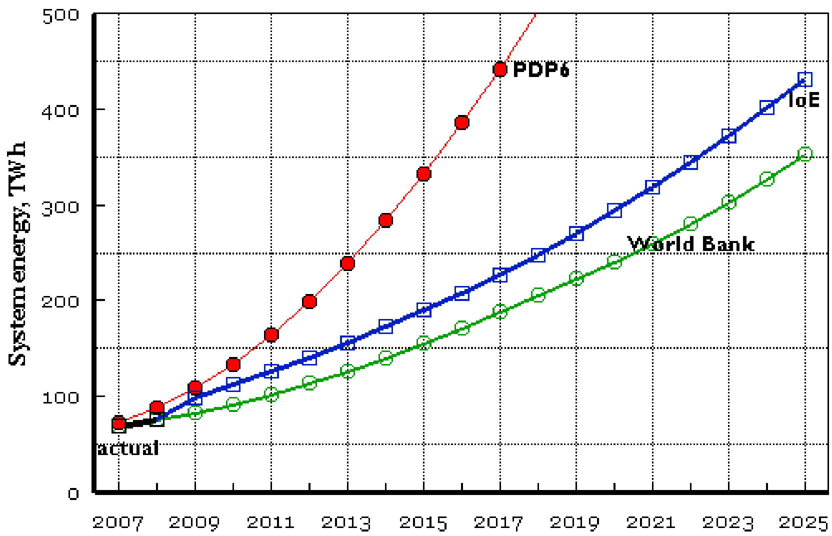
[77] The coal retirements are 4 x22MW at Ninh Binh and 2 x50MW at Uong Bi, all in 2015; the remaining retirements are 70MW of small diesels in PC2's area in 2011; the fueloil/diesel plant at Thu Duc in 2015; and 200MW of CCGT at Phu My 1.

Vietnamese economy falls (see Box 2). Table A3.2 compares the impacts of different load forecasts and Figure A3.3 illustrates this graphically.

Table A3.2: Comparison of load forecasts

	Peak load, MW		Annual energy, TWh					
	World Bank	IoE	World Bank	(%)	IoE	(%)	PMDP-6	(%)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
2007			**68.500**		**68.500**		71.875	
2008	**13.027**	**13.027**	**75.830**	**11%**	**75.830**		87.571	22%
2009	14.049	16.744	82.776	9%	98.642	30%	108.006	23%
2010	15.381	19.031	91.053	10%	112.658	14%	133.642	24%
2011	16.990	21.253	101.069	11%	126.418	12%	164.017	23%
2012	18.938	23.556	113.197	12%	140.790	11%	199.004	21%
2013	21.111	25.982	126.782	12%	156.024	11%	238.673	20%
2014	23.323	28.568	140.727	11%	172.366	10%	283.151	19%
2015	25.768	31.352	156.207	11%	190.047	10%	332.242	18%
2016	28.239	34.218	171.828	10%	208.201	10%	385.444	16%
2017	30.801	37.198	188.152	10%	227.224	9%	442.163	15%
2018	33.448	40.457	205.087	9%	248.052	9%	502.374	14%
2019	36.156	43.916	222.519	8%	270.263	9%	565.268	13%
2020	39.009	47.727	240.321	8%	294.012	9%	632.087	12%
2021	41.974	51.495	259.546	8%	318.400	8%	702.860	11%
2022	45.166	55.508	280.310	8%	344.481	8%	778.753	11%
2023	48.598	59.820	302.735	8%	372.634	8%	861.289	11%
2024	52.290	64.224	326.953	8%	401.555	8%	949.996	10%
2025	56.244	68.758	353.110	8%	431.664	7%	1,045.947	10%

Figure A3.3: Comparison of load forecasts

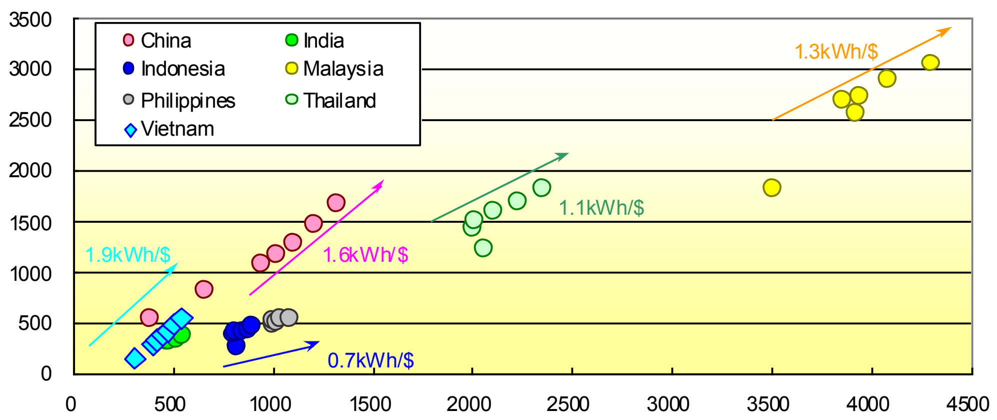


Box 2: Load forecasting

The IoE load forecast (based on the growth rates in PMDP-6) is considered by some to be unrealistically high. But even were the growth rate to be 50% less than forecast (either for reasons of lower economic growth rates in wake of the global recession, or as a consequence of a reduction in the income elasticity), the incremental capacity required over the five year period 2015-2020 will still be some 7,500MW, of which around 2,000 MW is needed immediately just to bring the reserve margin to acceptable levels.

Over the last few years, the income elasticity has been at a fairly high value of around 2 – i.e. a 1% increase in GDP results in a 2% increase in electricity demand: as shown in the figure below, this is much higher than in Vietnam's neighbors (China is 1.6; Thailand 1.1).

KWh/capita



GDP US$ Per Capita

Source: JICA, *Vietnam: A Study on National Energy Masterplan*. November 2007

Although it is reasonable to suppose that energy intensity will decline in the future, its timing is highly uncertain. As noted, the alternative World Bank forecast assumes a somewhat faster reduction in income elasticity, with a 2015 energy requirement some 34TWh lower than the IoE forecast (Table A3.2).

