VOLUME 3
Solar Alternative to
Sambor Dam

SAMBOR HYDROPOWER DAM ALTERNATIVES ASSESSMENT

FINAL REPORT

[INCLUDES COMPARISON OF DAM AND "NO-DAM" ALTERNATIVES]

A component of
Hydropower Development Alternatives for the Mekong Basin:
Maintaining the Flows that Nourish Life

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Sambor Hydropower Dam Alternatives Assessment
Final Report

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Table of Contents – Volume 3

List of Figures – Volume 3

List of Tables – Volume 3

List of Text Boxes – Volume 3

List of Acronyms and Abbreviations

3S	3S System (Se San, Srepok and Sekong Rivers)
AC	Alternative Current
ACSR/AC	Aluminum Conductor Aluminum Clad Steel Reinforcement
ACSR	Aluminum Conductor Steel Reinforcement
ADB	Asian Development Bank
ADCP	Acoustic Doppler Current Profiler
Alt-6	Sambor Alternative 6 with the dam in the anabranch
Alt-7	Refers generically to all of the Sambor alternatives with the dam in the main channel
Alt_7-A	Sambor Alternative 7 (dam in the main channel) with maximum upstream and standard downstream mitigation
Alt_7-B	Sambor Alternative 7 (dam in the main channel) with maximum upstream and standard downstream mitigation + low-impact (fish friendly) turbines
Alt_7-C	Sambor Alternative 7 (dam in the main channel) with maximum upstream and standard downstream mitigation + screens
Alt_7-D	Sambor Alternative 7 (dam in the main channel) with maximum upstream and maximum downstream mitigation (screens and low-impact, fish friendly turbines)
AWS	Automatic Weather Stations
BDP	The MRC Assessment of Basin-wide Development Scenarios
b	Billion (USD)
BTU	British Thermal Unit
CBA	Cost-Benefit Analysis
CCGT	Combined Cycle Gas Turbine
CDF	Cumulative Distribution Function
CFD (FEA)	Computational Fluid Dynamic (CFD) analysis, subset of Finite Element Analysis (FEA)
cm	Centimeters
CSP	China Southern Power (Grid Company)
CSP FS	China Southern Power Feasibility Study (for Sambor)
Cumec	cubic meters per second
DC	Direct Current
EdC/EDC	Electricite Du Cambodge (Electricity of Cambodia)
EDL	Electricity of Laos
EGAT	Electricity and Gas Authority of Thailand
EOCK	Economic opportunity cost of capital
EPBC Act	The Environmental Protection and Biodiversity Conservation Act 1999
EPRI	Electric Power Research Institute (of the US)
ERR	Economic Rate of Return
EU	European Union
EVN	Electricity of Vietnam
FACTS	Flexible Alternating Current Transmission System
fob	free on board
FOREX	Foreign exchange
FS	Feasibility Study
FSRU	Floating Storage and Regasification Unit (LNG)
FTCC	Floating Tracking Cooling Concentrator
GDP	Gross Domestic Product
GHG	Green House Gas (Emissions)
Gms	grams
GMS5	satellites
GOES9	satellites
GWh	Gigawatt hours

HDPE	High-density polyethylene
HHV	Higher Heating Value (of a thermal fuel)
HPLS2Co	Hydro Power Lower Sesan 2 Company, Ltd.
HSRS	Hydrosuction Sediment Removal System
HVAC	High Voltage Alternating Current (power transmission)
HVDC	High Voltage Direct Current (power transmission)
ICOLD	International Commission on Large Dams
IDC	Interest During Construction
IEEE	Institute of Electrical and Electronics Engineers
IFC	International Finance Corporation
IFI	International Financial Institution (e.g. World Bank, ADB)
INDC	Intended Nationally Determined Contribution
IP 65 or 67	International Protection Marking
IPP	Independent Power Producer
IPCC	Intergovernmental Panel on Climate Change
IRR	Internal Rate of Return
ISO	International Standards Organization
JCC	Japan Crude Cocktail (weighted average of crude imports to Japan)
JICA	Japan International Cooperation Agency
JMA	Japan Meteorological Agency
JNCC	Joint Nature Conservation Committee
K	Kelvin
k	Kilo
kg	kilograms
km	kilometers
kV	kilo Volt
Kw	Kilo watt
KWh	Kilo Watt hours
LCoE	Levelised Cost of Electricity
LHV	Lower Heating Value (of a thermal fuel)
LLW	Lowest Low Water (level)
LMB	Lower Mekong Basin
LMS	Lower Mekong System
LNG	Liquefied Natural Gas
LNG-CCGT	LNG fueled Combined Cycle Gas Turbine
LSS2	Lower Se San 2 (hydropower project)
LTCR	Long Term Capacity Ratio
LV/MV	Lower Voltage/Medium Voltage
m^3	Cubic meters
Mm^3	Million cubic meter
m s^{-1}	meters per second
MAFF	Ministry of Agriculture, Forestry and Fisheries (of Cambodia)
Masl	Meters above sea level (Ha Tien tide gauge if not otherwise noted)
MBC	Mekong Basin Commission
MBTF	Mean time between failures
MDS	Mekong Delta Study
Meteonorm	Meteonorm is a unique combination of reliable data sources and sophisticated calculations tools.
MIGA	Multilateral Investment Guarantee Agency
MGR	Minimum Gap Runner (turbine design)
mmBTU	million British Thermal Units

MME	Ministry of Mines and Energy
MMHSEA	Strategic Environmental Assessment of Mekong Mainstream Hydropower
MMS	Middle Mekong System
mm/yr	millimetres per year
MOEA	Multi-Objective Evolutionary optimization Algorithm
MONRE	Ministry of Natural Resources and Environment (Vietnam)
MoU	Memorandum of Understanding
MoWRaM	Ministry of Water Resources and Meteorology
MRC	Mekong River Commission
MRCS	Mekong River Commission Secretariat
MSY	Maximum Sustainable Yield (of a fishery)
Mt/yr	Million tons per year
MTSAT-1R	satellites
MUV	Manufactured Unit Value (index published by World Bank)
MVA	Mega Volt Ampere
MW	Mega Watts
MWac	MW alternating current
MWh	Mega Watt hours
MWp	Mega Watt peak
NASA	National Aeronautics and Space Administration
NGO	Non-Governmental Organisation
NHI	Natural Heritage Institute
NMFS	National Marine Fisheries Service (Western Pacific States)
NPP	North Phnom Penh
NPV	Net Present Value
NREM	Natural Resources and Environmental Management Research and Training Centre (of Mah Fah Luang University, Thailand)
NT2	Nam Theun 2 Hydropower Project (in Lao PDR)
OAAs	Other Aquatic Animals
ODC	Open Development Cambodia
O&M	Operation and Management (cost of a power station)
PBR	Potential Biological Removal
PDP	Power Development Plan (of Vietnam)
PDP7	7th Power Development Plan (Vietnam)
PECC1	Power Engineering Consulting Joint Stock Company 1 (of Vietnam)
PDR	People's Democratic Republic (of Laos)
PNNL	Pacific Northwest National Laboratory
PPA	Power Purchase Agreement
PPP	Public-Private Partnership
PR	Performance Ratio
PRG	Partial Risk Guarantee (of the World Bank)
PSS or PSS/E	Power Transmission System Planning Software
PV	Present Value
Solar PV	Photovoltaic
PVNEB	Present Value of Net Economic Benefit
RESCON	Reservoir Conservation Model
R&R	Resettlement and Relocation (of persons at a reservoir)
RGC	Royal Government of Cambodia
SBR	Sediment Balance Ratio
SERIS	Solar Energy Research Institute of Singapore
Solar GIS	Accurate and efficient solar energy assessment software

SPV	Special Purpose Vehicle (company established for implementing a project)
SVC	Social Value of Carbon
TVA	Tennessee Valley Authority
UMS	Upper Mekong System
UNFCCC	United Nations Framework Convention in Climate Change
US	United States
$US	United States Dollar
USAID	United States Agency for International Development
USc	US cent
USGS	United States Geological Survey
$USm	Million US dollars
UV	Ultra Violet
VND	Vietnamese Dong
VRE	Variable Renewable Energy (solar PV, wind)
W	Watt
WCD	World Commission on Dams
W/m^{-3}	Watts per cubic metre
y^{-1}	Per year

10 The Floating Solar PV Alternative

The past few years have seen a dramatic reduction in cost of solar photovoltaic power generation (Solar PV). This technology therefore presents a renewable energy enhancement to existing hydropower facilities that avoids the environmental damage costs of building a new hydro project instead.

This technology can be implemented in a variety of different ways, but because of problems with its intermittency – very rapid changes in output when weather conditions produce rapidly changing cloud cover – it poses a range of issues associated with integration of its output into a power grid. At small scale, relative to the size of the power grid, this is not a major issue, but at large scale (100 MW and more), when feeding into a relatively small grid, this becomes a significant issue.

One way of addressing these integration problems is to integrate a solar PV project with a hydro project, which because of the flexibility of power output from hydro turbines, allows in principle the hydro project to function as a large battery, allowing the combined project to deliver into the grid smoothed and dispatchable power. Of course, this requires that there is adequate active storage capacity in the reservoir (so when PV output is at its maximum, the water is stored rather than released during these hours: but then released later in the day when power demand peaks), and that the turbines have quick response times. This mode of operating, however, creates large daily distortions in the downstream flow pattern that can be quite detrimental to the fishery and must therefore be counteracted. These questions are examined in more detail below.

The first such integrated project implemented at a large scale is at Longyangxia in Qinghai Province of China, where 850 MW of PV panels, mounted on land in conventional fashion, was added to a 1,280 MW hydro project. This project is described in some detail in Appendix 10.1, for it serves as the most relevant example for application of the concept to Cambodia. One of the difficulties of a land-based solar component is that large land areas are required. In Cambodia, acquisition of the land and potential conflict with existing uses may pose a serious constraint, and may require the resettlement and relocation of large numbers of persons. But this can be avoided by deploying the solar array on the hydropower reservoir that already exists. This is the concept of floating solar PVs.

For this reason, we have examined the possibility of floating solar PV at the existing LSS2 hydro power project, as an alternative to mainstream power development at the Sambor site. With so many concerns about the environmental impact even the most fully mitigate alternative at Sambor (the Sambor 7A alternative described in this report), we find that a floating PV project is a superior alternative to meet the next increment of power demand in Cambodia.

Figure 10-1. Location of the LSS2 project.

The LSS2 Hydro Project

In 2007, the Royal Government of Cambodia (RGC) gave approval to the Vietnamese *EVN International Joint Stock Company* to undertake a detailed feasibility study (FS) of the Lower Sesan 2 Power Project (LSS2), with a view to a possible joint investment involving Cambodia and Vietnam. The FS was prepared by the Vietnamese consulting firm *Power Engineering Consulting Joint Stock Company 1* (PECC1), in collaboration and consultation with technical ministries and agencies of the Royal Government of Cambodia. The FS demonstrated that the project was technically and economically feasible.

In November 2012, the RGC approved the LSS2 project with an installed capacity of 400 MW, to be implemented by the *Hydro Power Lower Sesan 2 Company, Ltd*. (HPLS2Co). This company was established by the Cambodian Royal Group company in collaboration with the Hydrolancang International Energy Co., Ltd, with a 10% share held by EVN International Joint Stock Company (owned by the Government of Vietnam).[1] The implementation agreement was signed on 26 November 2012. Subsequently Electricity of Cambodia agreed to take 100 % of LSS2 power generation for the national grid[2]

In January 2013, RGC enacted a law to provide two guarantees: a warranty for payment for power in the event of default by were EdC; and a warranty to purchase the project if its intended implementation were made impossible for reasons of political force majeure. It should be noted that none of the key documents on implementation were made available to the Natural Heritage Institute (NHI): we have not sighted the original PECC1 feasibility study, the Implementation Agreement, nor indeed the subsequent power purchase agreement (PPA) between HPLS2Co and EdC. The only information on implementation arrangements in the public domain sighted by NHI is the explanatory note on the project published at the time the draft law was submitted to the National Assembly in early 2013.[3]

Figure 10-2. The LSS2 Project.

[1] According to Press reports (Khmer Times, 11 July 2017), the Royal Group of Cambodia has a 39% share, and HydroLancang a 51% share.

[2] We understand that EVN has retained some equity share in recognition of the costs of the FS.

[3] Draft Law on Authorization of Payment Warranty of the Royal Government of Cambodia for the Hydro Power Lower Sesan 2 Company, Explanatory Note 01, 2013 (unofficial translation).

The 400 MW LSS2 project is configured with 8*50MW bulb tubular turbine generator sets with an expected average annual output of 1,912 GWh. The reservoir has a total gross storage of 1792.5 million cubic meters (MCM), of which the active storage is 333.3 MCM.

LSS2 was inaugurated on 25 September 2017: commissioning and first power is expected in December 2017.

Transmission Arrangements

Under the terms of the Implementation Agreement, HPLS2Co is responsible for the construction and operation of just the 32 km 230kV line from the power project to a Cambodian grid substation at Stung Treng. The 2 x 230kV transmission grid connection from Stung Treng to Phnom Penh is being constructed as a separate private power project by a subsidiary of the Malaysian company *Pestech* under a 25-year agreement with EdC. Annual wheeling charges are expected to be US$12.2 million for the first three years, and US$18.2 million for the remaining 22 years. Neither the agreement with EdC, nor the technical details of the line as actually constructed, were made available to NHI, and so we assume, but do not know with certainty, that the technical characteristics of this line conforms to the designs proposed by the JICA transmission study.

The NHI Study Hypothesis

Under ideal conditions, an integrated solar PV project (whether floating or not), and its conventional hydro project partner, would be designed and constructed as a single enterprise. The principal question for such an integrated design is the choice of turbine, which would be chosen in light of the trade-off between cost and rapid response time: particularly in low head situations, somewhat higher-cost conventional Kaplans would likely be chosen to accommodate PV over lower cost, but less flexible, bulb turbines. Had the best alternatives at Sambor (such as Alt_7) met our design objectives for an environmentally sustainable hydro development project, we would doubtless also have included a solar PV add-on. But, **in light of our conclusion that *no* mainstream hydro project on the lower Mekong is economic when environmental externalities are properly included in the economic analysis, to examine the floating PV option on the basis of Sambor Alt_7 was considered pointless.**

Consequently, we have chosen to examine the floating solar PV option on an existing hydropower reservoir as an *alternative* to any Sambor Dam alternative on the mainstream Mekong. The LSS2 project is the logical first candidate as the largest existing hydropower project in Cambodia. It is recognized that an ideal single integrated project design is not available at LSS2, particularly since the turbines are already in place,[4] but it nevertheless provides the best available basis for assessing the floating PV option at the pre-feasibility study level.

The first practical question about such a proposal is how would such an add-on be implemented. For certain this would be implemented as an Independent Power Producer (IPP) since the reservoir is already owned and operated by private developers. Since the whole point of the concept is to integrate closely the electrical systems and operational performance of the PV and hydro

[4] The technical details of the turbines actually installed at LSS2 have not been provided to NHI. We believe these to be a bulb turbine of standard Chinese design, but without more detailed information on its design, there remains significant uncertainty about maximum ramp rates.

components, it would not be practical to bring in a *new* developer to implement a solar PV add-on.[5] In short, only if HPLS2Co is interested in developing the additional floating PV project at LSS2, would a detailed FS be undertaken at LSS2, and could such a project actually implemented.

PPA Issues

However, this may be, the additional energy produced will need to be covered by a PPA. The options on how that solar PV-PPA could be structured is a function of two main issues: the likely cost of the additional PV energy; and the structure of the existing PPA that governs the sale of hydro energy from LSS2.

As noted, the existing LSS2 PPA has not been made available to the NHI study team, and we are therefore dependent on such limited information as is already in the public domain. We know that:

- The purchase/sale is based on the principle of "take-or-pay basis".
- The price of excess power purchase/sale is equal to 60% of the base power cost
- The internal rate of return (IRR) is 12.59%.
- The concession period is 45 years, including 5 years of construction and 40 years of business operation.
- The quantity of annual power production is 1.912 million kw hours.
- The base power cost is US$0.0695 per kWh hour (delivered to the Stung Treng substation).

What is *not* known to us includes:

- How is "surplus" energy and "base power" defined?
- What exactly means "quantity of annual power production"? Is this the expected *average* generation?
- Whether the PPA contains any "deemed energy" provisions or other terms and conditions that relate to very dry years (e.g. carryover provisions)?
- What understandings have been reached with the EdC on likely dispatch instructions (it is not necessarily the case that the dispatch pattern requested corresponds to the best operating point that would maximize HPLS2Co revenue).
- What provisions cover modifications of the PPA where such modifications are sought by and seen advantageous to both parties.

