Mekong River Commission

Basin Development Plan Programme, Phase 2

Assessment of basin-wide development scenarios

Technical Note 7

Power Benefits

(Work in Progress)

February 2010

<u>Note to the reader</u>

This series of technical notes is prepared to serve facilitation and discussion on the assessment of basin-wide development scenarios of the Mekong Basin by stakeholders in the basin countries. The assessment process is continuing and feedback on the initial findings is requested.

Mekong River Commission

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Abbreviations, symbols and acronyms

$	United States Dollar
Cents	US Dollar Cents
EPC	Engineering, Procurement and Construction
GWH	Gigawatt-hour = 1000 MWH
IDC	Interest During Construction
IRR	Internal Rate of Return
Kg	Kilogram
KW	Kilowatt
KWH	Kilowatt-hour
LMB	Lower Mekong Basin
MCM	Million Cubic Meters
MRC	Mekong River Commission
MW	Megawatt = 1000 KW
MWH	Megawatt-hour = 1000 KWH
M$	Million US Dollars
PEM	Power Evaluation Model
TCM	Thousand Cubic Meters
Ton	Metric Ton = 1,000 Kg
PPA	Power Purchase Agreement
PV	Present Value

1 INTRODUCTION

1.1 Basin Development Plan

The second phase of MRC's Basin Development Plan Programme (BDP2) is designed to provide an integrated basin perspective through the participatory development of a rolling Integrated Water Resources Management (IWRM) based Basin Development Plan. The plan will comprise the following elements:

- ***Basin-wide Development Scenarios***, which will provide the information that Governments and other stakeholders need to develop a common understanding of the most acceptable balance between resource development and resource protection in the Lower Mekong Basin, taking into account developments in the upper Mekong Basin. The results will guide the formulation of the IWRM-based Basin Development Strategy.

- ***An IWRM-based Basin Development Strategy***, which provides a shared vision and strategy of how the water and related resources in the LMB could be developed in a sustainable manner for economic growth and poverty reduction, and an IWRM planning framework that brings this strategy into the various transboundary and national planning, decision-making and governance processes.

- ***A Project Portfolio*** of significant water resources development projects and supporting non-structural projects that would require either promotion or strengthened governance, as envisioned in the 1995 Mekong Agreement.

The preparation of the Plan will bring all existing, planned and potential water and related resources development projects in a joint basin planning process, through a combination of sub-basin and sector activities, and a basin-wide integrated assessment framework.

1.2 Formulation and Assessment of Scenarios

The formulated basin-wide development scenarios represent different levels and combinations of sectoral development and consider the many development synergies and trade-offs among the different water-related sectors, such as irrigation and hydropower synergies and hydropower and fisheries tradeoffs. The table below summarizes the scenarios agreed by the countries.

Table 1: Considered scenarios

No.	Short Title	Full Title	Development Period	Interventions/Projects
Baseline situation				
1	BS	Baseline scenario		Year 2000 infrastructure including existing HEP dams

Definite future situation				
2	2015-UMD	Upper Mekong dam scenario	2000 - 2015	Baseline extended to include the full HEP cascade on the Lancang
3	2015-DF	Definite future scenario	2000 - 2015	2015-UMD plus 25 additional HEP dams in LMB and 2008 irrigation and flood measures
Foreseeable future situation				
4	2030-20Y	LMB 20-year plan scenario	2010 - 2030	2015 DF plus 11 LMB mainstream dams and planned tributary dams, irrigation, and water supply
5	2030-20Y-w/o MD	LMB 20-year plan scenario without mainstream dams	2010 - 2030	As above, excluding 11 LMB mainstream dams
6.1	2030-20Y-w/o LMD	LMB 20-year plan with 6 mainstream dams in Northern Lao PDR	2010 - 2030	As above plus 6 LMB mainstream dams in upper LMB
6.2	2030-20Y-w/o TMD	LMB 20-year plan with 9 mainstream dams	2010 - 2030	2030-20Y, excluding the two Thai mainstream dams
6.3	2030-20Y-w/o CMD	LMB 20-year plan with 9 mainstream dams	2010-2030	2030-20Y, excluding the two Cambodian mainstream dams
7	2030 – 20Y Flood	Mekong delta flood management scenario	2010 - 2030	Baseline plus 3 options for flood control in Cambodia and Vietnam Delta
Long term future situation				
8	2060-LTD	LMB long-term development scenario	2030-2060	2030-20Y plus all feasible infrastructure developments in LMB
9	2060–VHD	LMB very high development scenario	2030-2060	As above, extended to full potential infrastructure developments

First the development scenarios are assessed on a range of hydrological indicators to evaluate future water availability and use, and the flow changes caused by different levels of water use, taking into account the existing and planned developments in the Upper Mekong Basin. The scenarios for the foreseeable and the long term future will be assessed with and without consideration of climate change impacts. The results are then fed into the 'assessment of the transboundary economic, social and environmental impacts and IWRM requirements'.

In these assessments, the development scenarios are evaluated against 13 main indicators that can measure how well each scenario achieves the countries' objectives of economic development, social development and environmental protection. As well, a basin wide 'equity' indicator is included that measures the degree of 'equitable development' between each country that each scenario produces, taking into account benefits from existing water use and further planned investments in each country.

After basin-wide consultations on the assessment results, the countries will determine which development scenario would provide the most acceptable balance between economic, environmental, and social outcomes in the LMB, and would bring mutual benefits to the LMB countries. It is noted that in choosing a development scenario, the LMB countries are not committing to a particular set of projects (which are in any case subject to feasibility studies, EIAs etc.), but are identifying a development space within which they can plan and work. Conflicts and trade-offs may occur, but within the agreed vision and outcome of the IWRM-based Basin Development Strategy.

1.3 Objective

This paper describes the methodology and results of the calculation of the net power benefits of the hydroelectric projects included in each of several basin development scenarios for which a full assessment of impacts is being made by MRC. The report will discuss the criteria used in establishing the cost and the value of power for each project and will provide the results of the calculation of net power benefits for each of several scenarios identified by MRC. The description of criteria for identifying scenarios and for selecting the hydroelectric projects to be included in each scenario is not part of this report.

The hydroelectric projects under consideration are located in the Lower Mekong Basin in Laos, Thailand, Cambodia and Vietnam. Several of the projects located in Laos and Cambodia are not planned exclusively for domestic electricity supply but include a considerable export component. Therefore, the analysis must consider the value of the projects in all the markets where it is envisaged that power will be supplied.

1.4 Calculation and Presentation of Results

The analysis involves many assumptions and a considerable number of calculations. It is useful if those assumptions can be easily changed to evaluate the sensitivity of the results. For this reason the analysis is prepared in the form of an electronic spreadsheet with clear indication of input values. For future reference in this report, the electronic spreadsheet will be called Power Evaluation Model (PEM). The primary input and output of the analysis is contained in page "SUMMARY" of PEM.

1.5 General Economic Considerations

In this analysis all monetary values are expressed in 2009 dollars and the analysis is conducted in "real terms". That means that all monetary values reflect the purchasing power of dollars in 2009. Any value expressed in 2009 dollars applicable to a future year can be converted to "nominal" dollars of that year by applying the general rate of inflation between 2009 and that future year.

A generalized economic discount rate of 10% is used and is deemed to represent the opportunity cost of capital in the region over the planning horizon.

2 REPLACEMENT COST OF POWER

2.1 Conceptual Aspects

The economic evaluation of hydroelectric projects involves the calculation of the least cost of power generation that would be an alternative to hydropower. The least cost alternative is a thermal plant using fossil fuel because, in general terms and including equivalent power reliability considerations, all other generation technologies using renewable resources are more expensive than hydroelectric generation.

There are many thermal generation technologies in use today and the choice depends in the availability and price of fuels and the scale of the power systems to be supplied. Key references used for understanding the relevant characteristics of the power sectors of each of the four countries involved are as follows:

Thailand:	Draft Mekong River Basin Hydropower Sector Review in Thailand, Thai National Mekong Committee, January 2009.
Vietnam:	Hydropower Sector Review in Vietnam, Nguyen Huy Hoach, November 2008.
Lao PDR:	Power Demand Forecast, JICA January 2009. Hydropower Expansion Progress, Chansaveng Boungnong, August 2008.
Cambodia:	Hydropower Sector Review in Cambodia, Dr. Narith Bun, November 2008.