In any event deriving the perfect forecast is impossible: rather the questions of whether the decision to install additional capacity and individual investments are robust given the various uncertainties are more important. These uncertainties include not just the load forecast, but also international energy prices, or possible future gas field discoveries.

Hydro v. Thermal

176. The main alternative to development of the remaining large and medium hydropower sites in Vietnam is some combination of natural gas combined cycle and coal: during the wet season when hydro runs 24 hours a day, it would displace coal generation in the North (allowing baseload units to be taken out of service for scheduled maintenance); and during the dry season it would displace gas CCGT in the South, though limited to the 500kV transmission capacity and its ability to store water. At the margin, in the absence of adequate interregional transfer capacity, peaking requirements would have to be met by either LNG (as in neighboring provinces of China) or pumped storage (which is not a renewable

energy source, since it requires about 1.6 kWh of thermal (baseload) energy to produce one 1kWh of peak (pumped storage hydro energy).

177. The comparison between hydro and an alternative as a peaking plant depends critically on assumptions about the long term gas price, which, in turn, depends not just on the international oil price, but the pricing formula[78] - an analysis discussed in Section $$..

Medium hydro v. small hydro and other renewables

178. All other things equal, small hydro has a number of advantages over medium and large scale hydro projects, notably the avoidance of large scale construction camps, the avoidance of major reservoirs (and capital costs therefore somewhat lower than large hydro), and fewer project affected families (26 ten-MW small hydro projects would in aggregate have a few hundred displaced persons, as opposed to a few thousand in the case of Trung Son). And small hydro project power densities (measured as the nominal installed capacity of the power plant divided by the full reservoir area)[79] are an order of magnitude higher than Trung Son, so methane and CO_2 fluxes are of proportionately less consequence, as illustrated in Table 3. And, finally, with the CDM Executive Board's increasing scrutiny of the additionality criterion to qualify for carbon finance, CDM registration is easier to obtain than for larger projects.[80]

179. However, Vietnam's power sector plan already envisages an ambitious program of small hydro development, and more than 750 MW of small hydro (defined in Vietnam as no more than 30 MW) is estimated to be financially feasible at the new avoided cost tariff, and with the lowering of transaction costs by the new standardized power purchase agreement. PMDP-6 sets even more ambitious targets for small hydro. In other words, small hydro is not really an alternative to large and medium hydro, because the potential contributions of small hydro are already factored into the least cost plan. All of the financially feasible small hydro projects can be expected to be built over the next 10-15 years, and entirely unaffected by the presence or absence of hydro in the expansion plan.[81]

[78] Environmental considerations may constrain operation as a pure peaking plant because ramp-up times are constrained so as not to exceed increases in stream flow rates experienced under natural conditions, and because of minimum environmental flow requirements.

[79] The higher its value, the greater is the power benefit per unit of reservoir surface area, as discussed further below.

[80] Vietnam's record of successful CDM registration is poor, but MoIT and MONRE are introducing a number of measures to facilitate CDM registration; a carbon finance umbrella facility (to lower transaction costs for the small hydro projects to be financed by the World Bank Renewable Energy Development Project (approved May 2009) is under development.

[81] Other renewable energy technologies such as biomass and bagasse cogeneration will also make some contributions, but according to the recently completed Renewable Energy Masterplan, are of limited potential, and would require some additional subsidy (up to the avoided social cost) to be enabled. The development of large scale wind power is constrained by few good sites and little long-term monitoring data, and would require a feed-in tariff of at least VND 2,200/kWh, more than double the avoided cost tariff.

Table A3.3: Power densities of representative Projects

Project	Installed Capacity	Reservoir area	Power density
	MW	Km2	W/m2
Medium Hydro			
Trung Son	260	13.13	19.8
Song Bung 4	156	15.8	9.9
Small Hydro			
Sung Vui	18	3.2 ha	563
Nam Tang	6.5	0.3 ha	2167
Dak Me	4	2.1 ha	190
Can Ho	4.2	0.7 ha	600
Ha Tay	9	64ha	14

Hydro Development Strategy

180. The question of alternatives to the hydro strategy adopted by the PMDP-6 has been studied in some detail by the Strategic Environmental Assessment of the Hydropower Masterplan, recently prepared for MoIT by the Stockholm Environmental Institute (SEI).[82] This study examined a series of alternative scenarios, that ranged from a base case that included all of the hydro projects recommended by PMDP-6 (for which construction had not already begun), to three alternatives with a decreasing number of hydro projects, to a scenario in which no hydropower projects are built at all (though replaced by thermal power), and, finally, to a scenario in which no hydropower projects are built, and *not* replaced by thermal power.

181. The sequence of deletions from the PMDP-6 hydro project construction sequence was based on the overall rankings for hydro projects established in the National Hydropower Plan.[83] This calculated a "technical /economic preference index (TEPI)," and an "environmental/ social preference index (ESPI)". These were combined into a "total preference index (TPI)", and then normalized into a "normalized total preference index (NTPI)" on a scale of zero to 100 – where a low score indicates a less desirable project. Table A3.4 lists the hydro projects examined, together with their index scores (listed in descending order of economic attractiveness as measured by the benefit cost ratio).

182. In the alternative scenario 1, the 5 bottom ranked projects with TPI<60 are omitted; in scenario 2, the 10 bottom ranked projects with TPI<65 are omitted; in scenario 3, projects are omitted with TPI<75; and in scenario 4, all hydropower is omitted (in all these cases, the capacity expansion plan model replaces the lost capacity with thermal generation). In scenario 5, the model builds neither hydropower nor any replacement thermal power - thereby incurring the high costs of unserved energy.

[82] *Strategic Environmental Assessment of the Hydropower Masterplan in the Context of the 6th Power Development Plan*, Final Report, January 2009. The 22 projects are listed in Annex 2-2.

[83] SWECO-NORPLAN, *National Hydropower Master Plan Stage 2*, 2003.