In the ideal case, the additional solar PV energy could be profitably produced during daylight hours at (or at less than) 6.95 USc/kWh as applies to the hydro generation, in which case a simple codicil to the existing PPA would suffice to obligate take-or-pay of the additional energy at the same price (to some maximum expected incremental production). However, that is unlikely to be the case. Even more unlikely is that the solar PV energy could be produced at 4.2 USc/kWh (i.e. 60% of the base power cost, as would apply to "surplus" energy). In short, we can safely conclude that any additional solar PV energy would require a price that is higher than the existing hydro price, and would therefore require either a substantive revision of the existing PPA, or a separate PPA covering only the solar PV power. In any event, nothing precludes the parties from modifying the PPA by mutual consent. That said, as PV prices continue to decline, at some point in the mid 2020s the generating cost of PV power will likely fall below that of conventional hydro.

[5] A separate special purpose vehicle (SPV) might indeed be proposed to implement the floating solar project, bringing in additional investors, but the SPV would necessarily require majority ownership and full operational control of HPLS2Co.

The main question for any additional PPA is how to establish the quantity of solar energy that the seller is permitted to sell at the higher price. The *total* quantity would be measured, as now, at the existing metering facility. The proportion of PV would vary from day to day, and from hour to hour, but the total PV energy can be metered at some point between the onshore collection point and the main LSS2 switchyard.[6] There should be no problem providing check metering facilities to separate hydro and PV generation and relaying this information to Stung Treng.

Financing issues

The many questions surrounding the financing constraints for a large mainstream hydro project at Sambor are discussed in Chapter 11. A solar PV add-on at LSS2 will depend crucially on the financing arrangements, since the tariff necessary to achieve an adequate return to the equity investors are directly related to the cost of debt finance. The most obvious approach to achieve a lower cost of debt is to secure concessional finance - impossible at Sambor, difficult even for smaller hydro projects, but relatively easy for solar-PV.

Concessional finance means that the borrower must conform to the safeguard policies of the international finance institutions, such as the World Bank, the International Finance Corporation, or the Asian Development Bank, which in the case of a hydro project have two requirements likely to be seen as onerous to any developer and the RGC:

- A project on an international river requires a written "no objection" certification of the downstream riparian, in this case, of the Government of Vietnam.
- Resettlement and relocation (R&R) provisions must meet requirements of the IFIs.

An important advantage of floating PV is that neither of these two constraints apply. There exist no riparian issues (indeed to the extent that floating PV reduces evaporation, the supply to downstream riparians even increases), so a *no objection* certification is unnecessary. Nor is any resettlement and relocation of persons required, avoiding all of the possibly onerous and time consuming procedures to demonstrate compliance with IFI conditions for R&R.

The best approach to obtaining concessional finance and lower the cost of debt would be to structure the SPV as a public-private partnership (PPP), and bring in the private sector arms of one of the IFIs as a minority equity partner (e.g., the International Finance Corporation (IFC) of the World Bank Group, or the private sector arm of ADB). These have the necessary know-how to apply for and secure concessional finance and further risk mitigation options (e.g. partial risk guarantees from the Multilateral Investment Guarantee Agency (MIGA).[7]

[6] It is true that one might hypothesize a completely separate entity to build, own and operate the floating PV add-on, with this entity having a PPA with the LSS2 operator at this metering point. However, the PV operator would need a take-or-pay agreement with the hydro operator, but such an agreement would be out of the question for the hydro operator because he needs the freedom to curtail the PV, or otherwise cease PV operation for safety or stability reasons. The hydro project operation will always have priority.

[7] This is part of the World Bank Group, and therefore follows all of the procedures and safeguards of the World Bank. MIGA has provided so –called partial risk guarantees (PRG) to a number of hydro projects, which typically costs 25 basis points (0.25%) of the outstanding debt service obligation plus a small up front fee. But with this guarantee, commercial lenders will lower the interest rate (and lengthen the tenor) of loans to the entity that benefits from the guarantee.

It may be objected that any kind of IFI finance would require a sovereign guarantee. But as we have seen at LSS2, a Government guarantee would also be required for a purely private project as well, so in terms of headroom limitations for additional guarantees, whether implementation as purely private or as a PPP would make little practical difference.

Potential Disruption to Ongoing Operations at the Hydro Site

The one issue that can be predicted with high certainty is that whatever additional construction or modification may be required for the solar add-on, existing operations must not be significantly disrupted. However, there is no reason to believe that assembly and erection of the floating panels, and the electrical connections to the onshore substation, and any necessary civil works, would in any way negatively affect ongoing operations of the hydro station. It is in any event in the interest of the hydro operator to keep water level fluctuations to a minimum (and at as high an elevation as possible to maximum head), so we see no reason that construction and erection of the panels in the reservoir would require deviations from the operating rule already agreed with EdC, or as desired by the hydro project owner. Moreover, with construction of the hydro project complete, heavy road works and site traffic associated with hydro construction are all complete, so again there would be no conflict with ongoing hydro project operations.

The only possible disruption would be when the cable from the PV collector must be connected to the main switchyard. Again, we see no reason why, with proper planning, the necessary modifications to the switchyard cannot be completed without significant disruption. During the dry season when electricity generation would be limited to a few hours of the evening peak, or indeed during annual scheduled maintenance hours, there would be adequate opportunity to make the necessary switchyard and control system changes. In any event, if indeed the solar PV add-on is beneficial to both parties (EdC and the LSS2 owner), we are sure that the necessary commissioning arrangements for a short transition period can be reached that would not be disruptive to ongoing operations. Since for reasons noted above the owner/operator of the solar-PV project must necessarily be the same as (or have full operational control over) the existing operator, it should be easy for the owner operator to make the necessary arrangements in his best interest, so as to avoid any loss of revenue.

In short, we see no reason why construction of the floating PV system add-on would pose any material risks to on-going operations at the hydro site.

Potential Disruption to Transmission Line Operations

It is unlikely that any changes will need to be made to the transmission interconnection arrangements for the first 50 MW or so of PV development. However, as additional tranches of PV and associated fast acting storage facilities are installed (depending on the early operational experience with a hybrid PV/Hydro installation), it may be necessary to build an additional 220 kV line to Sung Treng to maintain a nominal “n-1” reliability standard. The construction and subsequent interconnection can be completed without disrupting existing operations and should not present any undue difficulties. Likewise, if there is a need to enhance existing reactor facilities at intermediate 230kV grid substations these too can be completed off time and commissioned at an appropriate time without disrupting production.

Cambodia's Solar Resource

Solar energy potential in Cambodia is considered high, with an average of slightly over 5 kWh/m^2 per day, equivalent to 1,800-1,900 kWh/m^2 per year (Figure 10-3) and average sunshine duration of 6–9 hours per day. Solar energy is estimated to have technical potential of 8,100 MW and energy output of 14,781 GWh per year. As discussed in Appendix 10-2, solar PV could provide 5-10% of the total energy requirement without incurring significant grid integration problems.

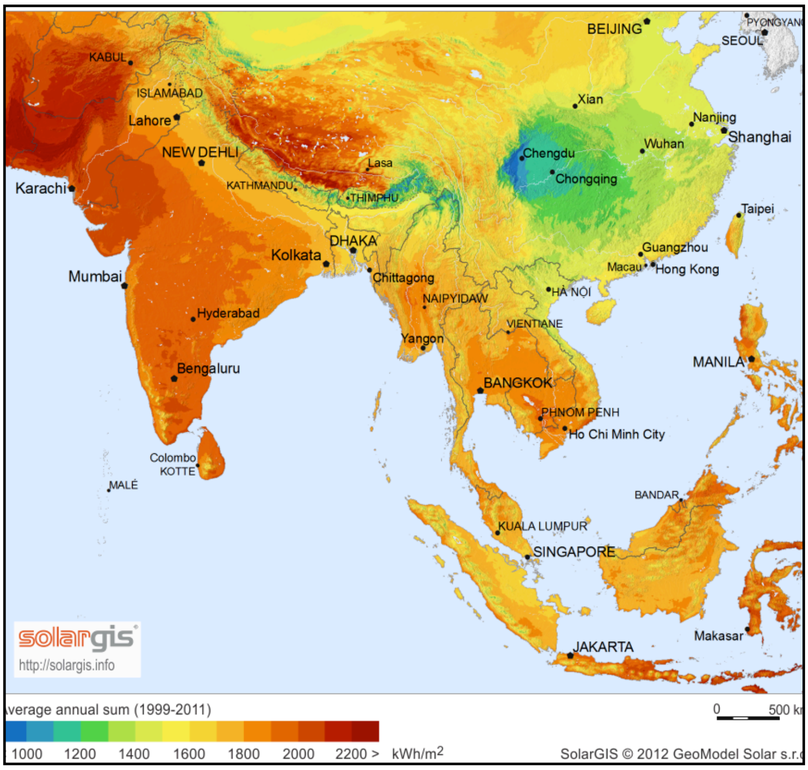


Figure 10-3. Solar resource map for Asia. Source: SolarGIS.

As solar radiation has diurnal, seasonal and inter-annual variations, long-term solar radiation data are usually required for solar energy system design. Ideally, solar radiation data from the measurements at the site where the systems are intended to build should be used for designing solar energy systems. However, in reality, such data are usually not available and the radiation data from the nearest solar radiation measuring station are employed instead. Due to equipment and maintenance costs, the numbers and density of the stations in developing countries are usually far too low to provide sufficient solar radiation data. As an alternative, satellite data can be used to derive solar radiation data, with a reasonable accuracy, especially for a long-term average global radiation.

There has been little systematic solar radiation measurement in Cambodia. Since early 2000's, the Ministry of Water Resources and Meteorology (MoWRaM) has started installation of Automatic Weather Stations (AWS) throughout Cambodia. By Dec 2007, there were only 9 AWS. The current map of AWS network is shown in Figure 10-4. The closest station to LSS2 is that at Stung Treng[8]. This station has irradiance measurements among other common weather parameters, and could provide useful historical climate data for the further assessment of potential solar project at LSS2.

[8] Long: 105.967E, Lat: 13.517N

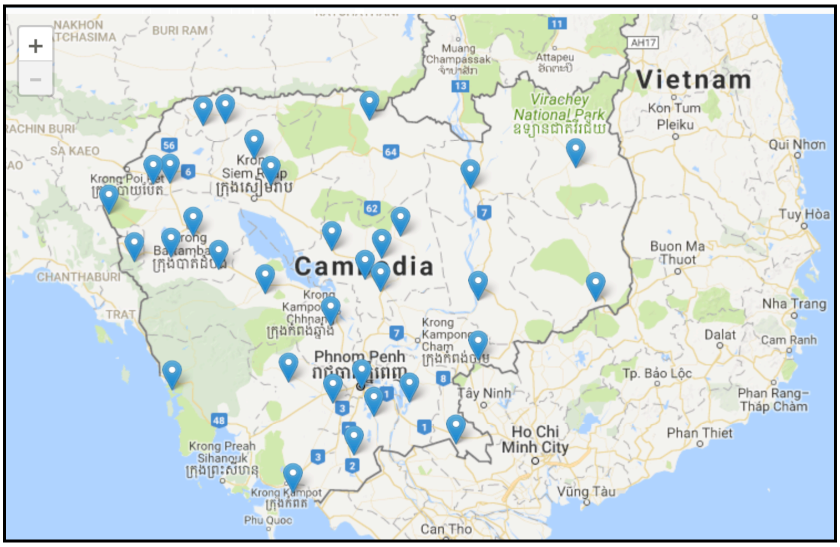


Figure 10-4. Map of Automatic Weather Stations (AWS) in Cambodia. Source: Wesoff and Lacey, 2017.

Some free satellite databases are available online that provide further information (e.g. NASA) (Hartzell, 2017). An interesting article estimates solar radiation over Cambodia from long-term satellite data (The Business Times, 2017). In that study, monthly solar radiation maps of average daily global solar irradiation over Cambodia was estimated from a long-term satellite data (14-year period 1995–2008 of visible channel data from GMS5, GOES9 and MTSAT-1R satellites). These maps show clearly that solar radiation is strongly influenced by the monsoons.

Table 10-1. Monthly global horizontal insolation (kWh/m2/day].

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
22-year Average	5.61	6.01	6.11	5.91	5.41	5.03	4.88	4.56	4.57	4.87	5.11	5.21	5.26
Minimum and Maximum Difference from Monthly Averaged Insolation (%)													
Minimum	-9	-14	-9	-8	-9	-10	-17	-15	-17	-15	-20	-13	
Maximum	5	7	8	6	8	13	17	19	14	10	15	10	

Source: NASA Surface meteorology and Solar Energy website. Hartzell, 2017.

For this current study, solar potential and long-term climate data are obtained from the commercial software Meteonorm, which combine satellite data and ground station data with interpolation, coupled with computational models to generate hourly radiation data[9]. These hourly time series can then be used for PV system yield prediction as inputs. Such method provides more accurate estimation of solar resources, and becomes often the commonly used approach for solar resource assessment[10].

Figure 10-5 and Figure 10-6 show the obtained solar irradiance data at LSS2 project site. Other major meteorological parameters, e.g. ambient temperature, precipitation, are shown in Figure 10-7 and Figure 10-8.

9 Hourly values are designated by the end time of the interval. Thus, the value for 14.00 hours refers to the average value of the interval from 13.00 to 14.00 hours (Hannen, 2017).

10 Alternatively, by such commercial software as that of SolarGIS. http://solargis.com/

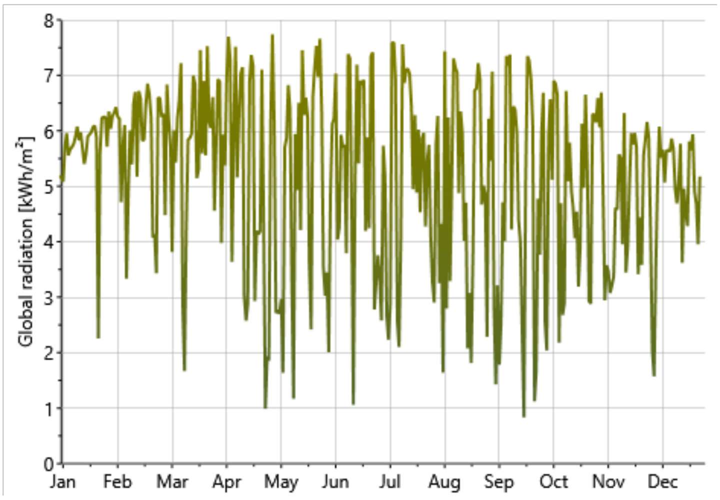


Figure 10-5: Daily Global Horizontal Irradiance [kWh/m2].

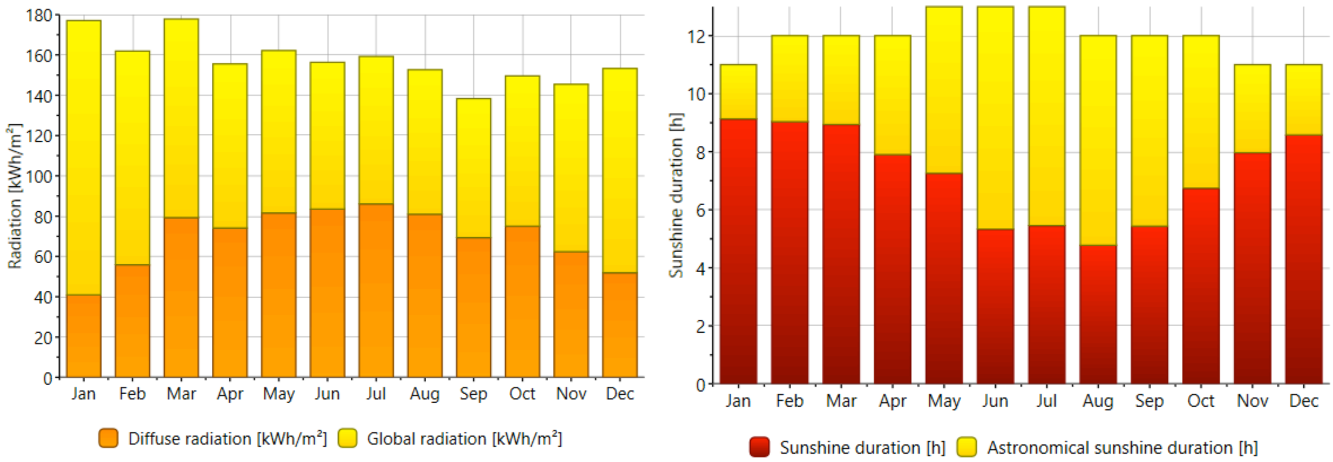


Figure 10-6: (Left chart) Monthly Global radiation and the diffuse component [kWh/m2]. Direct + Diffuse = Global radiation. (Right chart) Sunshine duration [hour].