2.2 Expected Generation Expansion

The power generation structure of Lao PDR will not change and will continue to be predominantly hydro. Indeed the only reason for Lao PDR to use any other generation technology but hydropower is the cost of expanding and maintaining the transmission grid to reach every load.

Thailand will move towards reducing its dependency on gas and coal with as much hydro as it can competitively import. Natural gas is a fuel that can be used advantageously in several sectors including industrial heat, residential cooking and transport and therefore its use for power generation may not be the most efficient from an overall national energy planning perspective.

The Cambodia power sector is expected to change radically from its current almost complete oil dependency to a mix of hydro and coal.

Vietnam has ambitious plans for new coal and nuclear capacity by 2020 but that capacity and the expected capacity of new domestic hydro still leaves a large gap against expected demand. That gap will likely be filled by imports of hydro from Lao PDR, more aggressive coal or nuclear development or, more likely, a combination of all three.

2.3 Viable Thermal Alternatives

Thermal generation alternatives are combinations of fuel and generation technology. Not all technologies can burn all fuels and generally, the most expensive technologies to build can burn cheaper fuels and vice versa.

Coal is the cheapest fossil fuel but can only be burned in steam plants which are expensive to build. Natural gas can also be burned in steam plants but it is cheaper and more efficient to use it in a technology called “combined cycle” that consists of a combination of combustion turbine (similar to jet engines used in aircraft) and steam turbines. Steam turbine and combined cycle technologies are capable of large scale generation with capacities of up to several thousand megawatts per plant.

Two oil products are of common use in smaller scale power generation. Distillate fuel oil, also known as "diesel oil" is very expensive compared to natural gas or coal but can be used in low cost diesel engines that are only practical with capacities of just a fraction of one megawatt. These engines are relatively light machines, similar to diesel engines used in trucks and are known as "high speed diesels". Residual oil, also known as "bunker oil", has a lower cost, comparable to that of crude oil and can be used in heavier diesel engines with capacities of up to 30 MW. These engines are also used in ships and are known as "low speed diesels". Their cost is comparable to that of combined cycle machines.

Nuclear power is, of course, a viable technology for the scale of the systems of Thailand and Vietnam but its use as a thermal reference for hydroelectric project evaluation is not practical because the full extent of nuclear generation cost, including fuel disposal and plant decommissioning, is very complex to evaluate.

In summary, in the absence of hydroelectric and nuclear power, large systems would lean towards combined cycle technology if they had availability of natural gas and steam technology using domestic or imported coal if they did not have gas. Small systems would start with high speed diesels for very small isolated loads, moving to low speed diesels as more loads becoming interconnected and finally would start moving into combined cycle or steam turbine technologies depending on the availability of natural gas.

2.4 Fuel Cost

Fuel prices have been very volatile in the past two years and this complicates the use of any specific value. Current prices for oil products can be derived by using the cost of crude for bunker and approximately 50% above the cost of crude for diesel. Current cost and natural gas prices can be estimated based on recent transactions in Vietnam and Thailand.

However, energy observers agree that it is highly probable that fuel prices will, over the foreseeable future, increase in price at a higher rate than the general inflation that could be expected. This increase in price above the general level of inflation is called escalation. In particular, fuels that are of practical use in the transportation sector, such as oil or natural gas, are likely to experience the highest escalation in price. For this reason, current prices are not appropriate to be used in an analysis based on real terms since they could not be converted into nominal prices by merely applying inflation.

To account for the real future cost of replacement power the current prices have been escalated, over the next 20 years, at the expected rate of increase in price over general inflation. The resulting annual prices are then levelized for the 20 year period using the economic discount rate. The levelized value is such that the present value in 2009 of a string of constant annual levelized values is the same as the present value of the specific annual escalated values.

The values used for current fuel prices and for the assumed fuel price escalation are variables in the "SUMMARY" page of the Power Evaluation Model, PEM. These values and the resulting levelized fuel price are shown in Table 1.

Table 1 – Current and Levelized Fuel Prices

Fuel Type	Diesel	Nat.Gas	Bunker	Coal
Fuel Price Trade Unit	$/bbl	$/TCM	$/bbl	$/ton
Reference Heat content per Trade Unit in Mbtu	5.54	36.27	5.81	22.00
Current fuel price $/Mbtu	16.63	6.60	8.80	2.41
Current Fuel Price $/trade unit	92.06	239.37	51.15	53.02
20 Year - Mean Annual Escalation Rate of Fuel Prices	6.0%	5.0%	6.0%	2.0%
20 Year Fuel Price Levelized Value	149.94	385.69	89.33	68.09

Notes:
Bbl = American Barrel = 42 American Gallons = 158.97 Liters
TCM = Thousand Cubic Meters = 35,314.7 Cubic Feet
Ton = Metric Ton = 1,000 Kilograms = 2,204.6 Pounds
Mbtu = Million British Thermal Units = 251,996 Kilocalories

2.5 Variable Cost of Replacement Power

The cost of fuel is the primary component of the variable cost of power from thermal plants. This component is obtained by combining the cost of the fuel with assumptions on the heat content of each fuel and the thermal efficiency or "heat rate" of each generation technology. Other components of the variable cost are then added as a percent of the fuel cost to account for lubricants and other consumables. The calculation of variable cost for the four alternatives considered is shown in table 2. The variable cost is also known as the "energy" cost of power. "Power" is a term that, in the electricity generation industry, includes both energy and capacity components.

Table 2 – Calculation of Variable Cost of Replacement Power

REFERENCE GENERATION TECHNOLOGY		High Speed Diesel	Combined Cycle	Low Speed Diesel	Coal Fired Steam Turbine
FUEL TYPE		Distillate Oil No. 2	Natural Gas	Residual Oil No. 6	Anthracite Coal
USUAL TRADE UNIT	unit	Barrel	Thousand Cubic Meters	Barrel	Metric Ton
HEAT CONTENT PER TRADE UNIT	Mbtu/unit	5.54	36.27	5.81	22.00
COST PER TRADE UNIT	$/unit	149.94	385.69	89.33	68.09
UNIT FUEL COST	$/Mbtu	27.09	10.63	15.37	3.10
HEAT RATE	btu/kwh	12,000.00	7,000.00	8,500.00	10,000.00
VARIABLE COST FUEL	$/MWh	325.04	74.44	130.62	30.95
VARIABLE OPERATION AND MAINTENANCE	% of fuel cost	5.0%	3.0%	5.0%	7.0%
VARIABLE OPERATION AND MAINTENANCE	$/MWh	16.25	2.23	6.53	2.17
TOTAL VARIABLE COST	$/MWh	341.30	76.67	137.15	33.12

2.6 Fixed Cost of Replacement Power

The fixed cost of power is the annual cost of salaries and other fixed operating expenses of the plant and the cost of amortizing the investment made on the plant.

Capital Cost

Unit EPC Cost

EPC is the estimated cost of engineering, procurement and construction involved in building the plant. The unit EPC is obtained by dividing the EPC cost by the installed capacity of the plant.

IDC Cost

The interest during construction represents the opportunity cost of capital disbursed during construction up to the time when the project starts operating. This cost is a function of the duration of construction, of the discount rate and also of the schedule of disbursements during construction. To simplify the analysis it is assumed that IDC can be approximated by the following formula:

$$IDC = 0.5 * EPC * P * i$$

where:
IDC: interest during construction in Million $
EPC: EPC in Million $
i: discount rate
P: construction period in years

Investment

The sum of the EPC and the IDC results in the present value of the investment at the time of commissioning of the project

Annual Capital Cost

The annual amortization of the investment over its economic life L is a value such that the accumulated present value of the string of L constant values is equal to the investment. This annual amortization is obtained by multiplying the investment by the Capital Recovery Factor (CRF). The CRF is given by the formula:

$$CRF = \frac{[(1+i)^L]*i}{[(1+i)^L]-1}$$

where:
CRF: Capital Recovery Factor
i: discount rate
L: economic life in years

Then:

Annual Capital Cost = Investment * CRF

The annual capital cost is an economic and cost accounting concept that does not represent a real annual disbursement. However, the CRF can also be used to calculate the annual cost of debt service on a loan used to finance the plant. This can be done by making the following replacements: a) Replace "Investment" by "Loan Amount", b) Replace "Economic Life" by "Loan Term" and c) Replace "Discount Rate" by "Loan Interest".