Table A3.4: Hydro projects in the National Hydro Plan and their indicators

	Installed capacity	B/C ratio	TEPI	ESPI	TPI	Overall rank	Group (1)
	MW	[ ]	[ ]	[ ]	[ ]	[ ]	
Nho Que 3	190	1.99	98	48	100	1	4
Srepok 4	70	1.16	57.1	100	96.4	2	4
Upper Kontum	260	2.03	100	33	93.2	3	4
Lai Chau	1200	2.02	99.5	22	87.2	4	4
Srepok 3	220	1.48	72.9	43	78	5	4
Song Con 2	60	1.33	65.5	52	77.3	6	4
Trung Son	**250**	**1.53**	**75.4**	**32**	**74.2**	**7**	**4**
Ban Chat	220	1.66	81.8	21	73.1	8	3
Song Bung 5	60	1	49.3	65	72	9	3
Huoi Quang	520	1.34	66	35	68.7	10	3
Trung Son	80	1.12	55.2	48	67.5	11	3
Song Bung 2	100	1.04	51.2	52	66.8	12	3
Hoi Xuan	96	1.14	56.2	38	63	13	2
Hua Na	180	1.3	64	25	62.1	14	2
Nam Na	235	1.12	55.2	37	61.5	15	2
Dak Mi 1	215	1.26	62.1	26	61.1	16	2
Song Bung 4	156	1.08	53.2	37	60	17	2
Khe Bo	96	1.09	53.7	35	59.7	18	1
Dak Mi 4	180	1.04	51.2	31	55.5	19	1
Dong Nai 2	90	0.93	45.8	37	54.4	20	1
Duc Xuyen	49	0.91	44.8	28	49.1	21	1
Bac Me	250	0.86	42.4	28	47.3	22	1

Notes

Group 1 are projects with TPI<60 (and omitted from scenario 1, 2,3 & 4)

Group 2 are projects with 60<TPI<65 (and omitted from scenarios 2,3 &4)

Group 3 are projects with 65<TPI<75 (and omitted from scenarios 3&4)

Group 4 are projects with TPI>75, and omitted in scenario 4 only)

183. Each scenario was then evaluated by IoE using the WASP-STRATEGIST modeling suite, calculating the net present value (NPV) of meeting the PMDP-6 load forecast. Included in the objective function (total social cost) were:

- Cost of GHG emissions (at 25$/ton CO_2).
- Cost of local air emissions (PM10 3,880$/ton; SO_2 604$/ton and NOx 1083$/ton).
- Social and environmental costs of coal mining (19,029VND/ton in 2010), including the health cost of mining-related illnesses.[84]

[84] Including the health costs of coal mining as an externality may double count, for it has long been held by economists that the health and occupational risks associated with fossil fuel extraction (and notably coal mining) are internalised into wage rates and hence into fuel costs, and are not in the same category as the (involuntary) health damages from air emissions from fossil plants. Therefore to treat their avoidance as an additional benefit would double count. That may well be so under the idealised conditions of perfectly open and fully competitive labour markets, but whether miners in Vietnamese coal mining areas actually have other employment opportunities (of lower health risk and lower wage rate) is unclear.

- Social mitigation costs.
- Environmental costs of hydropower, including value of forests lost in the reservoir,[85] and offset by the benefits of increased agricultural production.
- The costs of potential methane emissions from reservoirs (using a global warming potential of 23 for methane).
- Multi-purpose benefits of hydro projects (notably flood control).[86]

184. As shown in Table A3.5, the deletion of any of the hydropower projects results in an increase in the NPV of the power expansion plan. In other words, not building the hydropower projects in the master plan means they must be replaced by gas or coal-fired thermal plant at an additional cost to the economy of $897 million if the five least desirable hydro projects were to be dropped, and $8,695 million if all 22 hydro projects were to be dropped. We may note that these results are independent of the highly subjective judgments about "preference" – and simply show the economic costs of not following the hydropower strategy.

Table A3.5: Alternatives to hydropower

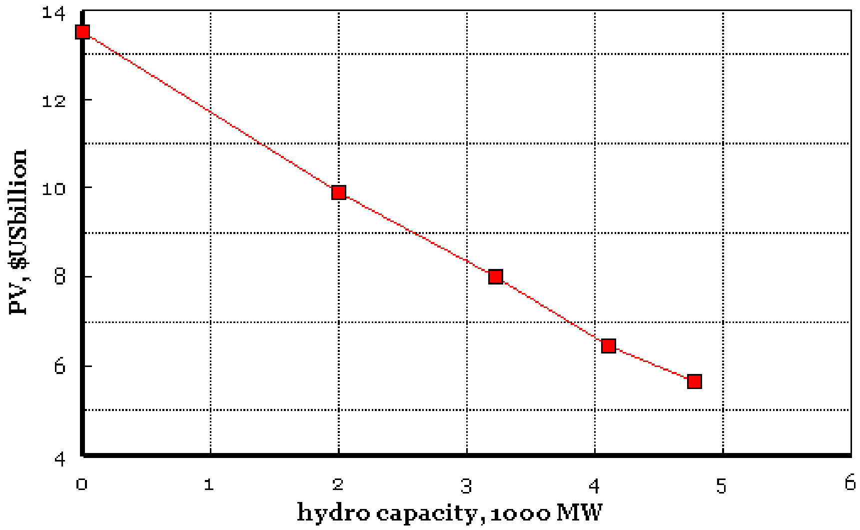
Alternative	strategy			PV	Difference in PV
		MW of hydro additions	Replaced with thermal power	$US million	$US \million
Baseline	PMDP-6	4,777		5,659	
1	Hydropower with TPI<6o	4,112	Yes	6,466	897
2	Hydropower projects with TPI<65	3,230	Yes	8,000	2,340
3	Hydropower projects with TPI<75 dropped	2,000	Yes	9,892	4,233
4	No hydropower	0	Yes	13,485	8,695
5	No hydropower	0	No	76,937	72,146

185. These results are highlighted in Figure A3.4, which shows how the addition of hydro-projects reduces the overall cost of meeting Vietnam's electricity needs.