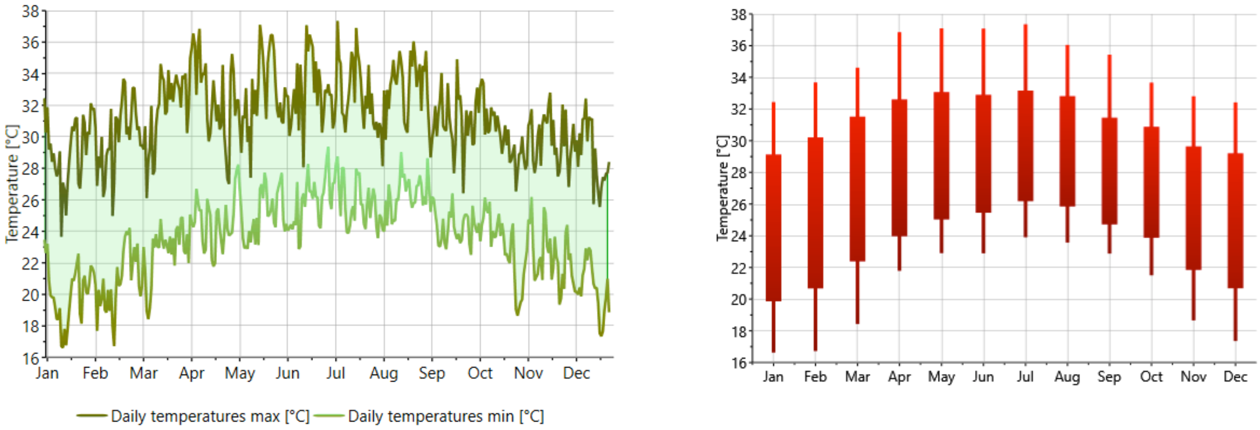


Figure 10-7. (Left) Daily ambient temperature range (min, max) [°C]. (Right) Monthly temperature ranges with quantiles [°C].

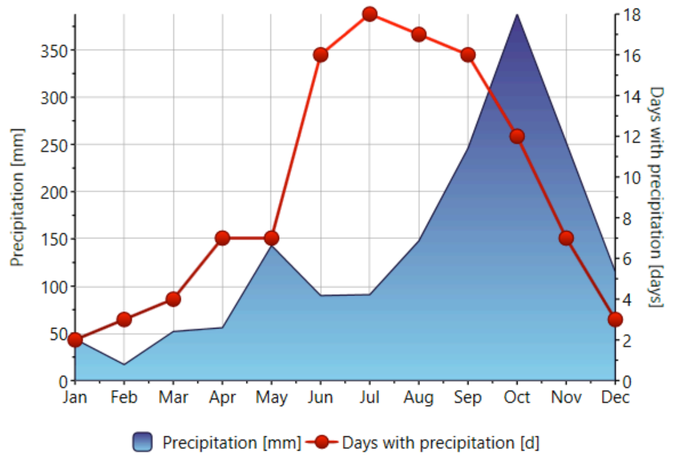


Figure 10-8: Monthly Precipitation [mm] and number of days with precipitation per month.

Under the Monsoon's influence, there are two typical seasons in Cambodia. The northeast monsoon season runs from December through April, bringing sunny, dry weather especially in January and February. The rains come when the winds shift into the southwest monsoon from May to November, with the most precipitation in the months of September and October. This can also be observed from Figure 10-8.

Figure 10-9 shows the impact of monsoon seasons in Cambodia on PV system production. During the rainy season (May - Nov), the cloudy weather reduces the solar insolation and thus the PV energy production. Solar PV production is higher in the dry season (Dec - Apr), and peaks in Jan/Feb.

The largest uncertainty in estimating the yield of a PV farm comes from the uncertainty of estimation in solar resources. Such uncertainty can be attributed to the following three points (Bebon, 2017):

- Uncertainty of ground measurements (measurement itself and long term variability of local climate),
- Uncertainty of interpolation (interpolation of ground measurements and uncertainty of satellite based data),
- Uncertainty of the splitting into diffuse and direct radiation and inclined planes.

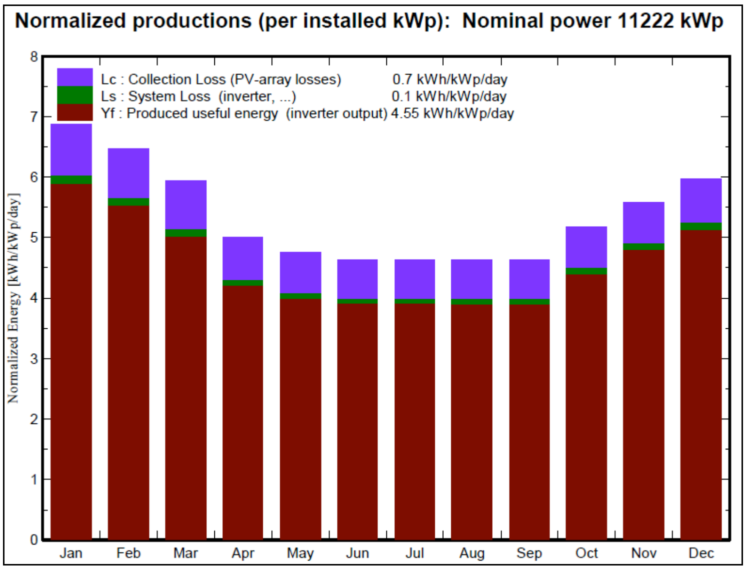


Figure 10-9: Monthly PV production.

The results obtained from Meteonorm has an associated uncertainty of 9% for the yearly global horizontal irradiance (GHI), with year-to-year variability of 5.4%. The 9% uncertainty may still be relatively large, which should be investigated in any detailed feasibility study. The data from SolarGIS[11] can be explored, or site-adaptation methods of satellite-based data with at least 9-12 months of ground-measurements at the project site can be applied (Colville, 2017).

PV Energy Yields at LSS2

PV system energy yields are estimated at the LSS2 project site, for various system configurations. In particular, the yield of ground-mounted PV system is compared with floating PV system, and various tracking options are considered as well, for both ground-mounted and floating PV configuration.

Baseline Case – 10MW Ground-mounted PV System

Following the modular design of a PV system, a 10 MW ground-mounted PV system is considered as the baseline case. For system of larger installed capacity, multiples of the 10 MWp blocks can be applied with the essentially the same conditions.

The Meteonorm data as described in the previous section are used as inputs for yield prediction modelling. Central inverter design with 2,500 kWac Sungrow central inverters (SG2500HV) is used to reflect the design of the 40 MW Sungrow floating PV project, and 300 Wp Trina Solar 72 cell glass-glass modules (TSM-300PEG14) are selected as PV modules. The design details can be found in the corresponding PVSyst report.

The modelled 10 MWac PV system (with installed DC capacity of about 12MWp) produces 18,785 MWh/year, with a specific energy yield 1,570 kWh/kWp/year and a Performance Ratio (PR) of 80.33%.

[11] In fact, SolarGIS also claims that the expected bias can be as high as ±8% for GHI values, for countries in humid tropical climate (e.g. equatorial regions of Africa, America and Pacific, Philippines, Indonesia and Malaysia) and coastal zones (approx. up to 15 km from water); and regions with limited or no availability of high-quality ground measurements. Source: http://solargis.com/support/knowledge-base/accuracy/overview/

Table 10-2.: 10MW ground mounted PV system.

	GlobHor kWh/m²	DiffHor kWh/m²	T Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray MWh	E_Grid MWh	PR
January	177.0	40.93	24.31	213.3	206.5	2090	2042	0.800
February	161.9	55.90	25.25	181.4	175.2	1774	1734	0.799
March	177.7	79.32	26.81	184.2	176.8	1802	1762	0.800
April	155.3	74.12	28.14	150.3	143.6	1463	1430	0.796
May	162.2	81.56	29.00	147.3	140.3	1446	1414	0.802
June	156.2	83.50	29.10	139.1	132.2	1371	1341	0.806
July	159.3	86.08	29.57	143.7	136.9	1417	1386	0.806
August	152.6	80.96	29.21	143.7	137.0	1410	1379	0.802
September	138.3	69.34	27.99	138.8	133.2	1361	1330	0.801
October	149.5	74.99	27.24	160.3	153.9	1582	1547	0.807
November	145.4	62.33	25.59	167.7	161.4	1664	1628	0.811
December	153.3	51.91	24.81	185.2	178.8	1833	1792	0.809
Year	1888.9	840.95	27.26	1955.0	1875.9	19214	18785	0.803

Legends:				
	GlobHor	Horizontal global irradiation	GlobEff	Effective Global, corr. for IAM and shadings
	DiffHor	Horizontal diffuse irradiation	EArray	Effective energy at the output of the array
	T Amb	Ambient Temperature	E_Grid	Energy injected into grid
	GlobInc	Global incident in coll. plane	PR	Performance Ratio

10MW Floating PV System

With roughly the same assumptions, a 10MW floating PV system is then modelled. The key difference here is however the modelling of the cooling effect due to water evaporation. It has been reported that floating PV system has higher energy yield compared with a ground-mounted system with the same design.

In PVSyst (Hannen, 2017), the thermal behavior of the PV system, which strongly influences the electrical performances, is determined by an energy balance between ambient temperature and cell's heating up due to incident irradiance:

$$U(T_{cell} - T_{amb}) = \alpha G_{inc}(1 - Eff)$$

where

α	=	is the absorption coefficient of solar irradiation
Eff	=	is the PV efficiency (related to the module area), i.e. the energy removed from the module.
Tcell	=	Temperature of the cell
Tamb	=	Ambient temperature
U	=	Thermal loss value (defined below)

The thermal behavior is characterized by a thermal loss factor designed by *U-value*, which can be split into a constant component U_c and a factor proportional to the wind velocity U_v:

$$U = U_c + U_v v$$

where

v	=	wind velocity in [m/s]).
U	=	W/m²·k

These factors depend on the mounting mode and mounting structures.

In order to model the cooling effect, higher U-values are applied for floating PV systems compared to the ground-mounted counterpart, as shown in Table 10-3.

Table 10-3: Thermal loss factors used in the energy yield modelling for ground-mounted vs floating PV systems.

	Uc (in W/m^{2}K)	Uv (in W/m^{2}K)
Ground-mounted PV	20	0
Floating PV (*)	30	3

* The company C&T uses a more aggressive value Uc=39 (via private communication).

These thermal loss factors are observed and fitted from the floating PV testbed in Singapore as well and plotted in Figure 10-10. As shown, the U-value can range from 20 to over 50 depending on the floating structure design.

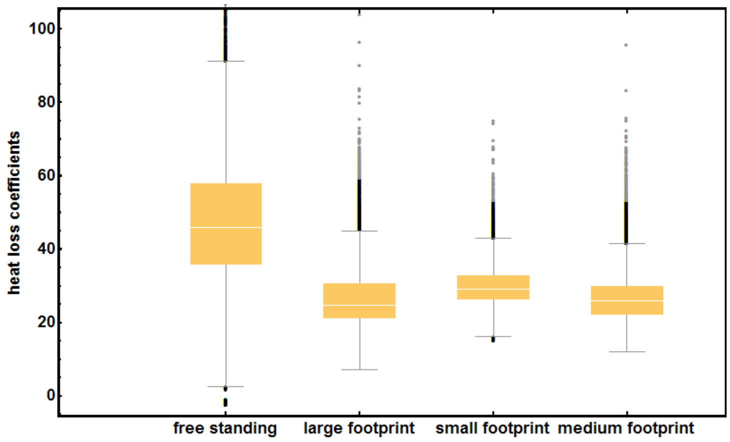


Figure 10-10. Extracted heat loss coefficients for different types of floating structures from the floating PV testbed in Singapore. Higher values correspond to better cooling. The floating structures are roughly categorized into a free-standing type, and three close to water surface types, differentiated by the extent of water surface coverage beneath the modules (from small footprint to large footprint).

Applying the U-values listed in Table 10-3, the simulated PV module temperature distribution can be observed and compared, as shown in Figure 10-11. It is clear that the floating PV module temperature is relatively lower. The modelled energy yield is thus higher.

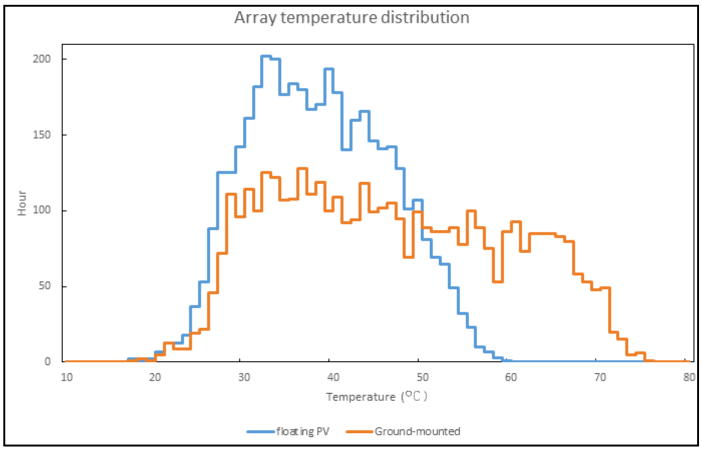


Figure 10-11. Simulated PV module temperature distribution, ground-mounted vs. floating PV.

Table 10-4. Comparison of simulation results for baseline model ground-mounted and floating PV system. The nominal AC power is kept the same at 10MWac.

	Ground-mounted PV	Floating PV
Total Array Nominal Power @STC (kWp)	11,962	11,222
Total Inverter Power (kWac)	10,000	10,000
DC/AC ratio	1.20	1.12
Produced Energy (MWh/year) *	18,785	18,628
Specific Energy Yield (kWh/kWp/year)	1,570	1,660
Performance Ratio (%)	80.3	84.9

* The produced energy is roughly the same, but realized with less solar modules installed for the floating PV system (relative 6.2% less).

Due to the higher module power, the optimal DC-AC ratio should be smaller than a similar ground-mounted system. DC-AC ratio of about 1.1 is selected for the floating PV system model (Table 10-5). As a result, keeping the same AC nominal power of 10 MWac, the floating PV system uses fewer PV modules, i.e. 37,408 (floating) versus 39,872 (ground).

Table 10-5. 10MWac Floating PV (at the LSS2 site).

	GlobHor kWh/m²	DiffHor kWh/m²	T Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray MWh	E_Grid MWh	PR
January	177.0	40.93	24.31	213.3	206.5	2099	2050	0.857
February	161.9	55.90	25.25	181.4	175.2	1779	1737	0.854
March	177.7	79.32	26.81	184.2	176.8	1790	1750	0.847
April	155.3	74.12	28.14	150.3	143.6	1450	1417	0.840
May	162.2	81.56	29.00	147.3	140.3	1423	1392	0.842
June	156.2	83.50	29.10	139.1	132.2	1345	1316	0.843
July	159.3	86.08	29.57	143.7	136.9	1393	1362	0.845
August	152.6	80.96	29.21	143.7	137.0	1388	1357	0.842
September	138.3	69.34	27.99	138.8	133.2	1345	1314	0.843
October	149.5	74.99	27.24	160.3	153.9	1568	1533	0.852
November	145.4	62.33	25.59	167.7	161.4	1652	1615	0.858
December	153.3	51.91	24.81	185.2	178.8	1826	1785	0.859
Year	1888.9	840.95	27.26	1955.0	1875.9	19058	18628	0.849

Legends:				
	GlobHor	Horizontal global irradiation	GlobEff	Effective Global, corr. for IAM and shadings
	DiffHor	Horizontal diffuse irradiation	EArray	Effective energy at the output of the array
	T Amb	Ambient Temperature	E_Grid	Energy injected into grid
	GlobInc	Global incident in coll. plane	PR	Performance Ratio

For floating PV systems, the PV module temperature can be further reduced by applying active cooling of water, directly pumped from the water body underneath the system (as shown in Figure 10-12). The timing and amount of water spraying has to be carefully controlled to guarantee a positive energy gain (i.e. improvement in energy production must be larger than the energy used in the pumping system). To date, only a few research demo systems have been set up in Europe, Japan and at the Singapore test bed. However, the effectiveness and economics of such active cooling system requires further evaluation.