Fixed Operating Cost

This is the annual cost of salaries, administration, building maintenance and several other items that are not a function of the amount of energy produced by the plant. It can also be expressed as a percent of the annual capital cost.

Unit Annual Fixed Cost

The annual fixed cost is the sum of annual capital and operating cost divided by the installed capacity of the plant. Table 3 shows the calculation of unit fixed costs for the generation alternatives under consideration.

Table 3 – Calculation Unit Fixed Cost of Replacement Power

REFERENCE GENERATION TECHNOLOGY		High Speed Diesel	Combined Cycle	Low Speed Diesel	Coal Fired Steam Turbine
UNIT EPC	$/kW	400.00	800.00	800.00	1,500.00
CONSTRUCTION PERIOD	years	1.00	2.00	2.00	5.00
UNIT IDC	$/kW	20.00	80.00	80.00	375.00
UNIT CAPITAL COST	$/kW	421.00	882.00	882.00	1,880.00
ECONOMIC LIFE	years	15.00	25.00	15.00	30.00
CAPITAL RECOVERY FACTOR		0.13	0.11	0.13	0.11
UNIT ANNUAL CAPITAL COST	$/kW	55.35	97.17	115.96	199.43
FIXED OPERATION AND MAINTENANCE COST	% of EPC per Year	3.0%	3.0%	3.0%	3.0%
UNIT FIXED OPERATION AND MAINTENANCE COST	$/kW	12.00	24.00	24.00	45.00
UNIT ANNUAL FIXED COST	$/kW	67.35	121.17	139.96	244.43

2.7 Monomic Cost of Replacement Power

Generation projects contribute two types of services to an electric power system. One service is “energy supply” and the value of this service is captured by the variable cost of replacement power discussed above and commonly measured in $/MWh. The other service is “capacity supply” which means the contribution to the system ability to meet peak demand. The value of this service is captured by the fixed cost of replacement power discussed above and commonly measured in $/MW-year.

It is often more practical in economic analysis to use a single value that captures both energy and capacity components of value. This is called the “monomic (or one-part) value” and it is obtained by the following formula:

$$M = [(E * 8{,}760 * LF) + C] / (8{,}760 * LF)$$

Where:

M = Monomic value
E = Energy value
C= Capacity value
LF = Load Factor
8,760 = number of hours per year

This formula essentially spreads the fixed cost of one megawatt of capacity (required to meet peak demand) over the expected megawatt-hours of energy demand that are expected to be associated with that capacity during one year. That association of energy to capacity is captured by the “load factor” and is typically between 0.60 and 0.80 for most power systems. The value 0.70 was used in this approximation,

Table 4 shows the calculation of monomic value of the alternatives under consideration for a range of load factors. The values for a load factor of 70% are highlighted because that is approximately the load factor of the power systems under analysis.

Table 4 – Monomic Replacement Cost of Power

CAPACITY VALUE	$/kW-year	67.35	121.17	139.96	244.43
ENERGY VALUE	$/MWh	341.30	76.67	137.15	33.12
MONOMIC VALUE IN $/MWH (as a funtion of capacity factor)	Capacity Factor				
	10%	418.18	214.99	296.92	312.15
	20%	379.74	145.83	217.04	172.63
	30%	366.92	122.78	190.41	126.13
	40%	360.52	111.25	177.09	102.87
	50%	356.67	104.34	169.11	88.92
	60%	354.11	99.73	163.78	79.62
	70%	352.28	96.43	159.98	72.98
	80%	350.91	93.96	157.12	68.00

Tables 2 to 4 are extracted from page "POWER COST" of PEM.

2.8 Replacement Cost by Country

Once the monomic cost of power for each thermal generation option has been determined then there is a need to estimate what will be the proportion of each thermal option that would be used in each country if hydroelectric power were not available. Some clues can be obtained from the expected generation expansion plans discussed in item 2.2.This will be explained below and the results are shown in Table 5.

Table 5 – Power Replacement Cost by Country

Generation Technology	Cost	Percent Use of Generation Technology			
	$/MWh	LAOS	THAILAND	CAMBODIA	VIETNAM
High or Medium Speed Diesel Units using Diesel Oil	352.3	30.0%		50.0%	
Low Speed Diesel Units Using Bunker Oil	160.0	20.0%			
Combined Cycle Units using Natural Gas	96.4		60.0%		
Steam Turbine Units using Coal	73.0	50.0%	40.0%	50.0%	100.0%
Monomic Replacement Cost of Power ($/mwh) at 70% System Load Factor		174.2	87.1	212.6	73.0

The clearest case is Vietnam. It seems reasonable to expect that, if nuclear or hydroelectric power were not viable options then Vietnam would pursue a fully coal fired generation expansion and the replacement cost of that power, accounting for all costs including escalation of coal prices is 73 $/MWh (or 7.3 Cents/kWh).

Thailand is a little more complex because it unclear how much of future demands can actually be covered by natural gas which probably would be the preferred option since it is both cleaner and cheaper power. It has been assumed than in the absence of hydro about 60% of the incremental demand would be covered by combined cycle machines using natural gas and the rest with coal fired steam plants. This results in a replacement cost of power of 87.1 $/MWh (or 8.7 Cents/kWh).

Cambodia currently relies almost entirely on oil fired generation and reports plans for coal fired generation. Coal would therefore appear like a reasonable alternative but its current reliance on small diesel generators makes it unlikely that the transmission system would be capable of immediately providing coal fired power everywhere. Thus, a balanced mix of coal fired steam and high speed diesel has been assumed as a reasonable option over the next 20 years if hydroelectric power was not available. This results in a replacement cost of power of 212.6 $/MWh (or 21.3 Cents/kWh).

Laos is the most difficult case to assess since there are no plans or expectation for thermal power supply. However, Laos does have a reasonable transmission network and thus it could be expected that, in the absence of hydro, much of the load could be supplied with coal fired generation or, at least, low speed diesel generators and only isolated parts would still rely on high speed diesel. A reasonable combination of these thermal generation options would result in a replacement cost of power of 174.2 $/MWh (or 17.4 Cents/kWh).

3 PROJECT ANALYSIS

The economic analysis involves several steps that will be discussed in this chapter and constitute the analysis that is carried out in page "ANALYSIS" of PEM.

3.1 Key Project Inputs of the Economic Analysis

From the hydropower database available at MRC the following information was extracted for each project relevant to the economic analysis:

1. Code and name of each project
2. Host country and start date
3. Current (2008) budget and construction period
4. Installed Capacity
5. Mean Annual Energy Production
6. Intended distribution of the power production among Laos, Cambodia, Thailand and Vietnam

In addition, the analysis uses the power replacement cost estimated for each country and the economic discount rate adopted. These values can be modified in page "SUMMARY" of PEM.

3.2 Project Cost

The first step of the analysis involves the calculation of the annual cost of the project. This calculation follows the same steps described in item 2.6 for the computation of fixed costs of thermal generation. In this case the capital cost is calculated using a project life of 50 years which is the accepted economic life of a hydropower project. The annual fixed operation and maintenance cost is conservatively estimated at 1% of the EPC cost. The total annual cost of the project is then calculated by adding annual capital and operating costs. The variable cost of hydroelectric power is negligible and has been ignored.

3.3 Economic Cost Recovery Price

The cost recovery price of the energy from each project is the annual project cost divided by the mean annual energy production.

3.4 Financial Analysis Parameters

Following the calculation of Cost Recovery Price in page "ANALYSIS" of PEM there are several columns dedicated to financial analysis. These columns are not relevant to the economic analysis but are included to provide information for other aspects of the analysis of river basin development. The objective is to use assumptions on the financial structure of the development of the projects to estimate the margin that could be available to the host country both during and after the payment of the project debt.

3.5 Annual Power Supply and Export

Using the intended distribution of power to the different countries, two sets of values are calculated. One is the annual power production intended for use in each country. The other is the annual power export from the host country to other countries.