[85] Again, as discussed further below.

[86] The flood control benefits of Trung Son are discussed in Annex 2.

Figure A3.4: MW of hydropower v. cost



186. The conclusion of this analysis is that when the social mitigation costs, the value of forest lost in the reservoir, and GHG emissions from reservoirs are properly taken into account in an economic analysis (in the above analysis, these costs are all internalized in the cost function), the strategy of hydropower generation is justified. The SEA concludes that: [87]

> *the base scenario according to PMDP-6 is clearly the best option not only from cost of supply perspective, but being reinforced when the other factors are taken into account, and even if the multi-purpose benefits are excluded*.

The SEA goes on to note that[88]

> *the level of hydropower planned in PMDP-6 is essentially a desirable one in terms of the least cost means to ensure that Viet Nam's future power needs are met. This is true even where the full range of social and environmental costs are internalized into the economic analysis of hydropower, as the full costs of alternative generation sources are even higher. As such, the significance of hydropower in contributing to overall national development has been demonstrated.*
>
> *…hydropower can contribute to development in another way* ***if*** *appropriate measures are taken: it can be a catalyst to the development of the economies of remote locations inhabited by poor and marginalized people. This is far from guaranteed and the planning of hydropower needs to include measures to take advantage of local development opportunities. Where this is the case, hydropower can provide significant benefits to local communities through improved access to external markets, new livelihood opportunities and better access to a range of services.*

[87] SEA, *op.cit.*, p.106

[88] *Ibid*, p.217.

187. The displacement of local communities is a key and controversial issue for hydropower development. It is an inevitable consequence of hydropower in many localities. Past experiences in mitigating the impact of displacement have not been adequate when compared to international good practice on resettlement. The SEA has demonstrated that this need not be the case: it is possible to provide a mitigation and development package that will provide a means to ensure that displaced people have long-term development support to restore and improve livelihoods and ultimately are better off after they are resettled.

188. In other words, provided that international good practice on resettlement and livelihood restoration is followed, development of the hydropower option is sound from Vietnam's point of view, as well as from the global climate change and local environmental impact perspectives.

Trung Son in the Hydro Development Strategy

189. Given that Vietnam should indeed be exploiting its hydropower resources as part of its overall power development strategy, the third question is whether *Trung Son* should be part of that strategy, and, if so, when should it be built. Trung Son does of course appear in PMDP-6, and in the rankings used by the National Hydropower Plan; in the SEA, Trung Son has the 7th overall rank (Table A3.4). In this section we compare Trung Son with the other hydro projects based on specific quantitative indicators, rather than the somewhat subjective "preference rankings".

Comparison of Projects

190. The National Hydropower Plan evaluated the "economic-technical" rankings on the basis of benefit/cost ratio, and then "scored" to derive a "preference ranking". The benefit/cost ratio is not in general use by the World Bank as an indicator of the economic merit of power and energy sector projects, NPV being the preferred metric. Since the information on benefits is not available (and was not reported in the SEA), a more useful indicator is the cost of energy, shown together with other salient data in Table A3.6 (and sorted in increasing order of that cost of energy).

Table A3.6: Hydropower projects in National Hydropower Plan[89]

	Capacity	Displaced persons (DP)	Area	Capital cost		Energy	Energy cost	Power density	DP/kW
	[MW]		Km^2	$USm	$/kW	GWh/year	USc/kWh	W/m^2	
Lai Chau	1,200	8,460	39.6	946.4	789	4,748	2.43	30.3	7
Nho Que 3	190	565	0.5	151.7	799	676	2.74		3
TRUNG SON	**260**	**2,285**	**12.7**	327.9	1,261	**1,058**	3.78	**20.5**	**8.8**
Huoi Quang	520	7,050	8.7	509.5	980	1,613	3.85	59.8	14
Dong Nai 5	140		4.5	234.1	1,672	709	4.03	31.1	0

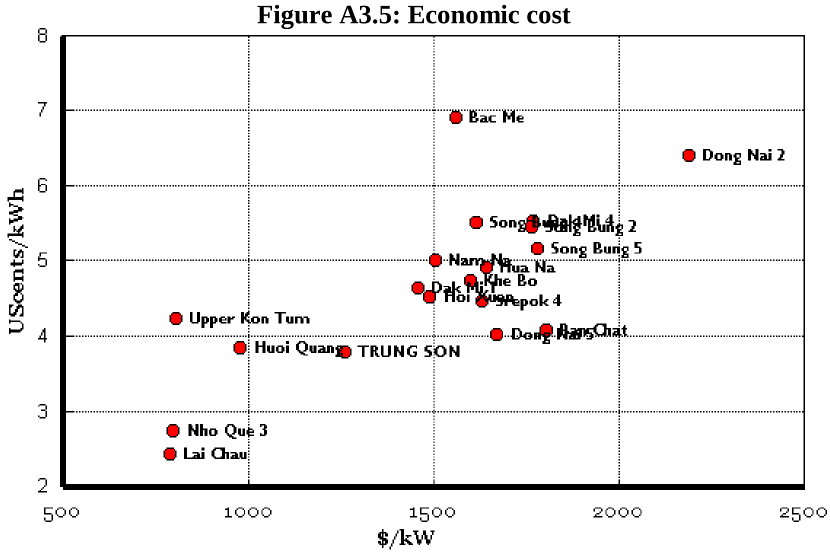
[89] The Projects in the National Hydropower Master Plan do not correspond exactly with those in the SEA discussed in the previous chapter.