Figure 111-12: Floating PV system with active cooling, which may further enhance system performance and energy production (demonstration system built in Japan by Ciel et Terre).

Table 10-6 summarizes the comparison of the floating PV and ground-mounted systems.

Table 10-6: Summary comparison of ground-mounted and floating PV.

Ground-mounted PV	Floating PV
Advantages ➢ Majority of utility-scale PV farms are ground-mounted; most experiences ➢ More scope and lower cost to install a sun tracking system ➢ Relatively less environmental risks ➢ Easier access and O&M	**Advantages** ➢ No occupation of land, saves precious land for agricultural and other activities; utilizing idle (non-revenue generating) water surfaces, e.g. dams, reservoirs, lakes, etc. ➢ Higher energy yield, due to evaporative cooling effect of water, little shading & soiling loss ➢ Faster installation ➢ Reduction in water evaporations ➢ Water available for cleaning of PV modules
Disadvantages ➢ Less available land for PV, competing land use with agriculture ➢ Land permit issues, site purchase or lease required; possible land use change required (time consuming process) ➢ Higher land/space related cost, e.g. land preparation ➢ Solid foundations and concrete footing needs to be built to provide stable structure protecting from storms and high winds[12]	**Disadvantages** ➢ Higher installation cost (15 ~ 25% as of today) ➢ More difficult O&M ➢ More prone to extreme weather conditions, e.g. high tides, strong winds

[12] The first 10MWp utility scale PV farm in Cambodia currently being built has to take into account the impact of flooding and therefore higher land preparation cost for elevated foundation and/or formal drainage.

PV Systems with Single- and Dual-axis Tracking

PV systems can be mounted on trackers to enhance its performance and energy production. The main tracker types are illustrated in Figure 10-13.

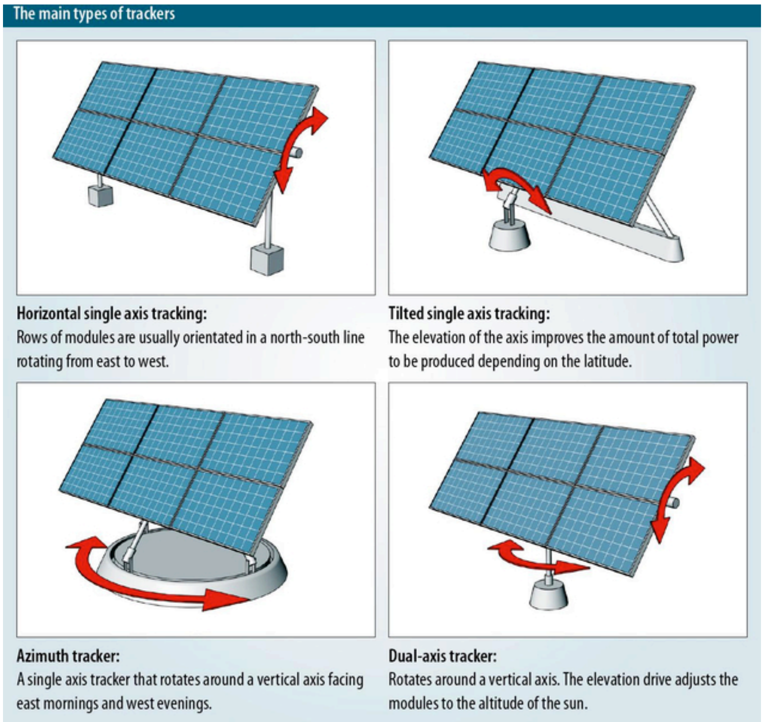


Figure 10-13. Main types of trackers for PV systems

Single axis solar trackers are less expensive and more reliable compared with dual axis trackers, because they do not require as much maintenance and are not as complicated as dual-axis trackers. Single axis trackers are available in horizontal or vertical designs. The vertical axis is ideal for northern or southern regions because the sun doesn't reach as high as it does above the equator. Horizontal trackers are best used in tropical regions because the sun is high at midday. Dual axis trackers come at a higher price and have more maintenance needs. However, they are more efficient than single-axis trackers.

In general, single-axis trackers improve the energy output of a solar farm by about 30 to 35%, whereas dual-axis trackers can boost efficiency by 36 to 41% (Sandler Research, 2015). The DC-AC Ratio can be further reduced, due to higher energy production by PV modules per kWp installed. DC-AC ratio of unity is chosen, which may need to be further optimized for an actual project implementation. Full design details and assumptions can be found in the corresponding PVSyst reports.

Note that for 1-axis tracking, the tilted single-axis tracking is selected for ground-mounted system which is a common design, while the azimuth tracker around a vertical axis is selected for floating PV systems which is more common for floating PV systems.

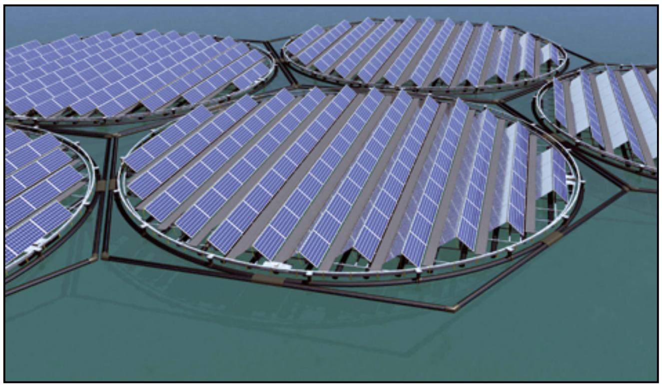



Figure 10-14. (Left) Floating Tracking Cooling Concentrator (FTCC) System concept. The tracking is realized as an azimuth tracker, i.e. rotates around a vertical axis. (Right) a FTCC pilot installation in an irrigation reservoir near Colignola, Pisa. Source: Tan, 2017.

Figure 10-15: Infratech wastewater facility, Jamestown, Australia, with azimuth tracking (1-axis, vertical).

Figure 10-16. Sunenergy Liquid Solar Array, Tata Power hydro dam, India, with dual-axis tracking and concentrators.

The power curve for any PV array mounted on a tracker is broader than that for a fixed array, adding broader "shoulders" to the daily generation curve. Figure 10-17 shows the relative power curves for float-plate PV mounted at a fixed tilt, on single-axis tracker and dual-axis tracker. Based on the energy yield prediction calculations, the energy gains of single axis tracking over fixed tilt PV system are significant, however the gains from 1-axis tracking to 2-axis tracking are relatively small.

Therefore, the additional complexity and extra cost associated with dual-axis tracking do not justify its performance gain. In addition, tracking for floating PV applications are only applied in demonstration projects, there are no major deployment of trackers on water yet. Consequently, the six PV system configurations considered can be reduced to the three that are worth further investigation, namely floating PV system with fixed tilt, ground-mounted system with fixed tilt and ground mounted system with 1-axis tracking.

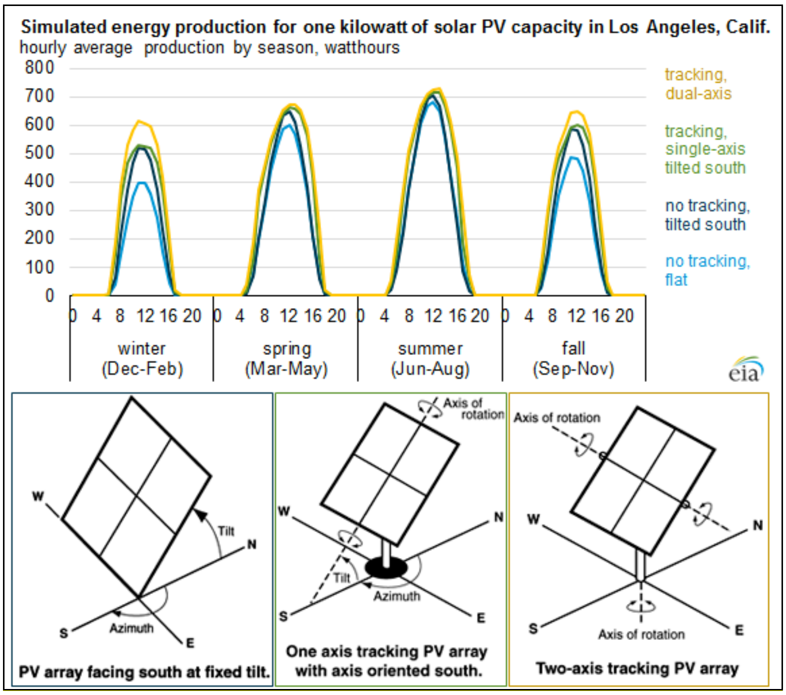


Figure 10-17. Simulated energy production.

Summary of Energy Yield Prediction

An energy yield analysis has been performed comparing a 10 MW_p floating PV to a ground-mounted PV system, using a fixed-tilt design and as well 1- to 2-axis tracking systems. Tracking systems are gaining popularity especially in regions with high so-called “direct” irradiance (less “diffuse” irradiance) and/or where incentives exist to shift production away from the noon time (e.g. high after-noon peak prices in the U.S (Grin & Mayer, 2017). Table 10-7 summarizes the energy yield calculations for the major design options.

Table 10-7. Summary of energy yield prediction results for major design configurations.

	Ground-mounted PV(1)			Floating PV(1)		
	Fixed tilt	1-axis (2)(tilted N-S)	2-axis	Fixed tilt	1-axis (2) (vertical)	2-axis
Total Array Nominal Power @STC (kWp)	11,962	9,860	9,860	11,222	9,860	9,860
Total Inverter Power (kWac)	10,000	10,000	10,000	10,000	10,000	10,000
DC/AC ratio	1.20	0.99	0.99	1.12	0.99	0.99
Produced Energy (MWh/year)	18,785	19,540	19,650	18,628	19,990	20,870
Specific Energy Yield (kWh/kWp/year)	1,570	1,983	1,993	1,660	2,028	2,118
Performance Ratio (%)	80.3	81.0	78.8	84.9	85.1	83.7

Notes: (1) These results are subject to the assumptions used for yield predictions. (2) The axis orientations for 1-axis tracking designs are selected differently for ground-mounted and floating PV respectively, according to the predominant commercially available designs.

While the energy generation in tracking systems can be increased between 20-30% (Wesoff, 2016) there is additional investment needed. In addition, it also adds complexity to the system configuration and causes increased maintenance cost. While 1-axis tracker systems are already widely adopted in the U.S. for ground-mounted systems, dual tracking systems, due to their additional complexity, are still rarely implemented (NREL, 2017). In addition, floating PV in combination with tracking systems is still at the testing stage in some regions and do not yet appear to be commercially widely available and acceptable by banks. It was therefore decided to focus the detailed assessment to the following options: i) ground-mounted PV system fixed tilt, ii) ground-mounted PV system using a 1-axis tracking system and iii) floating PV fixed tilt.

Other Proposals for PV Development in Cambodia

The impact of other comparably sized PV facilities on power system stability will be similar to the impact a large PV facility at LSS2. Accordingly, it will be necessary to coordinate technical studies to ensure that the intermittency of *all* PV power production facilities can be absorbed by the spinning reserve capacity in the 230kV grid.

The 10 MW Sunseap project will likely be the first utility-scale solar power project in Cambodia, with capacity of 10 MWp. The Project is located in Bavet City, Svay Rieng Province, near the border with Vietnam. A consortium led by Sunseap, a solar developer from Singapore, has won the ICB bid with a tariff of US$0.091/kWh**.** According to Press reports, this project has already signed a 20-year PPA with EdC.

Global Purify Power (GPP), a Phnom Penh-based developer backed by a group of Southeast Asian investors, has started building the first 15 MW phase of a planned 225 MW solar rollout in Cambodia (to be installed at an industrial park in Kampong Speu province). According to Press reports, the total cost of the project is about US$400 million, which works out at some US$1,780/kW – which is quite high by recent reports of PV project prices.

EDC's 100 MWp solar power park program will be implemented in two phases, a first phase of 30 MWp to be followed by a second phase of 70 MWp.[13] This will be supported by ADB's Office of Public-Private Partnership, which will develop a feasibility study for the project, develop a bankable PPP structure, and organize a competitive tender process to select a suitable private sector sponsor for the power generation. ADB is expected to provide concessional funds to EDC for the common infrastructure of the solar park, including climate finance from the Climate Investment Funds administered by ADB.

Technical Issues

General Design Considerations for Floating Structures

The design considerations for a floating structure may be grouped into: (1) elements that satisfy the ***structural requirements*** that address the operating conditions, structural strength, serviceability, durability and safety standards; and (2) ***socio-political criteria*** that address the aesthetics, environmental sustainability, budgetary and legal constraints (Damodaran, 2017). The calibration of a design response to these considerations will determine an appropriate design life that caters to

13 https://www.adb.org/news/adb-partner-cambodia-launch-national-solar-park-program

the importance of the structure and environmental loads (at least 25 years for floating PV systems), preferably with a low maintenance cost.

The analysis and design of floating structures requires some special consideration when compared to land-based structures (Tradingeconomics.com, 2017; Electricity Authority of Cambodia, 2016):

i. Horizontal forces due to waves are generally several times greater than the (non-seismic) horizontal loads on land-based structures and the effect of such loads depends upon how the structure is connected to the reservoir floor. A rigid mooring system virtually prevents the horizontal motion while a compliant mooring will allow maximum horizontal motions of a floating structure of the order of the wave amplitude.

ii. In a floating structure, the static self-weight and payloads are carried by the buoyancy force of the water body. As such, there is no need for vertical supporting foundation as opposed to land-based structures. However, the mooring system has to be carefully designed to keep the floating structure in position even if the forces in the mooring system are small. This is due to possible displacement arising from slow-drift wave forces as well as steady current and wind forces. If a floating structure has a compliant mooring system, such as catenary chain mooring lines, the horizontal wave forces are balanced by inertia forces. Where the horizontal size of the structure is larger than the wave length, the resultant horizontal forces will be reduced given that different phases (direction and size) of the wave force will act on various parts of the structure, resulting in smaller forces in the mooring system relative to the total wave force.

iii. Sizing of the floating structure and its mooring system depends on its function and also on the environmental conditions, such as waves, current and wind. The design may be dominated either by peak loading due to permanent and variable loads or by fatigue strength due to cyclic wave loading. Moreover, it is important to consider possible accidental events such as boat impacts and to ensure that the overall safety is not threatened by a possible progressive failure induced by such damage.

iv. Possible degradation of the float materials (mostly HDPE) or crack growth (fatigue) requires a proper system for inspection, monitoring, maintenance and repair during use.

Materials

The majority of the floating platform materials used for floating PV is HDPE, which is strong, durable, light and UV resistant, and hence very suitable for long-term use. HDPE is also popularly employed in docks, jetties, parking space for private boats and jets, and walkways.

Mooring Systems

A mooring (or station keeping) system is used to secure a floating structure by keeping it in position under wave and other dynamic actions like drift. Mooring prevents horizontal movements and, to a certain extent, vertical motion. The effect of mooring systems on hydroelastic behavior of floating structures has been frequently analyzed. Operating conditions and environmental factors such as waves, wind forces and depth determine the type of mooring system to be chosen. The most common types of mooring methods include chain/cable, mooring pile, etc.

Extreme Storm Events (i.e. wind load, waves, extreme precipitation, or passage of hurricanes)

Many floating PV platforms are designed taking into account high wind load situations. Some of the suppliers have tested their design in wind tunnel testing. For example, Ciel et Terre International has tested their product C&T Hydrelio® at ONERA (the French aerospace lab), which is designed to withstand up to 210 km/h (≈58.3 m/s) winds (Osborne, 2017). In addition, projects can be specifically studied and further adapted to deliver even higher system wind-resistance.