3.6 Annual Gross Power Supply Benefits

The annual gross benefit of the project from power supply is calculated for each country by the product of the power supplied by the replacement cost of power in each country.

3.7 Annual Gross Export Benefit

When part of the project production is destined to another country the gross annual export benefit is calculated at a proxy value for the actual trade price. This proxy is obtained as a discount over the replacement cost of power at the importing country and the discount is an input in page “SUMMARY” of PEM. This benefit is only applicable to the host country.

3.8 Net Annual Economic Benefit

The net annual economic benefit of the project is calculated differently for the host country and for the importing countries. For the host country the net annual benefit is the sum of the benefits from power supply and from export less the annual cost of the project. For importing countries the net annual benefit is the difference between the replacement value of imported power and the cost of import calculated at the proxy trade price.

3.9 Annual Financial Outlook

While not relevant to the economic analysis, two other sets of values are prepared for each project and country. These sets capture the estimated cash flow of the project to the host country during and after the loan repayment term. These values are calculated using assumption contained in page “SUMMARY” of PEM related to the project financial structure. This information is useful to evaluate the likelihood that these projects will actually be developed and will be discussed in a separate document.

4 SCENARIO ANALYSIS AND ASSESSMENT OF UNCERTAINTY

4.1 Scenario Pages of PEM

The Power Evaluation Model PEM contains one page for each scenario and these are labeled S1 to S9 for the nine scenarios currently under analysis. Each page contains a list of all the projects and a switch of 0 or 1 for each project. If the switch is set to 1 the project is included in that scenario.

Each scenario page has all the columns corresponding to the items 3.5 to 3.9 described in chapter 3 and calculated in the page "ANALYSIS" of PEM. For each project the values in the page "ANALYSIS" are multiplied by the switch (0 or 1) so that these values are included or not in the specific scenario.

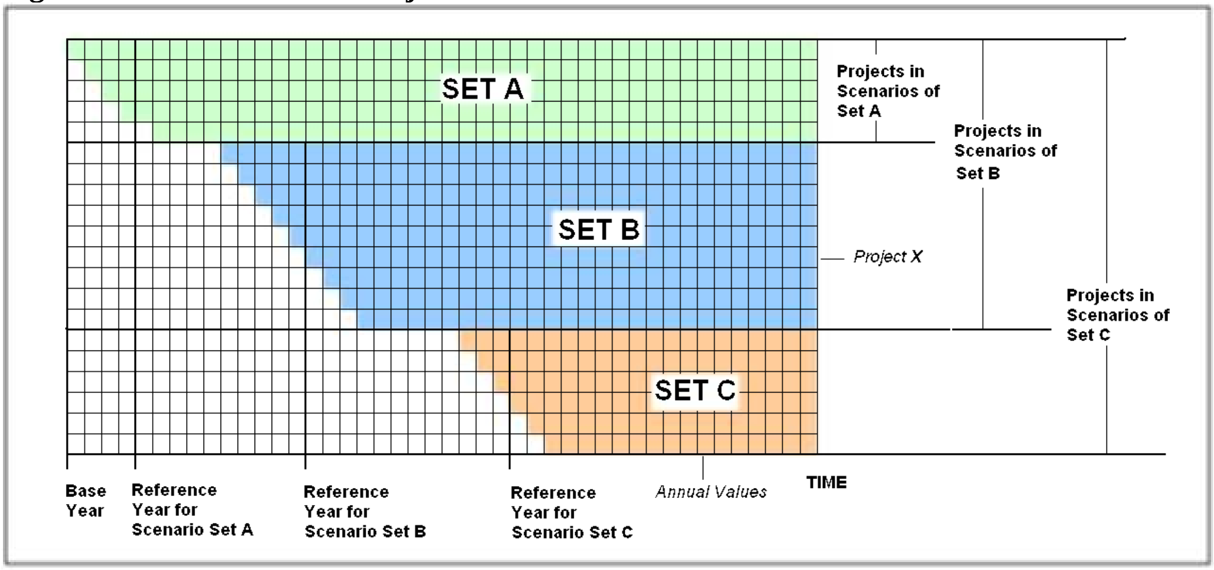
For each column, the corresponding values for all projects are added up in the last line of each scenario page. These aggregate values are then ready to be copied into the "DISCOUNTING" page of PEM.

4.2 Discounting Annual Values

The aggregate of all project values for each scenario is brought to the DISCOUNTING page.

These values prepared in the SCENARIO pages correspond to the aggregate of the annual values for each project but these annual aggregate values are not directly comparable among scenarios because the project values are offset in time depending on the particular scenario, as illustrated in Figure 1.

Figure 1 – Time Offset for Projects in Different Scenario Sets



Thus, before the scenarios can be compared the values of the incremental projects between different sets of scenarios need to be discounted to the base year. This adjustment is carried out in the DISCOUNT page of PEM.

4.3 Creating Lifetime Values

Once the aggregated annual values for each scenario have been discounted to the base year, the lifetime benefits can be calculated dividing by the CRF for a lifetime of 50 years and the selected discount rate.

The baseline values are then subtracted from the final results for each scenario which are then copied to the SUMMARY page as the detailed output of the analysis as shown in Table 6 and further summarized in Table 7.

Table 6 – Scenario Results relative to Baseline

		POWER SUPPLY GWH					POWER EXPORT GWH					INVESTMENT M$				
SCENARIO	CODE	LA	TH	CA	VI	TOTAL	LA	TH	CA	VI	TOTAL	LA	TH	CA	VI	TOTAL
2015-UMD	S2	0	0	0	0	**0**	0	0	0	0	**0**	0	0	0	0	**0**
2015-DF	S3	2,479	9,776	23	8,317	**20,595**	10,892	0	0	0	**10,892**	2,330	0	4	1,324	**3,658**
2030-20Y	S4	19,253	58,291	3,677	31,399	**112,620**	62,132	0	19,384	0	**81,516**	11,344	0	4,501	1,473	**17,317**
2030-20Y- W/O MD	S5	7,878	23,804	1,703	12,688	**46,073**	26,698	0	1,618	0	**28,317**	5,442	0	491	1,473	**7,405**
2030-20Y-W/O LMD	S6.1	11,128	48,155	1,703	17,581	**78,567**	55,943	0	1,618	0	**57,562**	9,364	0	491	1,473	**11,328**
2030-20Y-W/O TMD	S6.2	14,504	49,288	3,677	31,399	**98,868**	53,128	0	19,384	0	**72,513**	9,454	0	4,501	1,473	**15,427**
2030-20Y-Flood	S7	19,253	58,291	3,677	31,399	**112,620**	62,132	0	19,384	0	**81,516**	11,344	0	4,501	1,473	**17,317**
2060-LTD	S8	25,919	58,462	7,528	32,302	**124,211**	63,205	0	19,384	0	**82,589**	11,465	0	4,622	1,473	**17,560**
2060-VHD	S9	28,146	58,462	8,027	32,406	**127,041**	63,310	0	19,384	0	**82,694**	11,531	0	4,641	1,473	**17,645**
		GROSS BENEFIT FROM POWER SUPPLY M$					BENEFIT FROM EXPORT M$					NET ECONOMIC BENEFIT M$				
SCENARIO	CODE	LA	TH	CA	VI	TOTAL	LA	TH	CA	VI	TOTAL	LA	TH	CA	VI	TOTAL
2015-UMD	S2	0	0	0	0	**0**	0	0	0	0	**0**	0	0	0	0	**0**
2015-DF	S3	3,216	6,339	37	4,521	**14,113**	5,922	0	0	0	**5,922**	6,619	951	5	2,584	**10,159**
2030-20Y	S4	14,384	22,484	3,006	10,961	**50,834**	20,230	0	4,777	0	**25,007**	22,358	3,373	2,762	3,682	**32,175**
2030-20Y- W/O MD	S5	6,811	11,007	1,402	5,741	**24,961**	10,431	0	384	0	**10,815**	11,358	1,651	1,047	2,899	**16,955**
2030-20Y-W/O LMD	S6.1	8,975	19,111	1,402	7,106	**36,593**	18,479	0	384	0	**18,863**	17,336	2,867	1,047	3,104	**24,353**
2030-20Y-W/O TMD	S6.2	11,222	19,488	3,006	10,961	**44,677**	17,683	0	4,777	0	**22,460**	18,690	2,923	2,762	3,682	**28,057**
2030-20Y-Flood	S7	14,384	22,484	3,006	10,961	**50,834**	20,230	0	4,777	0	**25,007**	22,358	3,373	2,762	3,682	**32,175**
2060-LTD	S8	14,793	22,489	3,295	10,984	**51,561**	20,254	0	4,777	0	**25,031**	22,661	3,373	2,921	3,686	**32,640**
2060-VHD	S9	14,930	22,489	3,333	10,987	**51,738**	20,256	0	4,777	0	**25,033**	22,729	3,373	2,937	3,686	**32,725**