	Capacity	Displaced persons (DP)	Area	Capital cost		Energy	Energy cost	Power density	DP/kW
	[MW]		Km^2	$USm	$/kW	GWh/year	USc/kWh	W/m^2	
Ban Chat	220	14,800	60.4	396.6	1,803	1,188	4.07	3.6	67
Upper Kon Tum	260	650	4.4	209.2	805	602	4.24	59.1	3
Srepok 4	70	0	4.8	114.2	1,631	312	4.46	14.6	0
Hoi Xuan	96	1,615	5.9	143.1	1,491	386	4.52	16.3	17
Dak Mi 1	215	0	4.5	313.5	1,458	824	4.64	47.8	0
Khe Bo	96	3,482	9.5	153.5	1,599	396	4.73	10.1	36
Hua Na	180	4,865	20.6	295.9	1,644	736	4.90	8.7	27
Nam Na	235	2,325	9.3	353.3	1,504	862	5.00	25.3	10
Song Bung 5	60	0	1.7	106.8	1,780	252	5.17	35.3	0
Song Bung 2	100	0	2.9	176.4	1,764	395	5.45	34.5	0
Song Bung 4	156	1,216	15.8	251.9	1,614	558	5.51	9.9	8
Dak Mi 4	180	150	11	318.6	1,770	703	5.53	16.4	1
Dong Nai 2	90	2,993	6.5	197.0	2,189	375	6.41	13.8	33
Bac Me	250	10,700	20.2	390.2	1,561	689	6.91	12.4	43

Source: Data from the National Hydro Plan. Costs have been updated to 2009 price levels. Displaced persons and reservoir area from SEA

191. As shown in Figure A3.5, Trung Son is one of the best projects by cost of energy (3rd best) and by capital cost (5th best).

Figure A3.5: Economic cost



Loss of Forest

192. The economic loss of forest value should be internalized in project economic costs. These have been estimated by the SEA as shown in Table A3.7: the estimates refer to the forest impacted in the Zone of Influence (ZoI); as with other aspects of the SEA, these data have been unchanged to allow like-for-like comparison. The ZoI is not the same as the project area (as defined in the EIA) and in fact is considerably larger. The Trung Son project has the 6th highest value of timber losses among the 16 projects for which data are available.

Table A3.7: Forest value lost[90]

	Timber from natural forest	Timber from plantation forest	Non-timber forest products	Environment services	Total		
	VNDmill	VNDmill	VNDmill	VNDmill	VNDmill	$USm	$/kW
Bac Me	0	687	0	2,544	3,231	0.2	1
Huoi Quang	13,020	298	260	12,126	25,704	1.5	3
Lai Chau	34,654	0	692	29,341	64,687	3.8	3
Upper Kon Tum	36,597	0	400	17,400	54,397	3.2	12
Dak Mi 4	26,350	0	288	12,528	39,166	2.3	13
Srepok 4	4,209	3,461	46	11,745	19,461	1.1	16
Dak Mi 1	59,104	0	646	28,101	87,851	5.2	24
Song Bung 2	28,912	0	316	13,746	42,974	2.5	25
Hoi Xuan	21,704	0	452	21,108	43,265	2.5	27
Song Bung 5	21,409	0	234	10,179	31,822	1.9	31
TRUNG SON	**64,056**	**5,248**	**1,334**	**78,269**	**148,907**	**8.8**	**34**
Khe Bo	29,195	0	608	28,394	58,197	3.4	36
Song Bung 4	75,573	0	826	35,931	112,330	6.6	42
Ban Chat	90,141	2,289	1,800	84,800	179,031	10.5	48
Dong Nai 2	42,087	4,945	460	33,930	81,422	4.8	53
Hua Na	35,437	23,967	738	107,410	167,553	9.9	55

Source: SEA

193. The value of forest lost to the reservoir is VND 148 billion ($US8.8million), or $34/kW. When included in the economic analysis, the economic rate of return decreases by about 0.5%.

Power density

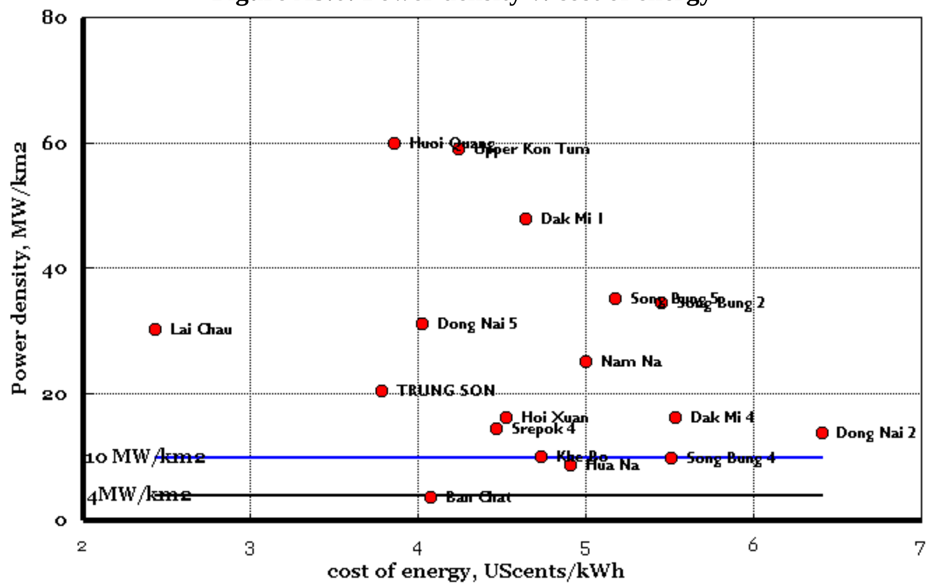
194. Methane emissions from large reservoirs have become an issue in carbon accounting, and the CDM Executive Board has issued guidelines (based largely on Brazil, the only country for which there is substantial body of empirical evidence) that are to be taken into account in avoided carbon calculations. Projects with power densities of less than 4 Watts/m^2 are ineligible for CDM, while projects with power densities between 4 and 10 W/m^2 are to subtract 9gmsCO_2 /kWh from the avoided thermal emissions (see detailed discussion in Section 4).

195. The Trung Son project has a power density of 20W/m^2,[91] comfortably above the threshold of concern, and its value is exactly at the median of the project data set.(Figure A3.6).

[90] Only projects for which data on forest loss are presented in the SEA are listed in Table A3. 6.