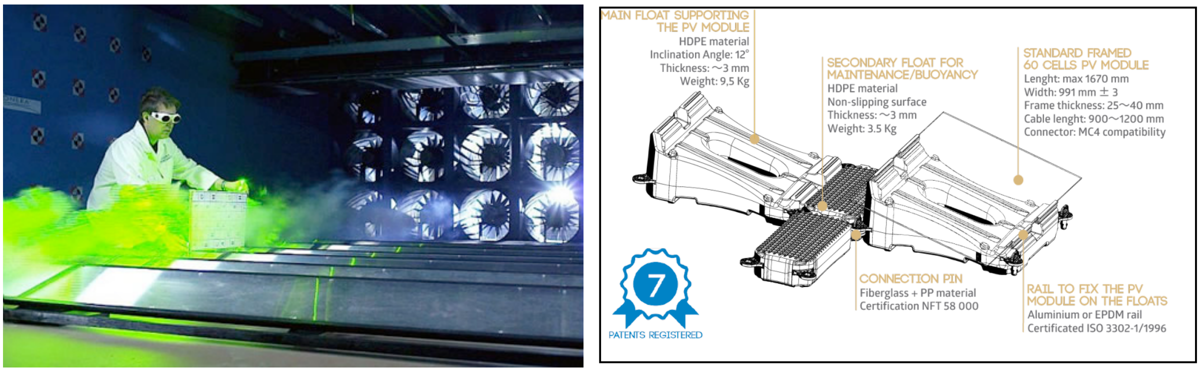


Figure 10-18. (Left) Laser tomoscopy in wind tunnel L2 (Lille) to test the wind resistance of solar panels intended to equip the first "industrial" floating photovoltaic power plant in the world, near Tokyo (Ciel et Terre Company). (Right) The design of Ciet et Terre (C&T) Hydrelio ®.

The floats designed by Sumitomo Mitsui Construction Co., Ltd. have passed similar wind tunnel testing at its Mitsui Sumitomo Construction Wind Tunnel Testing Building.

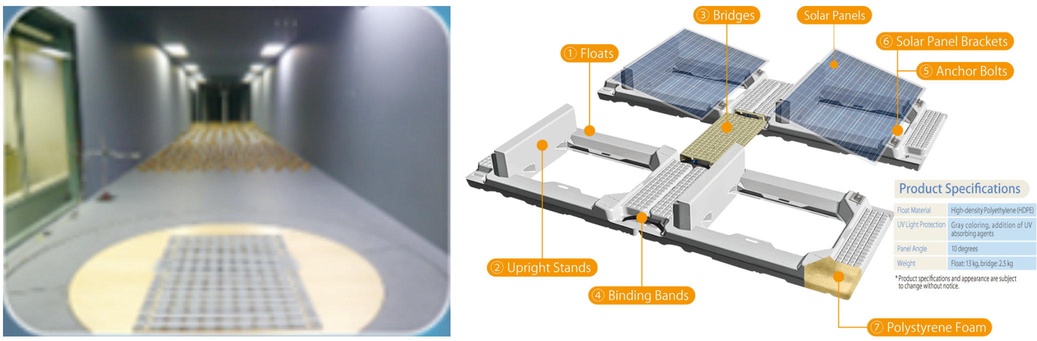


Figure 10-19. The floating platform design from Sumitomo (SMCC). The model has been tested in the Mitsui Sumitomo Construction Wind Tunnel Testing facility.

The one recorded incident where one of the largest-scale floating solar power plants in Japan was damaged by strong winds and high waves was caused by Typhoon No 9, on 22 August, 2016. According to the data of the Japan Meteorological Agency, a maximum instantaneous wind speed higher than 20m/s was recorded in the southern area of Saitama Prefecture. In total, 152 panels (41.8kW) were damaged by strong winds and high waves.

The floating platforms in question were those of the French Company C&T Hydrelio®, which in principle should survive a designed wind load of up to 210 km/h (≈58.3 m/s), as mentioned earlier. The possible causes for the observed damage are:

i. Anchor points were not at the perimeter floats, but a few rows inside the floating island,

ii. The perimeter floats were installed with PV modules, which capture the up-lift forces. (in the standard configuration of C&T system, the perimeter of the floating platform does not have PV modules and should be left empty),

iii. The water level was about 1 meter higher than designed water height, i.e. larger waves.

Figure 10-20. The damaged floating PV system, with its west "rim" turned over by strong winds and high waves. (source: Nikkei BP).

Engineering solutions can prevent such incidents, including proper civil and structure design and calculation for the mooring system.

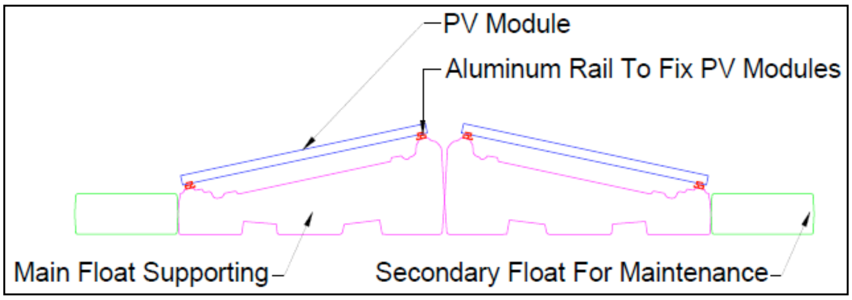


Figure 10-21. Dual-pitch configuration, as a solution to reduce wind load on floating PV modules / systems.

In addition, designs which reduce the up-lift forces of PV modules can be considered. For example, plates can be laid out behind panels to prevent strong winds blowing in from behind the panels. This is similar to that used for some ground-mounted or rooftop PV systems. C&T Hydrelio® also has a dual-pitch configuration as shown in Figure 10-21, which can be applied in low latitude tropical regions.

Ibiden Engineering has designed floating PV mounting system (Figure 10-22) with weights around the perimeter floats (Fu *et al.*, 2017). In particular, the floating components along the outermost edges contain water and are used as weights (also tilted and remains in the water). They prevent floats rising due to strong winds.

Figure 10-22. Ibiden's Floating Solar Mounting System.

Figure 10-23 shows the historical records (trajectories and categories) of tropical storms in Asia Pacific over the past 50 years (1956-2006). It can be observed that Cambodia is well "hidden" behind Vietnam, where the wind speed will decrease rapidly once a storm reaches land. The roughness of the land terrain increases friction, but more importantly, once over land, the storm is cut off from its heat and moisture sources. Thus, Cambodia is rarely under the strong influence of tropical storms.

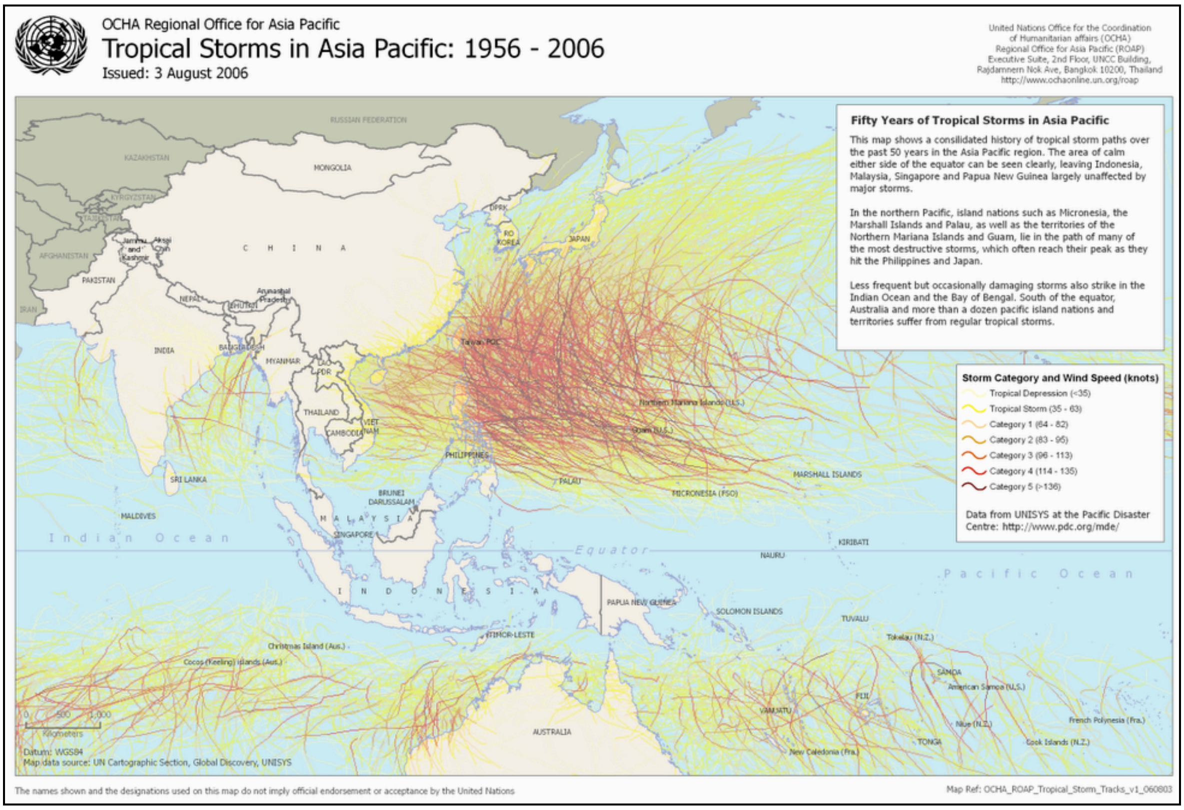


Figure 10-23. Historical records (paths and categories) of tropical storms in Asia Pacific over the past 50 years (1956-2006).

MRCS wind speed data from Kratie over two years 2007 and 2008 show a maximum wind speed of 25m/s.[14] However, the dataset is not long enough to make conclusions of max wind speeds on the LSS2 reservoir, especially when typhoons pass the from the Pacific (see Text Box 10-1). The historical wind speed data in Phnom Penh (Figure 10-24) suggests that the highest wind speed is 28-38km/h (or 7.8-10.6m/s)[15]. Although these values are sustained wind speeds, instead of gust wind speed (which needs to be considered for the mooring system design), they are well within the designed wind load ranges for floating platforms.

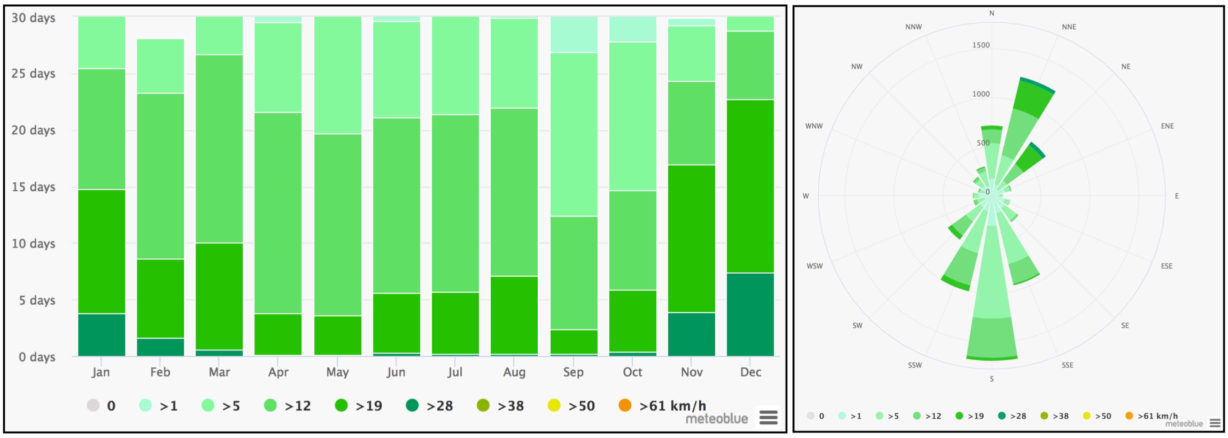


Figure 10-24. Wind Speed and Wind Rose diagram for Phnom Penh

If ground-mounted PV systems are considered, the flooding risks need to be properly assessed depending on the project site under evaluation. Based on the elevation map and flood extent map in Figure 10-25, it seems that the area at LSS2 is not under major flooding impacts. Nevertheless, for floating PV system, the impact on the floating platform and mooring system due to the increased flow rate in the river needs to be carefully analyzed and considered during the final design, especially during the wet season.

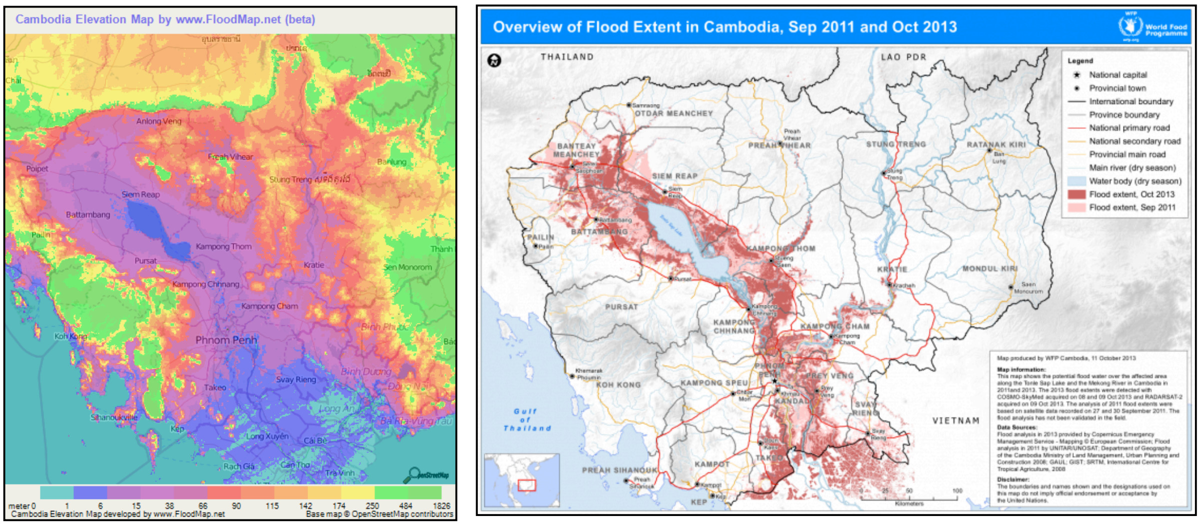


Figure 10-25. Cambodia elevation map and the overview of Flood Extent in Cambodia (Sep 2011 and Oct 2013).

14 MRCS: Mekong River Commission Secretariat, HydroMeteorological data.

15 Note that this wind speed data is typically measured at a height of 10 meters above the ground, and thus effectively higher than the wind speed on ground.

Text Box 10-1. Lessons of Typhoon Ketsama, 2009.

Typhoons from the Pacific passing the Philippines and making landfall in Vietnam can cross the Annamite mountain range between Lao PDR/Cambodia and Vietnam. The landfall in Vietnam and the mountain crossing however weakens the typhoon, degrading it to a tropical storm with lower windspeeds, but often still providing heavy precipitation.

On September 23, 2009, the Japan Meteorological Agency (JMA), reported a seasonal tropical depression had formed about 860 km to the northwest of Palau. Developing into a typhoon called Ketsana, maximum winds were reported at 167 km/h with gusts as strong as 204 km/h as it crossed over the South China Sea and approached land.

Track of the Ketsana typhoon, 2009.

It was downgraded to a Tropical Depression (17.5 m/s to 32.5 m/s) when the center of the depression was located over Southern Lao PDR, see fig 2. The weakening typhoon struck northeastern Cambodia as one of the most severe storms ever to lash the country, with the worst damage in Kampong Thom Province in central Cambodia. Although the flood runoff from Ketsana had little impact on water levels in the Mekong, the levels of the Sre Pok, Se San and Se Kong rose very rapidly in response to extreme flash flood runoff. At the Veunsai gauge on the Se San, levels rose by 4.5 m between the 29th and 30th September. In Thailand, three dams in Chai-ya-poom were damaged by the heavy rainfall, while in Pattaya waves reported to be over two meters high

It is therefore necessary to provide proper foundation for a floating PV installation to provide adequate protection against wind, waves, currents and flooding/flashfloods.

Degradation Rate of Tropical PV Systems

As of now, there are no sufficient records yet for the degradation rates for floating PV system, e.g. dual-glass modules vs. traditional framed modules.

Best practices can be recommended, such as 1) selection of PID-free PV modules, 2) utilize anti-corrosion module frames, supporting structures, electrical AC/DC combiner boxes, inverters, etc., and, if necessary, the application of additional anti-corrosion coatings on key components and electrical boxes, 3) select PV module junction boxes with good IP ratings[16], and 4) carefully design the cable routing, making sure that solar cables and especially connectors do not get submerged in water, which is often due to the constant movement of the floating platform.