Table 7 – Summary of Results

SCENARIO	CODE	POWER SUPPLY GWH	POWER EXPORT GWH	CAPITAL INVEST. M$	NET BENEFIT M$	DISTRIBUTION OF NET BENEFITS (*)			
						LA	TH	CA	VI
2015-UMD	S2	0	0	0	0	0%	0%	0%	0%
2015-DF	S3	20,595	10,892	3,658	10,159	65%	9%	0%	25%
2030-20Y	S4	112,620	81,516	17,317	32,175	69%	10%	9%	11%
2030-20Y- W/O MD	S5	46,073	28,317	7,405	16,955	67%	10%	6%	17%
2030-20Y-W/O LMD	S6.1	78,567	57,562	11,328	24,353	71%	12%	4%	13%
2030-20Y-W/O TMD	S6.2	98,868	72,513	15,427	28,057	67%	10%	10%	13%
2030-20Y-Flood	S7	112,620	81,516	17,317	32,175	69%	10%	9%	11%
2060-LTD	S8	124,211	82,589	17,560	32,640	69%	10%	9%	11%
2060-VHD	S9	127,041	82,694	17,645	32,725	69%	10%	9%	11%

(*) Assuming all costs borne by host country and export price set at 85% of replacememt cost of importing country

4.4 Critical Review of Scenarios

From Table 7 it is clear that all scenarios look attractive in terms of power economics since net power benefits exceed investment requirements by a healthy margin. Scenarios 1 to 3 are considered firm as they involve projects that are either in operation or under active development. All other scenarios are subject to change since the projects are in different stages of analysis and some may either be abandoned or substantially modified. It is therefore relevant to conduct a cursory examination of Scenario 4, the base case in a set of scenarios of possible projects to be developed in the next 20 years.

This could of course be subject to different assumptions but before examining those assumptions it is necessary to first evaluate the realism of the scenarios themselves, particularly Scenario 4 which involves projects not yet under development and expected to develop within the next 20 years.

4.5 Uncertainty of Project Development due to Demand Constraints

There is no doubt that any exports of hydropower to Thailand of Vietnam can be easily absorbed by the demand of those large power systems. The situation is different for the small systems of Laos and Cambodia and it must be established that the power supply targeted to Laos and Cambodia from new hydroelectric projects is compatible with the incremental demand and the expected replacement of thermal generation in those countries.

In this context it is more relevant to balance demand and supply of electric energy rather than capacity because hydroelectric capacity is rarely driven by peak system demand but by the need to capture the energy of wet season flows. Thus, it would be perfectly normal if incremental capacity exceeded incremental peak demand.

The growth of electricity demand in small systems tends to be quite volatile and highly dependent on economic conditions and on electrification development. For example, during this decade the annual growth of electricity demand in Cambodia had a high of 38%, a low of -0.3% and mean of 14%. As a reference it is reasonable to expect that the average annual rate of demand growth in Laos and Cambodia in the next 20 years will be well above 5%. That means a minimum of about 3,800 GWh of new energy demand in Laos and 2,600 GWh of new demand in Cambodia. These values are well above the expected supply of new projects in Scenario 3 which assumes 2,500 GWh of new hydropower for Laos and almost nothing for Cambodia.

4.6 Uncertainty of Project Development due to Financial Constraints

The next aspect to consider is whether the projects scheduled for development in the next 20 years will indeed be attractive to develop from a financial perspective. This is a completely different analysis that that involved in the analysis of economic benefits, for several reasons.

Differences between Economic and Financial Analysis

The economic analysis compares the economic gross benefits of power against the economic cost producing it. From an economic perspective, power benefits are based on the replacement cost of that power to the economies of the countries involved whereas from a financial perspective the benefit is the expected revenue stream of the projects which results from electricity tariffs and export prices. Furthermore, from an economic perspective both benefits and costs are measured over the project lifetime of at least 50 years whereas from a financial perspective the revenue stream must be sufficient to pay debt service and provide acceptable return on equity over a loan period that rarely exceeds 20 years.

Annual Financial Cost during Loan Repayment

The debt service and return on equity added to the annual operating costs of a generation project determine the annual financial cost of the project and when divided by the mean annual energy production it results in the financial cost of power from the project during the loan repayment term.

Annual Revenues

Domestic Sales

The project revenues consist of the sale of power at what, for simplicity, we shall assume to be a monomic (or one-part) tariff that includes both capacity and energy. The portion of the project energy that is targeted for the host country will receive revenues based on the tariff that is applicable to generating plants in that market. The portion that is exported will receive revenues based on a negotiated trade price. All these values are difficult to forecast into the future, more so since none of the systems under consideration have adopted uniform wholesale tariffs. Therefore, the analysis must be based on assumptions, as follows.

In the systems of Thailand and Vietnam, with significant industrial loads, it can be safely assumed that average retail tariffs, which includes the cost of transmission and distribution, will gravitate towards cost of service and therefore the domestic tariff in these countries will be assumed to equal replacement cost, 5.2 Cents/kWh for Thailand and 7.2 Cents/kWh for Vietnam.

A cursory research indicates that retail tariffs in Laos are approximately 6 Cents/kWh for industrial consumers, 8 Cents/kWh for commercial consumers and between 1 and 7 Cents/kWh for residential consumers. This could put the average retail tariff at some 6 Cents/kWh. While the proportion of distribution and transmission over generation costs in tariffs can vary greatly, it could be expected that at least half of the collection, or 3 Cents/kWh could be dedicated to pay for generation. This level will be assumed reasonably to be within the ability to pay for generation by average electricity customers in Laos and Cambodia.

Trade Price

The same proxy trade price used for the economic analysis will be assumed. This is a price that carries a discount over the replacement cost of the importing country.

Rate of Return on Equity

The difference between annual revenues and costs is the net financial result before taxes and when divided by the portion of the investment that was contributed by equity holders it represents a very simplified internal rate of return on equity that is useful for the purpose of comparing the relative likelihood of development from a financial perspective.

Calibration

Before applying the methodology described above to the new projects contemplated in Scenario 4, it is useful to establish some benchmark based on the financial performance that this methodology would assign to committed projects in the "Definite Future" or Scenario 3. This analysis is shown in Table 8.