[91] In fact, the actual power density for the final design of Trung Son is slightly lower, at 19.8 W/m^2 However, for consistency in comparison with the other hydro projects in this section, we use the same dataset as used in the National Hydro plan.

Figure A3.6: Power density v. cost of energy

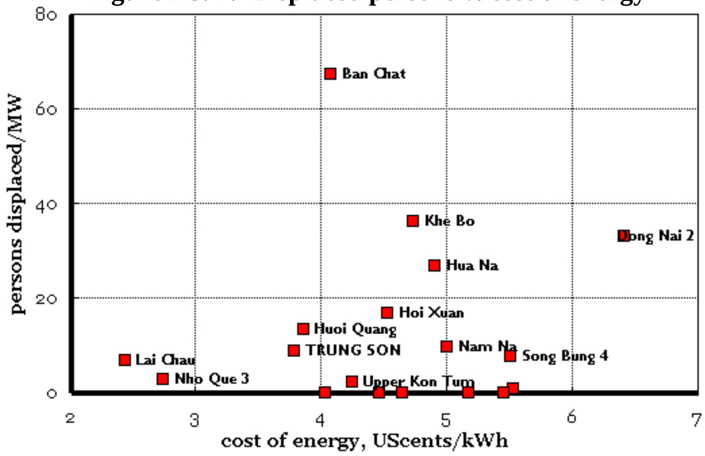


Displaced persons

196. According to the SEA, Trung Son will displace 2,285 persons[92] (Table A3.6). While this is a substantial number, when expressed as persons/MW (Figure A3.7), the figure compares favorably with the other hydro-project candidates (at 8.8 persons/MW). Moreover, the costs of the relocation and resettlement programs to World Bank safeguards standards are included in the project economic and financial capital cost (and amount to $US 29 million).

[92] The World Bank definition of displaced person (DP) is broader than the Vietnamese definition (which includes just those persons who must be relocated and resettled, whereas the World Bank definition includes any person whose standard of living or livelihood is adversely affected even if relocation is not required. According to the Trung Son Resettlement and Livelihood Development Plan, the number of affected households is 1,656 (5,976 persons, not including those impacted by the transmission line, the routing of which has not yet been determined), so higher than the estimate used in the SEA. But for consistency of comparison we use the SEA number here (since it is likely that the other projects would also show higher numbers were the World Bank definition of DP used.

Figure A3. 7: Displaced persons v. cost of energy



Hydro imports from Laos, Cambodia or Yunnan

197. There remains the question whether imports from neighboring countries would be a better option than Trung Son. The present expansion plan already includes several projects in Laos and Cambodia, under development by Vietnam-Laos joint stock companies. IoE's analysis of the least cost expansion plan, prepared as part of the project economic analysis, includes several projects in Lao PDR – see Table A3.8. The projects in Cambodia would serve peaking loads in HCMC, and do not represent alternatives to Trung Son. The Sekong 5 project would also be commissioned in 2016, and there are no identified hydro projects in neighboring countries that could be advanced in place of Trung Son. Nor is it likely that the capital costs of such other projects would be significantly lower than Trung Son, or that power densities or other environmental impacts would be significantly lower.

Table A3.8: Hydro projects in the IoE Expansion Plan

	MW		
2014	68	Khe Bo	
2014	78	Dong Nai 5	
2014	436	Sekaman1	Lao PDR
2014	120	A luoi	
2014	220	Upper KonTum	
2014	28	Srepok 4	
2014	100	Nam Mo	Lao PDR
2015	170	Dong Nai 5	
2015	540	Hoi Xuan	
2015	210	Dak Mi 4	
2016	**260**	**Trung Son**	
2016	126	Song Boung2	
2016	431	Sekong 5	Lao PDR
2017	222	Lower Srepok 2	
2017	**1200**	**Lai Chau**	
2017	210	Dak Mi 1	
2017	375	Lower Se San 3	Cambodia
2017	207	Lower Se San 2	Cambodia
2018	85	Song Buong 5	
2019	195	Hua Na	
2019	53	Hieu River	
2020	229	Nam Kong 1	

198. In any event, Trung Son is in a relatively favorable location with respect to the greater Hanoi load centre, and any imports into Northern Vietnam would involve long transmission lines (at least 5 times longer than the Trung Son lines), and correspondingly greater environmental impacts associated with transmission lines in remote forested areas. From a GHG emission reduction standpoint, a kWh from Trung Son displaces more thermal generation than a kWh generated at these more distant locations in Vietnam's neighbors.

Position in Least Cost Expansion Plan

199. The Trung Son investment decision is robust with respect to the demand forecast uncertainty. Modeling studies conducted by the Institute of Energy show that under the IoE load forecast, Trung Son is part of the least cost investment plan with a commissioning date of 2013; under the lower World Bank load forecast, the Trung Son commissioning date slips to 2016. Given a five-year construction time, and construction start in 2010, 2016 is in any event the earliest feasible implementation date. In short, whatever the load forecast assumptions, and even were efficiencies on both the supply and demand side more successful than envisaged (discussed in the first section of this report), Trung Son remains in the least cost plan.

200. In summary, among the hydro-projects examined, Trung Son has one of the lowest costs of energy (only Lai Chau has a significantly lower cost/kWh). It is a relatively efficient project in terms of its demands on the natural and social environment: the area of reservoir required (power density) and the persons displaced per MW are small. There is a potentially significant loss of forest value, but this is more than offset by downstream flood control benefits.

Site and reservoir configuration alternatives

Master Plan for Hydropower Development of the Ma river

201. The 512 km long Ma Chu river originates in Lau Chau province. It then flows through Lao territory and back into Vietnam in Thanh Hoa province, finally discharging into the East Sea. The catchment area of the river is estimated at 28,400 sq km, of which 10,800 sq km, accounting for 38%, is in Laos territory. The Ma river has two main tributaries; the Chu and Buoi rivers.

202. A Hydropower Development Master Plan for the Ma river was first prepared in the 1960s, and updated in 1988, 1998 and 2003. Subsequent minor revisions were made to include several small hydropower projects downstream of the then named Ban Uon project, which, following the identification of a precise site in the much later detailed feasibility studies (described below), is now known as Trung Son.