[16] IP (Ingress Protection) is a measure of how good the junction box is protected against water and dust. A high IP rating will ensure that it is well protected against water ingress. Module junction boxes come with IP 65 or 67 rating. An IP 67 rating usually guarantees a very high level of protection against both these elements.

Issues with Bird Droppings

Floating PV arrays are often located on large area of water bodies, such as reservoirs or dams, therefore they become colonies and resting places for migratory and resident birds. Bird droppings are thus very often observed on floating PV modules, which cause partial shading. This leads to reduced energy output, as well as hot spots due to reverse bias of the shaded solar cells. In the long-term, this may lead to more permanent degradation of the solar cells and modules. In addition, if not cleaned regularly, bird droppings may also etch the front glass (Flicker, J. *et al*., 2012).

Figure 10-26. Bird droppings situation as observed at the floating PV systems at Queen Elizabeth II reservoir

Figure 10-27. Bird droppings situation as observed at the Singapore floating PV Testbed.

Potential solutions to the problem of bird droppings include, barriers, visual scare devices, ultrasonic repellers, recorded alarm calls, and laser devices[17]. For example, a laser system called Agrilaser Autonomic scares birds by moving a harmless laser beam over an area of up to 500 acres. It was successfully deployed on the floating PV systems at Queen Elizabeth II Reservoir in UK (Figure 10-26), to keep a population of more than 10,000 black-headed gulls from using the plant as a roosting site. As a result, the electricity production increased significantly after its deployment.

[17] Solving the problem of bird soiling on PV plants. https://www.solarplaza.com/channels/asset-management/11730/solving-problem-bird-soiling-pv-plants/.

Up-scaling of Floating PV Systems

The up-scaling of floating PV system does not seem to be an issue, due to the modular nature of PV systems in general. Table 10-8 lists the largest floating solar PV projects worldwide.

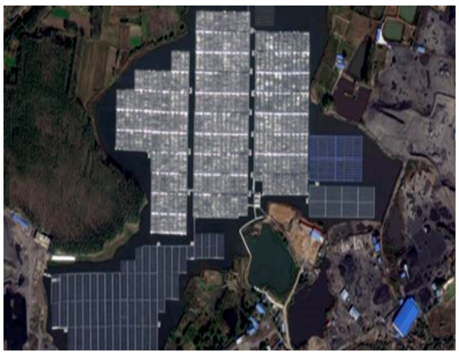
Table 10-8: Top 15 floating solar PV plants worldwide.

Rank	Size (kw)	Name of reservoir (lake) / Name of Plant	Country	City/Province	Operating from
1	**40,000**	Coal mining subsidence area of Huainan City	China	Anhui Province	April, 2016
2	**20,000**	Coal mining subsidence area of Huainan City	China	Anhui Province	April, 2016
3	**7,500**	Kawashima Taiyou to shizen no megumi Solarpark	Japan	Saitama	October, 2015
4	**6,338**	Queen Elizabeth II reservoir	UK	London	March, 2016
5	**3,000**	Otae Province	South Korea	Sangju City Gyeongsang Bukdo	October, 2015
6	**3,000**	Jipyeong Province	South Korea	Sangju City Gyeongsang Bukdo	October, 2015
7	**2,991**	Godley Reservoir Floating Solar PV	UK	Godley	January, 2016
8	**2,449**	Tsuga Ike	Japan	Mie	August, 2016
9	**2,398**	Sohara Ike	Japan	Mie	March, 2016
10	**2,313**	Sakasama Ike	Japan	Hyogo	April, 2015
11	**2,000**	Reservoir in Kumagaya city	Japan	Saitama	December, 2014
12	**2,000**	Kinuura Lumberyard	Japan	Aichi	February, 2016
13	**2,000**	Yado Ooike (Sun Lakes Yado)	Japan	Hyogo	January, 2016
14	**1,751**	Hirono Shinike	Japan	Hyogo	September,2016
15	**1,708**	Yakenoike	Japan	Hyogo	July, 2016

40MW, Huainan, Anhui, China

8MW, Lingxi lake, Linxi, Hebei

8.5MW, Sanshan, Wuhu, Anhui



Coal mining subsidence area,

SERIS has visited the Sungrow 40 MW floating PV farm, which is currently the largest floating PV system. SERIS is also involved in another 150 MW floating PV project in China, which will be partially grid connected by 2017. The scale of such floating PV projects is increasing rapidly. Due to the modular nature of PV in general, there should be no major issue with up-scaling. However, there may well be an upper limit for how large one individual floating island can be, due to internal stresses among the floats and interlocking. However, PV projects can be built modularly by basic unit blocks.

The 40 MWp Sungrow project was built as 16 units of 2.5 MW floating arrays. Each floating array has standardized design, with 2,500 kVA inverter + transformer and 3MWp PV Array (1.2 DC-AC ratio) (see Figure 10-28 and Figure 10-29). Due to the size of the floating PV, LV/MV stations need to be in the middle of the array to avoid excessive cable losses (rather than placement on land).

Figure 10-28. The standardized design for Sungrow floating PV system, with unit floating array block of 2.5MWac. The central inverter, switch gear and transformer are containerized and located in the middle of the floating array unit.

Figure 10-29. Basic building block of Sungrow floating PV arrays, with 2 units of 2.5MWac.

As an alternative to a floating central inverter, string inverters can also be mounted directly on the floating platform, right next to the PV modules (leaving sufficient space to avoid shading). For example, Huawei's string inverter is designed with passive cooling (without fan), thus the entire casing is IP65 and suitable for direct installation on water. For large size floating arrays, similar to the electrical configuration showed in Figure 10-28 string inverters and AC combiner boxes can be placed on the floating platform (Figure 10-30), and then centrally stepped up and connected to the nearby substation.

Figure 10-30. Floating Smart PV Plant, Kasai-shi, Hyōgo, Japan, where string inverters are mounted directly on the floating platform.

In early 2017, a hybrid system combining floating photovoltaics and hydroelectric power generation was at the Alto Rabagão dam in Portugal (Figure 10-31). The system has an installed capacity of 220kWp, with 840 floating PV panels. The significance of this project is in its mooring system, which needs to cope with the reservoir depth of 60m and a water level variation of 30m (Osborne, 2017).[18]

Figure 10-31. 218 kWp C&T, at Alto Rabagão dam, Portugal. Source: Moody's, 2017.

18 This water level variation far exceeds that likely to be encountered at low head projects in the LMB. At LSS2, the active storage is entirely contained within one meter of reservoir elevation.

Power Evacuation

The addition of floating PV at LSS2 will need to take into consideration potential limitations in: (i) the capability of the Cambodian power system spinning reserve capacity to respond to the intermittency of PV power generation; and (ii) the evacuation capability of the respective 230 kV interconnection and 230kV grid transmission lines that tie the LSS2 power station into the North Phnom Penh (NPP) substation located about 300km away in the main load center at Phnom Penh city (Figure 10-32).

Cambodia's Power System Planning

By 2020, The Cambodia Power system is expected to be interconnected with Thailand, Vietnam and Laos, although the means of interconnection between the much larger asynchronous systems of Vietnam and Thailand have yet to be determined. Currently the 400 MW Phnom Penh system is synchronized with Vietnam to which the LSS2 will also be connected. We understand that the southern Laos system is synchronized with Thailand and therefore unlikely to be connected to Stung Treng Substation in the short term.

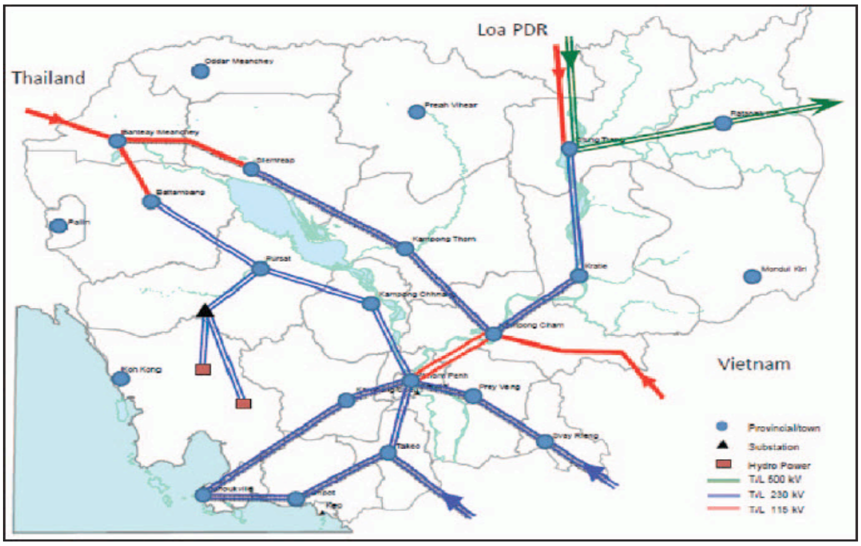


Figure 10-32: Transmission system interconnections. Source: Global CCS Institute, 2017.

Intermittency of Floating PV Installation

The saw-tooth pattern of solar power output due to cloud movements creates a significant complication for grid integration of large scale PV systems. The ability of the hydro turbo-generator sets at LSS2 to quickly adjust to changes in the solar power output depends on the design of the turbines and associated excitation/governor facilities. Turbines with adjustable blades or that can otherwise respond quickly to changes in solar power output can help smooth out combined output of hydro + PV and provide the desired ramp rate required by the grid. If the LSS2 bulb turbines are not as flexible as vertical axis turbines, it may be necessary to use fast acting storage facilities (e.g. batteries or flywheels) to ensure that the PV ramp rate is within acceptable limits of the grid's spinning reserve capability.

Spinning Reserve Capability of Cambodian Power System

The capacity of the Cambodian power system to absorb PV fluctuations from the proposed LSS2-Hydro/PV installation will be determined by the relative size of the Cambodian power system, the makeup of the power plants, including other intermittent sources of generation, and the capability of the interconnections with the much larger power systems in Vietnam and Thailand. If, as expected, the interconnections with Thailand and Laos are via back-to-back HVDC substations, these will be able to provide significant technical benefits in smoothing the more rapid generation changes associated with the intermittency of PV production. Thus, the absorptive capacity of the Cambodian grid system will improve from year to year according to the largely coal fired thermal and other hydro generation that is installed to meet the demand forecast, along with the number of transmission interconnections to neighboring systems.

However, regardless of the pace of such interconnection, beyond 2020 there should be hydro and thermal capacity installed sufficient to ensure that the main load center in Phnom Phen is capable of managing rapid changes in output from the LSS2-PV solar plant. Moreover if the proposed transmission interconnection is made to Vietnam directly from LSS2 or alternatively through the Laos (presumably via an HVDC back-to-back facility) system, reserve capability should be more than adequate to handle fluctuations of at least 10% of the combined LSS2 Hydro-PV output. To determine the magnitude and timing of installation, and exactly how much intermiitent capacity of PV can be installed, will require a detailed technical study using PSS/E or equivalent facilities.

Evacuation Capability of the 230kV Transmission Lines

The 2014 JICA/Newjec Report indicates that the LSS2 power station was intended to be connected to the 230 kV Stung Treng grid substation by a 36km double circuit 2*400mm^2 ACSR 230kV line. From Stung Treng the output of the LSS2 would be expected to flow about 300 km through a 2*620mm^2 ACSR 230 kV double circuit line supplying Phnom Penh North (NPP). That grid line will essentially determine the capability the LSS2 power evacuation system[19].

The JICA/Newjec report also provides nominal MVA ratings for the respective transmission lines, although the manufacturing details of the conductors and the environmental conditions used to determine the ratings are not specified. As noted in Table 10-9, conductor current ratings can vary as much as 100% between best conditions (i.e. low ambient temperatures, light winds) and worst conditions (i.e. high temperatures, no wind). As explained below transmission constraints may be a problem for the short 32 km interconnection between LSS2 and the Sung Treng substation. On the other hand, it is unlikely that constraints will be a problem for the longer 230 kV grid lines. In this case, capacity will probably be limited by voltage conditions at substations en route (as noted above).

[19] Details of the planned 230kV transmission lines can be found in the Tables of the report *Preparatory Survey for Phnom Penh it transmission and Distribution System Expansion Project, Phase II*, Dec 2014 JICA/Newjec

The short Transmission Interconnection from LSS2 to Sung Treng Substation

According to the JICA/Newjec report, the interconnecting LSS2-Stung Treng ACSR 2*400mm^2 230kV line is capable of carrying a full load rating of 2*604 = 1200 MVA i.e. with both circuits fully loaded. However as shown in Table 10-9, the current ratings for this conductor type vary considerably depending on the prevailing environmental conditions. The current ratings reported above are based on a conservative maximum conductor temperature rating of 75^{o}C. On a still hot summer day, the current ratings could be increased by about 35% if a higher conductor temperature is allowed (typically 90^{o}C), depending in conductor sag limitations.[20]

Table 10-9. Transmission line ratings based on IEEE 738-2012.[21]

		Dry Season				Wet Season			
Environmental Parameters		Still Day	Windy Day	Still evening	Windy evening	Still Day	Windy Day	Still evening	Windy evening
Ambient Temp	^{0}C	37	37	25	25	30	30	30	30
Conduct Temp	^{0}C	75	75	75	75	75	75	75	75
Wind Speed	m/s	0	3	0	3	0	1	0	1
Wind Angle	Degree	0	90	0	90	0	90	0	90
Emissivity ἐ		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Solara Absoptivity α		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Elevation	m	0	0	0	0	0	0	0	0
Solr & Sky radiated heat	W/m^2	1200	1200	0	0	800	800	0	0
Angle of incidence	W/m^2	90	90	90	90	90	90	90	90
Transmision Line ratings for Combodia Transmission Lines									
Rating 620mm2 [A]		635	1523	1005	1869	820	1246	948	1334
230kV Trans MVA		506	1212	800	1487	652	991	754	1061
Rating 400mm2 [A]		488	1184	764	1446	626	970	720	1033
230kV Trans MVA		389	942	608	1151	498	772	573	822

To allow for one circuit to be taken out of service, a typical transmission line would be nominally rated to meet an "n-1" reliability standard[22] on the basis of one circuit in operation i.e. in this case 604 MVA. However, the interconnecting line is relatively short, unconstrained by voltage regulation issues, and unlikely to be exposed to as many weather related or other interruptions as compared to the longer main grid lines.

The LSS2 hydro power station is rated at 400 MW which translates to about 500 MVA at a 0.8 power factor. Thus, if the floating PV facility is in operation at the same time as hydro, one circuit of the short 36 km 230 kV line interconnector could normally carry another 100 MW of PV generation even at the nominal n-1 rating. If it turns out that the operational mode of the combined hydro/PV system generates significantly larger peak power flows for prolonged periods on a frequent basis, then there may well be a case for building the third 36km 230kV single circuit line for about $10m

[20] In most cases where the peak is in the evening when there is no contribution from the PV facility, this may not present a problem for generation scheduling. However, in Cambodia, in recent years the main EdC peak has been observed at around 15:00 (see Figure 10-34)

[21] 738-2012 - IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors: A standard method of calculating the current-temperature relationship of bare overhead lines, given the weather and both constant and variable conductor current conditions.

[22] "n-1" is a crude, by widely used proxy for the reliability of transmission system – indicative of the desirability that a given transfer cab be accommodated even if one circuit has failed.

(an issue assessed below in the PSSE studies). This is a very small cost compared to the $400 million for a 400MW scale solar project itself.[23]

Table 10-10: Cambodian Transmission Line Planning Data.