Table 8 – Financial Performance of Committed Projects

PROJECT NAME		PROJECTS				CAPACITY MW				RETURN ON EQUITY %				PROJECTS ROE > 10%				CAPACITY ROE > 10%			
		LA	TH	CA	VI	LA	TH	CA	VI	LA	TH	CA	VI	LA	TH	CA	VI	LA	TH	CA	VI
L004	Xeset 1	1	0	0	0	45	0	0	0	-11%	0%	0%	0%	0	0	0	0	0	0	0	0
L008	Nam Mang 3	1	0	0	0	40	0	0	0	-17%	0%	0%	0%	0	0	0	0	0	0	0	0
L011	Nam Theun 2	1	0	0	0	1,075	0	0	0	79%	0%	0%	0%	1	0	0	0	1,075	0	0	0
L012	Xekaman 3	1	0	0	0	250	0	0	0	25%	0%	0%	0%	1	0	0	0	250	0	0	0
L013	Xeset 2	1	0	0	0	76	0	0	0	12%	0%	0%	0%	1	0	0	0	76	0	0	0
L014	Nam Ngum 2	1	0	0	0	615	0	0	0	27%	0%	0%	0%	1	0	0	0	615	0	0	0
L015	Nam Lik 2	1	0	0	0	100	0	0	0	-5%	0%	0%	0%	0	0	0	0	0	0	0	0
L016	Nam Ngum 5	1	0	0	0	120	0	0	0	-8%	0%	0%	0%	0	0	0	0	0	0	0	0
L017	Xekaman 1	1	0	0	0	290	0	0	0	43%	0%	0%	0%	1	0	0	0	290	0	0	0
L018	Xekaman-Sanxay	1	0	0	0	32	0	0	0	-4%	0%	0%	0%	0	0	0	0	0	0	0	0
L019	Theun-Hinboun expansion	1	0	0	0	222	0	0	0	133%	0%	0%	0%	1	0	0	0	222	0	0	0
L020	Theun-Hinboun exp. (NG8)	1	0	0	0	60	0	0	0	-24%	0%	0%	0%	0	0	0	0	0	0	0	0
C001	O Chum 2	0	0	1	0	0	0	1	0	0%	0%	-43%	0%	0	0	0	0	0	0	0	0
V002	Plei Krong	0	0	0	1	0	0	0	100	0%	0%	0%	30%	0	0	0	1	0	0	0	100
V004	Se San 3	0	0	0	1	0	0	0	260	0%	0%	0%	128%	0	0	0	1	0	0	0	260
V005	Se San 3A	0	0	0	1	0	0	0	96	0%	0%	0%	113%	0	0	0	1	0	0	0	96
V006	Se San 4	0	0	0	1	0	0	0	360	0%	0%	0%	104%	0	0	0	1	0	0	0	360
V007	Se San 4A	0	0	0	1	0	0	0	0	0%	0%	0%	-52%	0	0	0	0	0	0	0	0
V009	Buon Tua Srah	0	0	0	1	0	0	0	86	0%	0%	0%	52%	0	0	0	1	0	0	0	86
V010	Buon Kuop	0	0	0	1	0	0	0	280	0%	0%	0%	122%	0	0	0	1	0	0	0	280
V011	Dray Hinh 2	0	0	0	1	0	0	0	16	0%	0%	0%	149%	0	0	0	1	0	0	0	16
V012	Sre Pok 3	0	0	0	1	0	0	0	220	0%	0%	0%	95%	0	0	0	1	0	0	0	220
V013	Sre Pok 4	0	0	0	1	0	0	0	70	0%	0%	0%	204%	0	0	0	1	0	0	0	70
V015	Sre Pok 4A	0	0	0	1	0	0	0	64	0%	0%	0%	35%	0	0	0	1	0	0	0	64
TOTAL		12	0	1	11	2,925	0	1	1,552	250%	0%	-43%	980%	6	0	0	10	2,528	0	0	1,552
AVERAGE						244		1	141	21%		-43%	89%					421			155

Using the methodology described above, the committed projects all show either a rate of return above 10% (black font in Table 8), or else a negative value (red font). The average rate of return is 49.5%. The proportion of projects with rate of return above 10% is 67% and the proportion of installed capacity in projects with rate of return above 10% is 91%.

Financial Performance of New Projects in Scenario 4

The analysis is now applied to the new projects in Scenario 4 and the results are shown in Table 9.

The average rate of return of all 48 new projects is only 7% compared to 49.5% above. Only 46% of the projects show rates of return above 10% compared to 67% above. The proportion of installed capacity in projects with rate of return above 10% is 70% compared to 91% above.

These results suggest that a considerable number of projects in Scenario 4 “Foreseeable Future” may not materialize if financial requirements remain as in the present. If the relative proportions of “attractive” over total capacity are compared against the new projects in the Definite Future scenario 3, (70% against 91%) then it can be expected that somewhere in the order of 20% of the installed capacity in Scenario 4 will be difficult to finance.

The result of these comparisons between the Foreseeable Future (scenario 4) and the Definite Future (scenario 3) is not unexpected. Within the same financial context it is natural that projects with better financial outlook will be developed first and that projects in progressively more distant scenarios, will appear less financially attractive when measured on the same financial terms. Thus, this analysis should not be viewed as expressing uncertainty over the development of projects but rather over their likely development in the next 20 years.

Table 9 – Financial Performance of Non-Committed Projects

PROJECT NAME					CAPACITY MW			Active Storage	Seasonal Transfer	RETURN ON EQUITY									Active Storage	Seasonal Transfer
		LA	CA	VI	LA	CA	VI	mcm	mcm	LA	CA	VI	LA	CA	VI	LA	CA	VI	mcm	mcm
L021	Nam Ngum 3	1			440			979	979	28%			1			440			979	979
L022	Nam Theun1	1			523			2,549	2.549	12%			1			523			2,549	2,549
L023	NamNgiep 1	1			260			1,192	1.192	26%			1			260			1,192	1,192
L024	Nam Ngiep-regulating dam	1			17			5	0	-4%										
L025	Nam Tha 1	1			168			676	0	-17%										
L027	Xepian-Xenamnoy	1			390			885	885	4%										
L028	Xe Katam	1			61			115	115	62%			1			61			115	115
L029	Xekong 4	1			300			3.100	3.100	4%										
L030	Nam Kong 1	1			75			505	505	77%			1			75			505	505
L031	Xe Kong 3up	1			145			95	0	66%			1			145			95	0
L032	Xe Kong 3d	1			91			168	0	57%			1			91			168	0
L033	Xe Kong 5	1			248			1.356	1.356	6%										
L034	Don sahong mainstream	1			360			115	0	33%			1			360			115	0
L035	Nam Ou 1	1			180			10	0	12%			1			180			10	0
L036	Nam Ou 2	1			90			8	0	-15%										
L037	Nam Ou 3	1			300			14	0	22%			1			300			14	0
L038	Nam Ou 4	1			75			9	0	9%										
L039	Nam Ou 5	1			108			11	0	2%										
L040	Nam Ou 6	1			210			363	0	-2%										
L041	Nam Ou 7	1			180			1,134	1.134	-21%										
L042	Nam Lik 1	1			54			7	0	-16%										
L043	Nam San 3	1			48			122	122	-12%										
L044	Nam Pha	1			147			2.738	2.738	-22%										
L045	Nam suang 1	1			40			88	0	-19%										
L046	Nam Suang 2	1			134			2.015	2.015	-22%										
L048	Nam Beng	1			30			98	0	-21%										
L052	Pakbeng mainstream	1			1.230			442	0	18%			1			1.230			442	0
L053	Luangprabang mainstream	1			1.410			734	0	30%			1			1.410			734	0
L054	Xayabuly mainstream	1			1.260			225	0	30%			1			1.260			225	0
L055	Paklay mainstream	1			1.320			384	0	18%			1			1.320			384	0
L056	Sanakham mainstream	1			1.200			106	0	22%			1			1.200			106	0
L057	Sangthong-Pakchom mainstream	1			1.079			12	0	11%			1			1.079			12	0
L058	Ban Kum mainstream	1			1.872			0	0	0%										
L059	Latsua mainstream	1			800			0	0	-16%										
L063	Xe Kaman 4A	1			96			17	0	15%			1			96			17	0
L064	Xe Kaman 4B	1			74			21	0	19%			1			74			21	0
L092	Xe Set 3	1			20			4	0	-11%										
L096	Nam Phak	1			75			35	35	-10%										
L098	Houay Lamphan	1			60			128	128	-27%										
C002	Lower Se San2 + Lower Sre Pok 2		1			480		379	0		24%			1			480		379	0
C003	Battambang 1		1			24		1,040	1,040		-27%									
C004	Battambang 2		1			22		110	110		-33%									
C005	Sambor mainstream		1			3,300		2.000	0		15%			1			3,300		2.000	0
C006	Stung Treng mainstream		1			980		70	0		-18%									
C007	Pursat 1		1			100		690	690		-19%									
C008	Pursat 2		1			10		295	295		-44%									
V001	Upper Kontum			1			250	123	123			73%			1			250	123	123
V008	Duc Xuyen			1			49	413	413			32%			1			49	413	413
TOTAL FOR ALL NEW PROJECTS		39	7	2	15,170	4,916	299	25,583	19,523	351%	-103%	105%	18	2	2	10,104	3,780	299	10,598	5,876
AVERAGE					389	702	150	533	407	9%	-15%	52%				561		150	482	267
SUBTOTAL FOR MAINSTREAM PROJECTS		9	2	0	10,531	4,280	0	4,088	0	147%	-4%	0%	7	1	0	7.859	3.300	0	4.018	0
AVERAGE					1,170	2,140		372	0	16%	-2%					1,123			502	0
SUBTOTAL FOR NEW TRIBUTARY PROJECTS		30	5	2	4,639	636	299	21,495	19,523	[illegible]	[illegible]	[illegible]	11	1	2	2,245	480	299	6.580	5.876
AVERAGE					155	127	150	581	528	7%	-20%	52%				204		150	470	420

Relative Performance of Mainstream and Tributary Projects

It is also interesting to compare the financial performance of mainstream projects against those in tributary rivers. This analysis is also shown in Table 9. Financial performance is above the threshold return on equity of 10% for 8 out of 11 mainstream projects corresponding to 75% of their capacity. The average financial performance of mainstream projects is 13%. The same analysis for projects in tributary rivers shows acceptable return for 14 out of 37 projects corresponding to 54% of their capacity. The average financial performance of projects in tributary rivers is 5.7%.