203. The objective of the Master Plans was to identify the optimal cascade development of the rive with a view:

- To exploit the hydro-energy potential of the river for power generation
- To provide water supply for irrigation of hundred thousand ha of agricultural land along the river.
- To reduce the downstream flood impact
- To provide water for industrial and residential uses, and

- To supplement water during dry season to reduce salinity and improve the downstream environment.

204. Requirements for flood control, water supply, and reduction of salinity were defined in the most recent Water Resources Development Master Plan for the Ma river prepared by the Ministry of Agriculture and Rural Development (MARD).

The 1998 Master Plan, and its 1999 update

205. Six hydropower projects were studied in 1998 in five hydropower cascade alternatives as presented in Table A3.9. The Trung Son project was included in all alternatives as it was considered to have the best potential. Alternative V was recommended because it had the smallest number of project affected persons, the highest hydroelectric potential, and the best financial and economic indicators.

Table A3.9: Hydropower cascade options for the Ma river (1998): high water levels (HWLs)

Project	Option I	Option II	Option III	Option IV	Option V
Pa Ma	455	455	455		
Nam Thi	390			430	
Huoi Tao	330	370			
Ban Uon(Trung Son)	170	170	170	170	180[93]
Hoi Xuan	120				
Cam Ngoc	62				

The Updated May 2001 Master Plan

206. The 2001 update covered just the Chu river, with the purpose of developing the Cua Dat project, and based on additional and updated data the on hydrology, geology, and people affected; the latest Water Resources Development Master Plan; and the pre-FS of Cua Dat project. The study recommended two projects for the Chu river including Huoi Na III (HWL of 240 metres) and Cua Dat III (HWL of 119 metres).

The 2003 Master Plan

207. The 2002/2003 Ma River Master Plan covered both the Ma and Chu rivers, again updated with the most recent data. Five of the six projects proposed in previous studies were considered in eight alternatives, as shown in Table A3.10. However the Nam Thi project was excluded.

208. The selection of the best hydropower cascade was based on (i) Reduction of downstream flood water levels (ii) reduction of downstream salinity (iii) environmental and social impacts and (iv) power generation. All of these considerations were monetised and included in the economic and financial indicators (NPV, IRR and B/C).

[93] In the 1998 Master Plan, the elevation of border with Laos was estimated at 180 metres based on a map of 1:50.000. The elevation was re-estimated in 2001 at 166.55 metres.

Table A3.10: 2003 Hydropower cascade options for the Ma river (HWLs)

Project	Option I	Option II	Option III	Option IV	Option V	Option VI	Option VII	Option VIII
Pa Ma	455							
Huoi Tao	380							
Trung Son	150	150	150	160	150	160	160	160
Hoi Xuan	80	80			70	80	70	80
Cam Ngoc	50	50	40	40				

209. Of the eight considered alternatives, alternative I, comprising five projects: Pac Ma, Huoi Tao, Trung Son, Hoi Xuan and Cam Ngoc, was selected for the following reasons:

- as having the best economic indicators.
- as providing a flood control volume of 700 million m3 meeting the requirement for reducing floodwater levels, maintaining water levels at the level of the 50year flood at Ly Nhan not to exceed 12.7 m.
- as the ability to supplement 71.3 - 80.5 cumecs to the downstream requirement for water supply and reduction of salinity.
- as providing the maximum exploitation of hydropower potential of the river with total installed capacity of 772 MW and annual output of 2.2 billion kWh.

210. Among the hydropower projects in alternative I, Trung Son was considered the best project. It features good technical conditions, and has reservoir of sufficient size to provide downstream flow augmentation. It is economically and financially viable and has smaller environmental and social impacts compared to the other projects in the alternative. The other projects had higher numbers of affected persons and hence higher compensation and resettlement costs. Trung Son was recommended as the first project for development on the Ma river. The main benefits of the project were identified as follows:

- Provides a flood control of 200 million m^3.
- Maintains the salinity level at Ham Rong less than 2.48‰.
- Provides 260 MW of power with annual output of 1.015 billion kWh
- The project would require relocation of 1,338 HH (6,793 people) in the two provinces of Thanh Hoa and Son La

The main parameters of the projects in alternative I are provided in Table A3.11.

Table A3.11: Hydro projects on the Ma river (Alternative I in the 2003 Masterplan)

Parameter	Unit	Pa Ma	Huoi Tao	Ban Uon	Hoi Xuan	Cam Ngoc	Total
Catchment area	Km^2	3480	6430	13360	13650	17250	
Annual flow	M^3/s	68.48	121.06	250.05	255.50	334.13	
High water level	M	455	380	150	80	50	
Reservoir area	Km^2	26.7	103.7	12.8	5.1	43.5	
Active volume	Mil. m^3	564.6	2716.0	302.3	17.1	406.8	6136
Dead volume	Mil. m^3	313.3	1598.0	73.7	19.2	106.9	4006
Total volume	Mil. m^3	895.9	4614.4	376.0	36.3	513.7	2125
Flood control volume	Mil. m^3	200	300	200	0	0	700
Installed capacity	MW	80	180	280	92	145	772
Annual output	Gwh	313	741	1047	404	583	3084
People to be relocated	people	21277	41773	6793	8259	34732	112834
Agricultural land flooded	ha	1220	3300	736	190	2580	8026
Investment cost	Bil VND	4252	7098	3935	2100	4561	21947
NPV				943			636.1
IRR				15.84			12.15
B/C				1.31			1.08

211. In addition to the 2003 study approved by MoIT on 31 March 2005, five small hydropower projects downstream of Trung Son were subsequently included in minor revisions:

- Thanh Son: included in 2008, immediately downstream of Trung Son (Trung Son) project with a HWL of 90m.
- Ba Thuoc 1 and 2: included in 2008, downstream of the Hoi Xuan project with HWLs of 54 m and 41 m respectively.
- Cam Thuy 1 and 2: further downstream of Ba Thuoc 2 with HWLs of 24m and 16 m.