Cambodia Transmision Lines - Listed IN JICA/Newjec Study Dec 2014								
	Existing Lines 2014	Voltage	Length			Capacity	Operation	
From	To	[kV]	[km]	Circuit	Conductor	[MVA/cct]	Year	Owner
West Phnom Penh	Takeo	230	46	2	ACSR 632	430	2008	EDC
Takeo	Vietnam Border	230	50	2	ACSR 400	302	2008	EDC
Takeo	Kampot	230	73	2	ACSR 400	302	2012	EDC
Kamchay Hydro	Kampot	230	11	2	ACSR 400	302	2012	EDC
West Phnom Penh (GS4)	Kampong Chhnang	230	88	2	ACSR 632×2	861	2012	CPG
Kampong Chhnang	Pursat	230	83	2	ACSR 632×2	861	2012	CPG
Pursat	Battambang	230	122	2	ACSR 632×2	861	2012	CPG
Pursat	O'soam	230	132	2	ACSR 632×2	861	2012	CPG
Kampot	Sihanoukville	230	82	2	ACSR 632	430	2013	EDC
Sihanoukville	Stueng Hav Thermal	230	-	2	-	-	2013	BOT
North Phnom Penh (GS6)	Kampong Cham	230	97	2	ACSR 632×2	861	2013	CTL
South Phnom Penh (GS7)	West Phnom Penh (GS4)	230	24	2	ACSR 632×2	861	(2014)	EDC
Stung Tatay	O'soam	230	65	2	ACSR 400	302	2014	BOT
Lower Russey Chrum								
(upper 87 MW×2)	O'soam	230	32	2	ACSR 400	302	2014	BOT
	Planned Lines 2014	Voltage	Length			Capacity	Operation	
From	To	[kV]	[km]	Circuit	Conductor	[MVA/cct]	Year	Owner
Lower Russey Chrum	O'soam	230	40	2	ACSR 400	302	2014	BOT
(lower 82 MW×2)								
Stung Treng	Kratie	230	85	2	ACSR 632×2	861	(2015)	EDC
Kampong Cham	Kratie	230	140	2	ACSR 632×2	861	(2015)	LYP
Stung Treng	**Lao**	230		2	ACSR 632	430	(2016)	EDC
West Phnom Penh (GS4)	Sihanoukville	230	-	2	ACSR 632×2	861	(2016)	CHMC
Stung Treng	**Lower Sesan2 Hydro**	230	36	2	ACSR 400×2	604	(2017)	BOT
Sre Ambil	Koh Kong	230	-	2	-	-	(2018)	-
North Phnom Penh	Chhay Areng Hydro	230	-	2	-	-	(2018)	-
Chhay Areng Hydro	O'soam	230	-	2	-	-	(2018)	-
Koh Kong	O'soam	230	-	2	-	-	(2019)	KTC
Chay Areng Hydro	Chamkar Luong	230	-	2	-	-	(2019)	EDC
GS1	GS3	115	11.3	1	AAC 250×2	238	2000	EDC
GS3	CEP	115	5.0	1	AAC 250×2	238	2009	EDC
CEP	GS2	115	7.0	1	AAC 250×2	238	2009	EDC
GS2	KEP	115	6.6	1	AAC 250×2	238	2009	EDC
KEP	Old GS4	115	14.3	1	AAC 250×2	238	2009	EDC
Old GS4	SWS (GS5)	115	21.4	1	AAC 250×2	238	2009	EDC
GS5	GS1	115	5.3	1	AAC 250×2	238	2009	EDC
Old GS4	GS4	115	10.3	2	ACSR 632	215	2009	EDC
GS5	Kampong Speu	115	40.9	2	ACSR 150	85	2000	EDC
Kampong Speu	Kirirom1 hydro	115	65.2	2	ACSR 150	85	2000	EDC
Kirirom1 hydro	Kirirom3 hydro	115	38.0	2	ACSR 150	85	2012	EDC
Stung Atay(1st 20 MW)	Stung Atay(2nd 100 MW)	115	15	1	ACSR 150	85	2012	BOT
Stung Atay (2nd 100MW)	O'soam	115	8	2	ACSR 500		2012	BOT
SPP (GS7)	GS2	115	16.4	2	ACSR	-	(2014)	EDC
GS5	NPP (GS6)	115	24.8	2	ACSR	-	(2014)	EDC
Thai Border	Industrial Estate GS	115	4.0	1	AAC400	-	2007	CPTL
Industrial Estate GS	Banteay Meanchay	115	43.0	1	AAC400	-	2007	CPTL
Banteay Meanchay	Siem Reap	115	85.0	1	AAC400	-	2007	CPTL
Banteay Meanchay	Battambang	115	53.0	1	AAC400	-	2007	CPTL
SPP (GS7)	Neak Loeung	115	-	-	-	-	(2016)	CHMC
Neak Loeung	Svay Rieng	115	-	-	-	-	(2016)	CHMC
* ACSR	Aluminum Conductor Steel Reinforced		* ACSR/AC	Aluminum Conductor Aluminum Clad Steel Reinforced				
* AAC	All Aluminum Conductor							
* LYP	Ly Yong Phat Group		* CPG	Cambodian Power Grid Co., Ltd.				
* CHMC	China National Heavy Machinery Corporation		* CTL	Cambodian Transmission Limited				
* KTC	:KTC Cable Co., Ltd.		* CPTL	Cambodian Power Transmission Line Co., Ltd.				

23 This cost has therefore been added to the PV implementation scenario considered in Chapter 11.

Main Grid Supply to Phnom Penh

As shown in Table 10-10, the main grid ACSR 2*620mm^2 230 kV grid line sections comprise: Stung Treng-Kratie (140km), Kratie-Kampung Klam (97 km), and Kampung-Klam-North Phnom Penh (85 km) all of which are nominally rated at 861 MVA per circuit. Power flow along this 320km grid line will be largely constrained by 230 kV voltage regulation issues - which if necessary can be mitigated by installing additional reactive compensation or STATCOM[24] facilities at one or more of the 230 kV substations en route, again as discussed in the next section.

Power Systems Studies

As noted, PV output power fluctuations caused by moving clouds may adversely affect the power system stability, especially in underdeveloped grids like in Cambodia. Deploying floating PV on LSS2 reservoir aims to smooth the PV fluctuations by adjusting the hydro turbines to increase or decrease output from the existing station. However, the effectiveness of this concept is subject to the dynamic performance of the hydro units and reservoir storage capability.

The purpose of the PSS/E study is to identify the optimum sequence of increasing floating PV investment and the associated cost, if any, to evacuate power without disturbing the power system. The associated cost implications could be: (1) transmission line upgrades; (2) additional reactive compensation devices; and (3) additional energy storage systems.

The detailed electrical parameters of the LSS2 hydro turbine-generators and the Cambodia grid information have not been provided to us. The study was therefore carried out with generic parameters available in the PSS/E software. However, to move from proof-of-concept as provided in this NHI report to a formal pre-feasibility study suitable for presentation to potential sponsors and funders of a full feasibility study, additional information will be needed for a comprehensive understanding of the impact of variable PV output power based on the electrical performance of the actual units installed at LSS2.

Two onerous PV fluctuation scenarios were analyzed to test the system ramp-up and ramp-down performance:

- **Ramp-down**: the solar PV output power was dropped from 100% to nearly 0 within 5 seconds (from 5 seconds to 10 seconds in the simulation);
- **Ramp-up**: the solar PV output power was increased from 0 to 100% within 5 seconds (from 5 seconds to 10 seconds in the simulation).

The solar PV ramp rate tested in this study is 1pu/5sec[25], which represents an extreme worst condition for a MW-scale solar farm. Large scale solar farms spreading over a wide range of area will smooth out the output variations and show a relatively more moderate output ramp rate. The solar ramp rate recorded from Longyangxia project is around 1pu/15mins. Therefore, the simulation scenarios in the study represent the worst PV fluctuation condition.

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24 A static synchronous compensator (**STATCOM**), also known as a static synchronous condenser (STATCON), is a regulating device used on alternating current electricity transmission networks. If connected to a source of power it can also provide active AC power. It is a member of the FACTS (flexible AC transmission) family of devices.

25 A per-unit (pu) system is the expression of system quantities as fractions of a defined base unit quantity. In this case, the base unit quantity is the PV installed capacity.

Other key assumptions included:

(1) The study base year is 2020 when the first section of the floating PV plant is expected to be installed

(2) The grid information, such as demand forecast at Phnom Penh and the transmission lines parameters were taken from the JICA report. The power factor of load at Phnom Penh is assumed as 0.95.

(3) The grid under-frequency limit is assumed as **48.5Hz** for **3 sec** and over-frequency limit is **51.5Hz** for **3 secs**. Once the system frequency is beyond those limits, load shielding and generator tripping will be triggered in the real grid and the grid has the risk of losing stability.

(4) All the generation from solar PV will be fed into grid. The LSS2 hydro generation is maintained constant at a moderate output level of 300 MW before PV variations in all the cases. Existing reactive compensation on 230kV line is assumed to be 75 MVAr at Kampong Cham and 150MVAr at NPP For the base year.

(5) The complimentary operation algorithm of the LSS2 hydro unit and solar PV in steady state is not modelled in this study. The simulation study in this report represents only the extreme conditions during dry season or extreme high water flow conditions where the complimentary operation is ineffective, and the fast ramping solar PV variations need to be managed by the grid spinning reserves and additional Flexible Alternating Current Transmission System (FACTS)[26] and ESS facilities.

Figure 10-33 shows the simulation model setup in PSS/E. According to the system planning, the power generated at the hybrid LSS2 power plant will be transmitted to the load center at North Phnom Penh (NPP), the designated terminal grid substation in the simulation.

The LSS2 power plant is shown on the right hand-side of Figure 10-33, which consists of 8 x 50MW hydro units, the PV installation and an additional fast acting Energy Storage System (ESS) if it is found to be necessary. The resulting aggregate generation from LSS2 is fed into NPP through a ~300km 230kV transmission line. To simplify the analysis a constant load model is connected at NPP substation to represent the system peak load; along with a virtual coal fired thermal station and a hydro power plant to represent the dynamics of the rest part of the grid. Reactive compensation devices will also be needed at substations to maintain voltage stability on the 220kV line connecting LSS2 and NPP. The dynamic model parameters for each machine are presented in the detailed technical report (SERIS, 2017).

[26] A **flexible alternating current transmission system** (FACTS) is defined as "a power electronic based system and other static equipment that provide control of one or more AC transmission system parameters to enhance controllability and increase power transfer capability". In the project, it refers to the STATCOM.

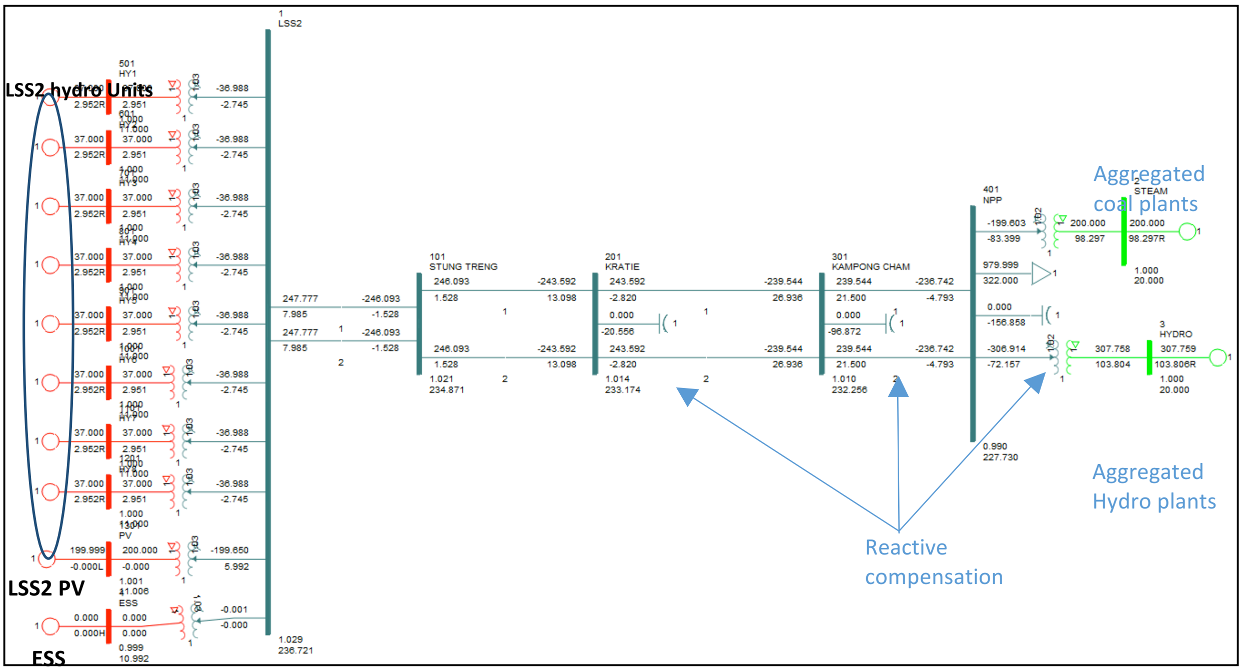


Figure 10-33. Simulation model setup.

Results

The results of this analysis are shown in Table 10-11 and Table 10-12 for the ramp down cases. The solar PV power is ramped down from 1pu to 0 in 5secs. During steady state, solar PV output power is 1pu. Different solar PV deployment plans have been tested and detailed simulation results can be sighted in SERIS (2017).

Table 10-11: Summary of results: Ramp-down case, 2020.

	2020 Base case 100MW@LSS2	2020 high PV 200MW@LSS2	2020 Extreme PV 300 MW @LSS2
Peak load at NPP (MW)	980	980	980
LSS2 Hydro (MW)	37*8=300	37*8	37*8
LSS2 PV (MW)	100	200	300
Coal plant (MW)	200	200	200
Hydro plant (MW)	400	300	200
Load Flow: reactive compensation (MVar)	75Mvar Cap @Kampong Cham; 155Mvar Cap @ NPP	20MVAr Cap @Kratie; 95Mvar Cap @Kampong Cham; 160Mvar Cap @ NPP	70MVAr Cap @Kratie; 140Mvar Cap @Kampong Cham; 160Mvar Capacitor banks @ NPP
Dynamic response	Stable. Frequency nadir is 49.5Hz.	Stable. Frequency nadir is 49.05Hz.	Frequency nadir is 48Hz. Frequency below 48.5Hz for 4.81secs. After PV fluctuation, over-voltages are seen in Kratie and Kampong Cham due to high cap banks.
ESS	None	none	None
Improvement measures	none	none	83.8 MW ESS is required to improve system stability. Manually switched capacitor banks are not capable to maintain reasonable voltage. Suggest to use STATCOM at Kratie and Kampong Cham for reactive power compensation. STATCOM can auto-adjust its output according to system condition.

Table 10-12: Summary of results: Ramp-down case, 2022-2025.

	2022 base case	2020 high PV	2025
Peak load (MW)	1205	1205	1543
LSS2 Hydro (MW)	37*8	37*8	37*8
LSS2 PV (MW)	200	300	300
Coal plant (MW)	300	300	400
Hydro plant (MW)	400	300	580
Load Flow: reactive compensation (Mvar)	25MVAr Cap @Kratie; 100Mvar Cap @Kampong Chan; 230Mvar Cap @ NPP	70MVAr Cap @Kratie; 145Mvar Cap @Kampong Cham; 255Mvar Capacitor banks @ NPP	65MVAr Cap @Kratie; 160Mvar Cap @Kampong Cham; 400Mvar Cap @ NPP
Dynamic response	Stable. Frequency nadir is 49.25Hz.	Frequency nadir is 48.35Hz. Frequency below 48.5Hz for 2.93secs. After PV fluctuation, over-voltages are seen in Kratie and Kampong Cham due to high cap banks.	Stable. Frequency nadir is 49.15Hz. After PV fluctuation, over-voltages are seen in Kratie and Kampong cham due to high cap banks
ESS	None	None	none
Improvement measures	None	(1) very close to unstable; (2) Using STATCOM for reactive compensation	(1) Using STATCOM for reactive compensation

The analysis of the PV ramp-down scenarios permits the following observations:

- For year 2020, three different solar PV capacities were tested. During steady-state, with increasing solar PV power, loadings on transmission lines are higher and voltage drops along the lines are becoming severe. During PV ramp-down, the system retains stability in the base and high PV case. However, once the installed PV increases to 300 MW, the system will lose stability. At that level, additional 84 MW battery energy storage system should be installed at LSS2 to ensure system stability.

- For year 2022 and 2025, the system demands are increased. The system can maintain stability with 300 MW solar PV. No battery energy storage system is required for system stability improvement.

- During steady-state, additional capacitive compensation devices such as capacitor banks should be equipped at the intermediate substations, especially at Kratie and Kampong Cham. The higher the transferred power, the more compensation devices are required. However, after sudden PV ramp-down, as the total transferred power from LSS2 is reduced, the grid should have the capability to reduce those compensation devices, otherwise over-voltages may happen at Kratie and Kampong Cham.

- To compensate for the frequent PV output variations, it is recommended to substitute some manually-switched capacitor banks with dynamic reactive compensation device, such as STATCOM at Kratie or Kampong Cham. STATCOM is able to maintain reasonable voltage level by regulating its output reactive power.