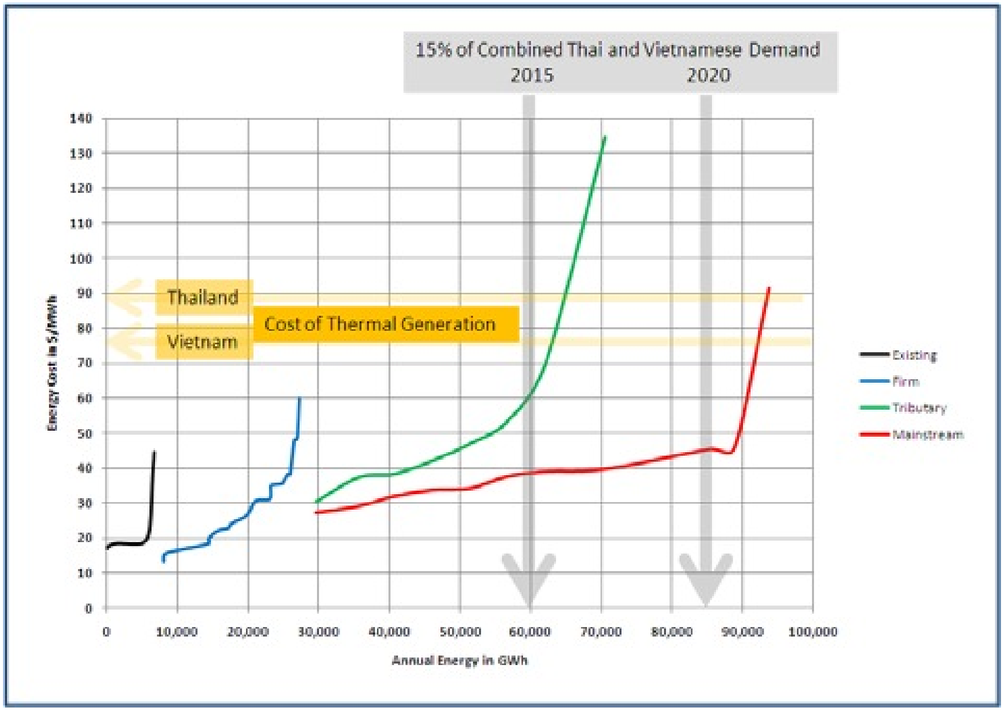
A better way to visualize the relative interest that may exist bewteen mainstream and tributary projects is by means of a concept known as "power supply curves". These curves are developed by first ranking projects in order of increasing energy costs and then aggragting their annual energy potential. The result is a plot that shows how much anual energy is available below a given energy cost level.

When compared against likely import targets by Thailand and Vietnam and also against the replacement cost of power in those countries, as shown in Figure 2, it is possible to obtain a consolidated picture of both the potential and the interest of importing power from mainstream and tributary projects by these two major power importing countries.

Figure 2 shows the supply curves for four groups of projects. Those that are in operation, those that are under construction or firm development and the mainstream and tributary projects not yet committed. The following observations are made:

- Hydropower projects in operation in the LMB are all in tributary rivers and currently produce approximatley 6,500 GWh (6,5 million MWh) per year. The energy cost of existing projects is not very accurately defined as some of these are fairly old but it is estimated that, if they had to be built today, most of that power would cost between 15 and 20 $/MWh to produce.
- Projects under development in tributary rivers of the LMB could add approximately 20,000 GWh per year and their energy cost is in the range of 15 to 60 $/MWh compared to the range of 73 to 87 $/MWh that corresponds to the anticipated domestic cost of thermal generation in Vietnam and Thailand.
- Undecided projects in tributary rivers have a potential for another 40,000 GWh per year but only about 3/4 of that energy could be produced under 70 $/MWh so the rest may not be attractive for export. Mainstream projects, on the other hand, have a potential to contribute some 65,000 GWh per year, most of it under 70 $/MWh.

Figure 2 - Supply Curves for Mainstream and Tributary Projects



4.7 Uncertainty of Seasonal Flow Regulation due to Project Development

One benefit associated with hydropower reservoirs is the regulation of flow which can be useful for agriculture, navigation and other uses. This storage, when sufficiently large, results in transfer of water from wet to dry season resulting in what has been called “new water” available for agriculture.

Table 9 includes information to assess the uncertainty of the impact of hydropower project storage in terms of its ability to transfer water from the wet season to the dry season. The seasonal transfer column in Table 9 only includes the active storage volume when that volume is deemed capable of storing at least 60 days of water inflow at the mean annual flow. Storage with a lesser regulation effect are assumed not useful for irrigation purposes.

New projects in Scenario 4 will contribute 19,523 MCM of useful seasonal water transfer, all of it in projects in tributary rivers. This transfer drops to 5,876 MCM if only those projects with acceptable financial performance are counted indicating that the most promising projects in terms of storage are also the less financially attractive.

4.8 Uncertainty of Seasonal Flow Regulation due to Reservoir Operation Policies

The analysis of seasonal water transfer carried out so far assumes that all the active storage of all projects will be used each year. In other words, assumes that the reservoir will all be drawn to their lowest operating level during each dry season and refilled to their maximum operating level during each wet season. The difference between these maximum and minimum levels is the operating range of the reservoir.

However, hydropower reservoirs are not necessarily operated through their entire range every year. The objective of a hydropower dam is not only to store water but, more importantly, to develop a differential elevation (head) upstream and downstream of the dam. The annual energy produced is directly proportional to both the volume of water passed through the turbines and the head at which it passed. Thus, there is a trade-off between keeping the reservoir high and risking spill of water or capturing as much water as possible but loosing head as a result of lower reservoir elevations.

If the operating range is small compared to the total head then it is more likely that the reservoir will be used through its entire range because the loss of head will be small relative to the additional water captured by the turbines. If the operating range is a large fraction of the total head it is very unlikely that it will be used fully if energy production is the objective.

While an exact determination would require specific analysis of each reservoir it is prudent to assume that no more than half the active storage will be used during normal hydrologic years. Thus, the total transfer of water from new projects in scenario 4 can be estimated as approximately 9,250 MCM of which 2,950 MCM correspond to projects very likely to be developed in the next 20 years.

4.9 Project Interdependency Issues

The analysis of uncertainty has been performed taking each project in isolation and not considering the impact of one project on the projects downstream. The conclusions of the uncertainty on seasonal water transfer highlight the significance of project interdependency since it is indeed quite possible that projects that appear less attractive in isolation can be credited with substantial contribution to other projects.

However, there is no information on the extent to which the energy potential of any specific project is dependent on the regulation provided by upstream projects. A thorough analysis would involve a recalculation of energy potential of each project with and without each project upstream of it in order to establish an interdependence matrix that could then be used to revise the financial performance analysis.