Selection of the dam site in the pre-feasibility study.

212. The pre-feasibility study evaluated three alternative sites along a 19.2km stretch of the Ma river for the Trung Son project, all in Quan Hoa district (Table A3.12):

- Alternative I: at Phu Thanh and Thanh Son
- Alternative II is further upstream of alternative I at Trung Thanh and Thanh Son;
- The most upstream alternative, alternative III, is at Trung Son

Table A3.12: Site alternatives in the Pre-feasibility Study

Parameter	Unit	Alternative I	Alternative II	Alternative III
Catchment area	Km^2	13430	13296	13175
Annual flow	m/s	244	242	239
High water level	meters	150	155	165
Reservoir area	Km^2	135	140	157.5
Active volume	Mil. m^3	281.1	253.1	97.9
Total volume	Mil. m^3	714.0	638.6	399.3
Flood control volume	Mil. m^3			
Installed capacity	MW	297	295	290
Annual output	Gwh	1168.2	1150.9	1166.0
HH/People to be relocated	HH/people	1372/6998	1148/5656	416/2114
Land flooded	ha	2286.1	2287	1552
Investment cost	VNDbillion	4587	4471	2876
NPV	VNDbillion	418	405	1011
IRR	%	11.2	11.2	13.5
B/C	[ ]	1.11	1.11	1.32

213. Various combinations of high and low reservoir levels and installed capacity were studied at this stage, and the resulting economic evaluations compared against potential project risks, and environmental and social considerations. The study concluded that

- Alternative I has the most unfavorable geo-technical conditions, given its close proximity (3km) to an active fault. Alternative II has similar geological conditions, but the third alternative is the most distant to the fault (15km distant).
- Alternatives I and II have significantly larger reservoir storage volumes, but a lower generation head, and therefore provide almost the same energy output as alternative III.
- Because there is no large tributary along this stretch of river, the inflows do not differ greatly at the three sites.
- Alternatives I and II require higher investment costs due to the need for larger dam structures.
- Alternatives I and II also have a higher number of project affected persons, and higher costs for relocation and resettlement.

Consequently, alternative III, the site at Trung Son, was selected as the preferred option.

Feasibility study selection of the high water level

214. To avoid affecting Lao territory, the high water level (HWL) should not exceed 164m. Two lower HWLs were also examined (162m and 160m). There is relatively little difference between the in economic indicators among the three options, and therefore the lowest of these three levels was selected, thereby minimizing the reservoir area at HWL, minimizing the related environmental impacts, and minimizing the possibility of disturbance to Lao territory.

Annex 4: The IoE Power System Modelling Studies

215. The Institute of Energy has conducted a least cost planning study to assess Trung Son's role in the least cost plan. This study had the following objectives:

- to determine whether Trung Son is in the least cost plan; and, if so, when is its optimal commissioning date
- to examine the robustness of the Trung Son investment decision to the various uncertainties, notably regarding the demand forecast;

216. The details of this study are provided by IoE in their report, [94] to which the reader is referred for more information about assumptions and results, and for a detailed description of the models used and their limitations.[95] For each of the scenarios, the model is run with and without Trung Son.

217. When the model is run *with* Trung Son as a candidate, the optimal timing of Trung Son is determined: the model would be free not to build Trung Son at all if more economic alternatives were available. In fact, in ***all*** cases examined, Trung Son is built. The economic analysis report shows that the switching value of the natural gas price would have to be 1.5$/mmBTU (corresponding to a world oil price of 15-20$/bbl) for CCGT to be a more cost effective option to meet the equivalent energy and capacity.[96]

218. In the *without* Trung Son counterfactual, the model is allowed to adjust the capacity expansion plan. The adjustments if Trung Son is not built may take some or all of the following forms

- Adjustment in the timing of the remaining hydropower projects in the expansion sequence
- Bringing forward the commissioning dates of thermal units (to replace the capacity not provided by Trung Son)
- Adjusting the dispatch of thermal power plants to replace the energy not provided by Trung Son.

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[94] Institute of Energy: *Review of Power System Expansion Planning in Vietnam*, Report to the World Bank, June 2009.

[95] The power planning process in Vietnam is also reviewed in Mario Pereira, *Review of Power System Expansion Planning in Vietnam*, report to the World Bank, June 2008; and in Duncan Wilson, *Review and Assessment Report for the Development of Least-Cost Planning and Implementation Procedures for the Vietnam Competitive Generation Market*, report to Electricity Regulatory Authority of Vietnam, August 2008

[96] *Economic Analysis Background Report*, Section 7.

219. The optimal combination of these adjustments then defines the incremental costs if Trung Son is not built, and defines the environmental benefits due to the avoided GHG and local air pollutant emissions.

220. The main results of the modeling results are as follows:

- In all cases examined, Trung Son appears in the least cost expansion plan.
- In the high (IoE) load forecast, Trung Son is built at the earliest allowable start-up date, which is set at 2013. It is of course very unlikely that this could be achievable in practice, given a 5-year total construction time. However, an early allowable start-up date was set in the model to limit the impact of exogenous assumptions. Under the low (World Bank) forecast the startup date slips to 2016.
- Trung Son's impact on the capacity expansion plan is to displace a 300 MW coal unit in the North that would otherwise enter the optimal plan in 2016.
- The 1,200 MW Lai Chau hydro project – based just on modelling expansion plan criteria, always appears later than the Trung Son project (and in the low load forecast, enters in 2017, one year later). However, in reality, its timing would be dictated by other constraints (since being part of a cascade immediately upstream of Son La, its construction needs to be completed before full flooding of the Son La reservoir).
- The timing of Trung Son is unaffected by international fuel prices or a CO_2 tax. A CO_2 tax of 15$/ton has minimal impacts on the expansion plan, though load factors at CCGTs are somewhat higher (and lower at coal plants): only at a tax of 60$/ton CO_2 does one observe significant expansion plan impacts (at this level nuclear power may become economic, depending on assumptions on capital cost).