5 IMPACTS ON LOCAL LABOR

5.1 Scope of Analysis

The impact of hydropower on the labor market of a country has several different components. One is the direct job creation resulting from the construction activities and from the operation and maintenance of the projects. Another is the creation of skilled workers that can not only reduce dependence from foreign personnel but can themselves provide services in the hydropower development of other countries. Finally there is the impact of export revenue that, in a developing economy, can be a crucial source of capital for accelerating industrialization of the country.

5.2 Direct Job Creation

The development and operation of a hydroelectric projects is labor intensive. Approximately one half of the construction budget is in civil works of which 80% would be spent in local labor. The other half of the budget corresponds to electrical and mechanical equipment of which there could be a small component of local labor during the installation phase.

During the operation phase, approximately 70% of the annual operation and maintenance budget will be spent on local wages.

In Table 10 an estimate is shown of the likely value of local wages that will be generated by the new hydropower projects developed in the 2030-20y scenario

Table 10 – Local Wages Generated by Hydroelectric Projects

CONSTRUCTION PHASE						
			TOTAL LABOR		LOCAL LABOR	
	%	M$	%	M$	%	M$
Investment		35,043				
Construction Budget	80%	28,034				
Civil Works	50%	14,017	70%	9,812	80%	7,850
Equipment	50%	14,017	70%	9,812	5%	491
Estimated Local Wages during Construction						8,340
OPERATION PHASE						
Annual Operation and Maintenance Budget				M$/year	1%	280
Local Labor Componente of Operation and Maintenance Budget				M$/year	70%	196
Present Value of Local Labor over 50 year Project Life				M$		1,946
TOTAL PRESENT VALUE OF WAGES GENERATED BY PROJECTS				M$		10,286

From this table it is concluded that the present value of local wages is 37% of the construction cost or 29% of the total investment, which includes financing costs during development.

6 SENSITIVITY OF POWER BENEFIT DISTRIBUTION

6.1 Objective of the Sensitivity Analysis

The analysis of scenarios described in Chapter 4 of this report shows the portion of net economic benefits from power that could accrue to Laos, Cambodia, Thailand and Vietnam under each of the scenarios considered. That distribtion is based on two key assumptions that may differ considerably from project to project and could have a significant impact on how economic benefits get distributed among countries.

The first assumption is that the host country, that is, the country where the project is located, will be the project owner and therefore will have all the burden of cost including equity, debt and operating expense. The second assumption is that the importing country will pay a price equal to 85% of its domestic cost of thermal generation.

The objective of this chapter is to describe the different consequences of departure from the two assumptions since the viability of many projects may require very different cost sharing structures and pricing agreements between the countries interested in their development.

6.2 Alternative Cost Structure

In addition to the base case assumption it would seem reasonable that many projects may be structured as a cost sharing between the host and the importer and, very likely, this sharing will be in proportion to the quantities of energy expected to be taken by each party.

6.3 Alternative Trade Price

The price at which export-import will take place will probably be different for each project because it depends on very specific conditions. First, it will depend on the actual cost of alternative power of the buyer which may or may not be well represented by the system wide replacement cost forecasted for Thailand or Vietnam. Second, it will depend on the actual cost of energy from the project which is, of course, different in each case. Finally, it will depend on the requirements of the lender which may ask for a specific debt coverage ratio and therefore influence the terms of any power purchase agreement.

6.4 Sensitivity Analysis

The effect of different cost sharing and trade price conditions upon the distribution of net economic benefits from power is illustrated in Figure 3. The figure shows the net economic benefit accruing to each country under different conditions of cost sharing and trade price for projects in the 20 year development scenario ending in 2030. The benefits are shown separately for tributary and mainstream projects.

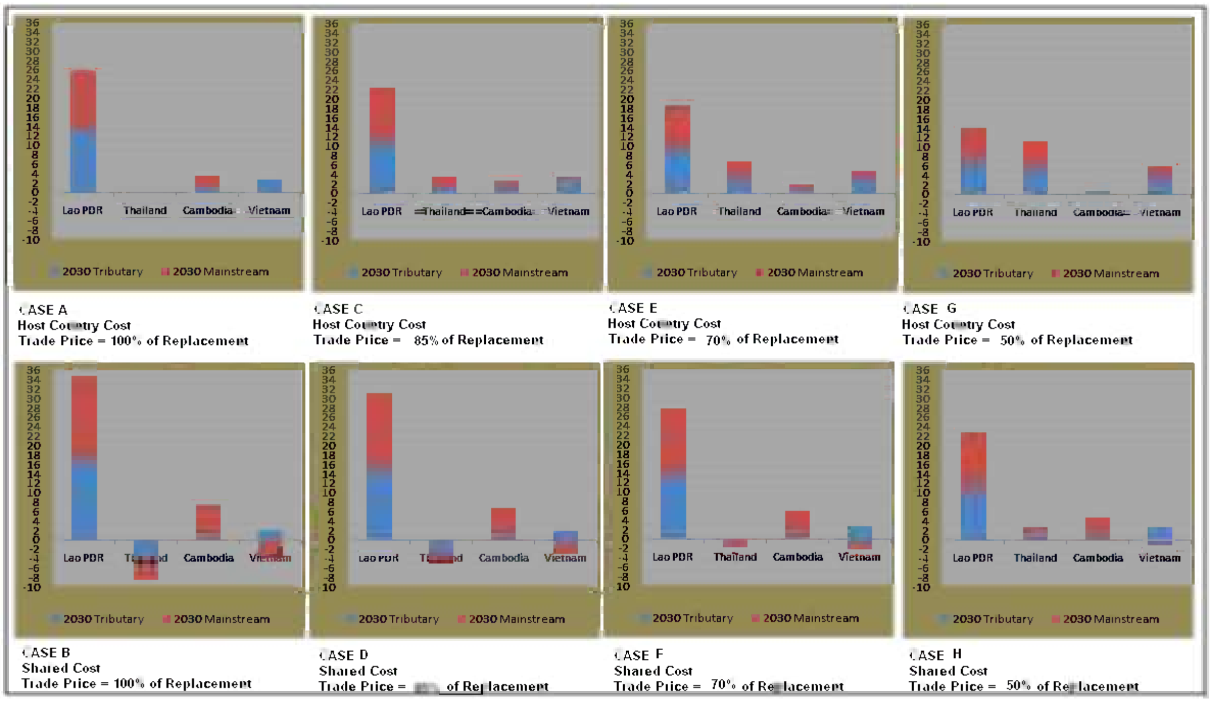
The following observations are made with reference to Figure 3

Cases A and B: Very High Trade Price

Cases A and B show an extreme situation in which the trade price would be equal to the replacement cost of the importing country. Case A corresponds to the case when the host country assumes all the cost.

In Case A Thailand gets zero benefit because it does not own any portion of any project and it merely buys energy at the same cost of its thermal replacement. Vietnam will own those projects located in its territory and therefore will get the benefit of the difference between the cost of energy from such projects and the replacement cost of power. The net benefit to Laos is 26 billion US$, evenly divided between tributary and mainstream projects and the net benefit to Cambodia is 8 billion US$.

Figure 3 - Net Economic Benefits (in billion US$) for Different Cost Sharing and Trade Conditions



Case B shows the situation if the cost of the projects is shared. This is an hypothetical case, only shown for illustration, because neither Thailand or Vietnam would benefit if they have to pay for producing their portion of energy and, in addition, have to pay a high price for importing it. Clearly, the exporting countries will have extremely high, albeit, not realistic, benefits.

Cases C and D: Base Case Trade Price

Case C correpsonds to the base case assumptions used in Chapter 4. The host country assumes all costs and exports power at 85% of the importing country replacement cost.

It is interesting to observe Case D which shows that a trade price of 85% of domestic generation cost is too high to be attractive to Thailand or Vietnam if they have to pay for their share of the project cost.

Cases E and F: Lower Trade Price

Cases E and F are based on the assumtpion of a trade price equal to 70% of replacement cost. At this trade price, Cambodia finds very little benefit unless the cost is shared with the importing country but neither Thailand or Vietnam derive any benefit from importing if they have to share the cost.

Cases G and H: Very Low Trade Price

These cases correspond to the assumption of a trade price equal to half the replacement cost of power in Thailand and Vietnam. At this low price Thailand would derive benefit even if it had to pay for its share of the cost but not so Vietnam, probably due to the higher costs of the projects in which it is named as importer.