- With more than 200MW solar PV installed, the maximum power transferred from LSS2 to Stung Treng would exceed 600 MW, which is higher than the rating of the single transmission line from LSS2 to Stung Treng and the N-1 criterion will not be fulfilled for short periods. To secure the power integration from LSS2 power plant, it may be appropriate to add a further single circuit 230kV transmission line from LSS2 to Stung Treng.

Table 10-13 summarizes the simulation results from solar PV ramp-up scenarios. In this scenario, solar PV power is ramped up from 0 to 1pu in 5secs. During steady state, solar PV output is 0.

Table 10-13: Summary of results: Ramp-up case, 2020.

	2020 Base case 100MW@LSS2	2020 high PV 200MW@LSS2	2020 Extreme PV 300 MW @LSS2
Peak load at NPP (MW)	980	980	980
LSS2 Hydro (MW)	37*8	37*8	37*8
LSS2 PV (MW)	**100**	**200**	**300**
Coal plant (MW)	200	200	200
Hydro plant (MW)	400	300	200
Load Flow: reactive compensation (MVar)	35Mvar Cap @Kampong Cham; 140Mvar Cap @ NPP	35Mvar Cap @Kampong Cham; 140Mvar Cap @ NPP	35Mvar Cap @Kampong Cham; 140Mvar Cap @ NPP
Dynamic response	Stable. Max frequency is 50.55Hz.	Stable. Max frequency is 51.1Hz. over-voltage and under-voltage are seen at Kampong Cham, Kratie and NPP during dynamics	**Unstable.** Max frequency increase to 52.1Hz. Frequency above 51.5Hz for 8.66secs. System lose stability
ESS	none	none	none
Improvement measures	none	Using STATCOM to improve voltage stability	84.1MW ESS is required to improve system stability.

Table 10-14: Summary of results: Ramp-up case, 2022-2025.

	2022 base case	2020 high PV	2025
Peak load (MW)	1205	1205	1543
LSS2 Hydro (MW)	37*8	37*8	37*8
LSS2 PV (MW)	**200**	**300**	**300**
Coal plant (MW)	300	300	400
Hydro plant (MW)	400	300	580
Load Flow: reactive compensation (Mvar)	30Mvar Cap @Kampong Chan; 250Mvar Cap @ NPP	30Mvar Cap @Kampong Chan; 250Mvar Cap @ NPP	50Mvar Cap @Kampong Cham; 420Mvar Cap @ NPP
Dynamic response	Stable. Max frequency nadir is 50.85Hz. over-voltage and under-voltage are seen at Kampong Cham, Kratie and NPP during dynamics	Stable. Max frequency is 51.3Hz. over-voltage and under-voltage are seen at Kampong Cham, Kratie and NPP during dynamics	Stable. Max frequency is 50.95Hz. over-voltage and under-voltage are seen at Kampong Cham, Kratie and NPP during dynamics
ESS	none	None	none
Improvement measures	Using STATCOM to improve voltage stability	Using 100MVAr STATCOM+80MVar Cap banks to improve transient voltage profile	Using STATCOM to improve voltage stability

Additional observations for the ramp-up scenarios:

- The system dynamic performance during PV ramp-up is quite similar to PV ramp-down. The system loses stability in year 2020 with 300MV PV installed. Additional 84MW battery energy storage system would need to be installed to improve the system frequency performance. In other years, the system remains stable without energy storage.

- Voltage variations during PV ramp-up are more severe than for ramp-down. Over-voltage was seen at the initial stage of power ramp-up due to the excess reactive power from conventional generators. However, it was followed by under-voltage due to heavy loading on the transmission lines. To achieve dynamic voltage control, STATCOM should be installed at Kratie or Kampang

Cham. The simulation also shows that the size of STATCOM should be larger than for the PV ramp-down case.

Conclusions

We examined the dynamic performance of LSS2 hybrid solar and hydro power plant and the grid stability performance during sudden PV output fluctuations. However, all the studies in this report were performed with generic data assumed to represent the various parts of the power system, and the results cannot therefore be considered definitive and must be redone once the necessary LSS2-specific information becomes available. Nevertheless, we present a valid assessment for the concept of a hydro-PV hybrid operation: The methodology and approach developed in this study can be easily applied with actual project data. The study has also permitted the identification of the detailed information that will be required at the detailed FS stage.

The following conclusions can be reached for the Solar PV system at LSS2 that will affect the economic analysis presented in Chapter 11.

- The 3rd transmission line from LSS2 to Strung Treng, costing about US$10 million, will be required once the solar PV capacity exceeds 200 MW, under the assumption of a unity power factor at LSS2. If the reactive power generation from LSS2 is higher, then the requirement for 3rd transmission line will be required earlier. This is a very small incremental investment compared to the cost of the PV system itself (400 MW of PV will cost US$400 million).

- Due to the frequent PV fluctuations, manually-switched type reactive power compensation devices, such as capacitor banks, will not be adequate to maintain voltage stability. Dynamic reactive power compensation devices, such as a STATCOM, should be installed at Kratie (50MVar) and Kampang Cham (50MVar), costing US$50/KVar (US$5 million)

- Depending on the system spinning reserve capacity, the PV fluctuations may be fully absorbed by the grid and eliminate the requirement for a fast acting energy storage system. More detailed system dynamic studies with actual network and appropriate LSS2 generator data should be conducted to identify the optimized solar PV deployment plan.[27] For the time being we make the assumption that for every 10 MW of PV, 10 MW of ESS would be required, which we assume a cost of 950$/kW (De la Parra *et al.*, 2015).

Integrated Project Operation

The basic concept of integrating PV with hydro is that the hydro project serves as a giant battery to shift power production from the PV project from the hours in which it is necessarily produced, to the hours that the system most values the power during whatever are the peak hours of the day. This is easy to do for the hydro project alone, since water can be released at the command of the plant operator. In the best case, the system peak occurs during the peak sunshine hour of the day – but this is rarely so. In many countries, the traditional evening peak is beginning to shift into daytime hours as air conditioning loads increase, but there is rarely such fortuitous coincidence.

[27] Alternatively, it has been suggested that one might require 10 MW of flywheel storage per 100 MW of PV. At a cost of US$1500/kW this means a total cost of US$15 million per 100MW of PV. (At 1000$/kW, the PV installation for a 100MW tranche costs US$100 million). However, the world largest deployment of flywheel system so far is only 20MW/5MWh (15min discharging time), the experience of large-scale flywheel system is still limited, and an IPP may be hesitant to use this technology. In the short run Li-ion battery remains the mainstream product.

In fact, the EdC system has a somewhat unusual daily load curve, as shown in Figure 10-34, with three peaks: the first at around 10 am, the second around 2 pm, and a slightly lower evening peak around 7 pm. In 2014, these peaks were around 600 MW, as against the off-peak night time load of around 350 MW.

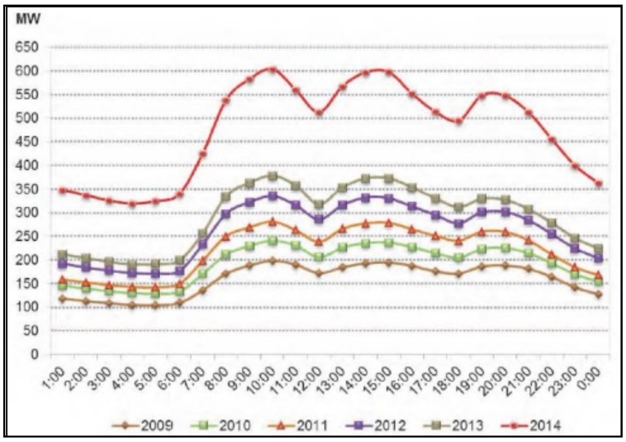


Figure 10-34. EDC Daily Load curve. Source: *EDC Annual Report, 2014.*

The ability of a hydro project to serve as the battery to shift loads from one hour of the day to another, with the objective of increasing the project's overall value to the system by providing more power during the peak hours, depends on the available storage. Ideally, one would decrease the output of hydro turbines as the solar PV ramps up in the morning, allowing the reservoir to fill during the hours of peak PV output. Then, as the PV system output declines, the hydro output increases: but there is now more water in the reservoir than would otherwise have been the case, so the total generation during the peak hours will increase. In Appendix 10.1 we describe in more detail how the world's largest integrated PV-Hydro project functions in exactly this manner.

This benefit of integration will generally be possible throughout the dry season, but there arises a problem in the wet season when the reservoir is in spill condition, and the hydro project runs 24 hours a day. Under these conditions, the PV power has to be evacuated in the hours when it produces, and is therefore limited by the ability of the transmission system to evacuate more power than the maximum output of the hydro station – which in the case of LSS2 means 400 MW. If the line were limited to 400 MW evacuation capacity, then there would be no choice but to curtail the output of the PV system.

The transmission studies presented above suggest this is *not* the case for LSS2: the transmission line from Stung Treng to Phnom Peng indeed has the capacity to evacuate up to around 800 MW, needing only some additional reactive compensation. But even if the additional power *could* be evacuated to the PP load center without loss of stability, the dispatcher would have to ramp down some thermal generators to match total generation to the total load. Fortunately, given the load shape of the EdC system, the 2-3pm peak could easily be supplied by this additional solar PV energy.

LSS2 Power Generation in the Absence of the Solar PV Add-on.

Unfortunately, we have not been provided with the feasibility study of the LSS2 project, without which it is difficult to simulate the operations of the hydro project. Therefore, our estimates of generation must necessarily rely on a simple model of energy production, driven by the hydrology data that is available (a time series of streamflow measurements from 1960-2002, plus data from 2003-2008 derived indirectly using rating curves), and some basic equations relating daily generation to inflows, net head, and turbine-generator efficiency.

Figure 10-35 shows our estimate of annual generation at LSS2 for the 49 years of historical record available. The average is 1,807 GWh/year. This is significantly less than the 1,912 GWh/year that is the publicly announced expected average generation at LSS2.

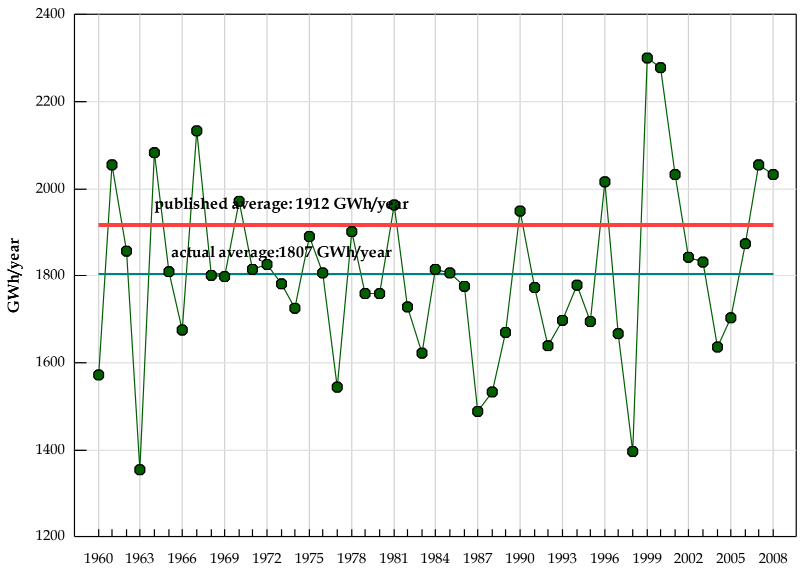


Figure 10-35. Estimates of annual hydro generation at LSS2.

Using a different methodology based on stochastic hydrology, we derive an expected average annual generation of 1,812 GWh/year (see Text Box 10-2). In the absence of the FS it is difficult to explain why our estimates are significantly lower, but clearly any detailed feasibility study of the solar PV project would need to have access to this detailed information, if at all possible with updated hydrological information since 2008.

Notable is the large variation from year to year: the most extreme case being in 1998, with generation of just 1,400GWh, followed a year later with generation of 2,300 GWh. This far exceeds the likely variation in the output of the PV system, which would unlikely vary by much more than 5-10% around the mean. A 200 MW PV add-on, at a capacity factor of 17.8%, would produce a more or less constant 311 GWh per year. [28]

[28] Whether there is an inverse correlation between hydro inflows and solar insolation is likely to be highly site-specific. But it would be reasonable to expect that there is more cloud cover in wet years, and so wet years might have lower PV output, and dry hydro years higher PV output – an inverse correlation that would be beneficial in smoothing out the annual variability.

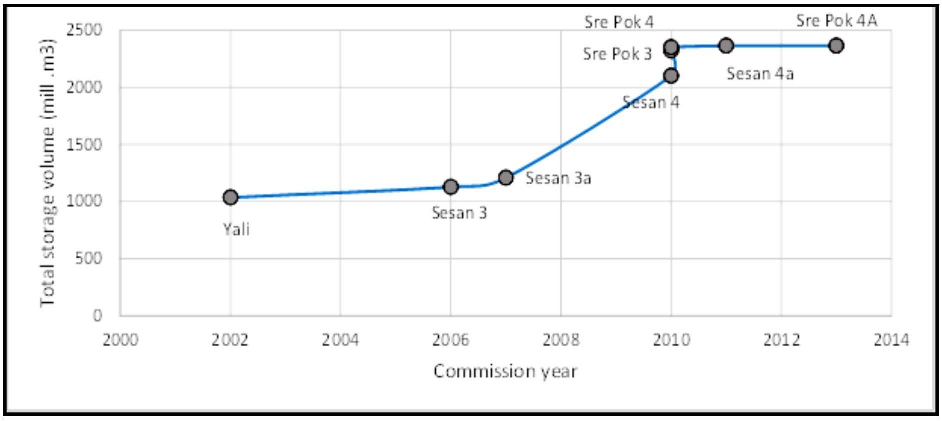


Figure 10-36. Commissioning of dams in Vietnam upstream of LSS2 that could modify the river's hydrologic signature.

One of the issues for generation at LSS2 is the extent to which the natural variability of inflows, as reflected in Figure 10-35, is affected by the regulation effects of projects upstream. The first major increment of upstream storage would have occurred in 2002, when the Yali hydro project in Vietnam came online. Figure 10-36 shows the increase in upstream storage over time due to upstream projects. One would expect that with high levels of upstream storage, dry season inflows would increase.

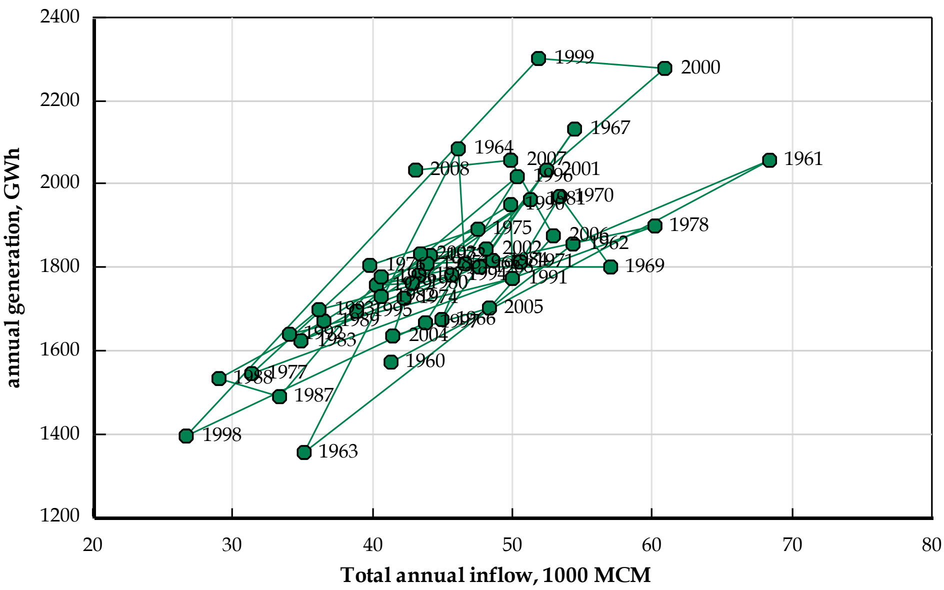


Figure 10-37. Relationship of annual generation with inflows.

Most of this variation is attributable to wet season variation, and the distribution of storms in the watershed: when storms are very intense, much of the additional water is spilled, and so does not contribute to additional generation: where rainfall is more even, the proportion of spill decreases, and generation increases. In the dry season (defined here as the five-months of January to May) that is quite different, as shown in Figure 10-38 by the almost perfect linearity between additional flow and additional generation – a reflection of the fact that during the dry season, there is no spill – every additional cubic meter of inflow can be productively used for power generation.

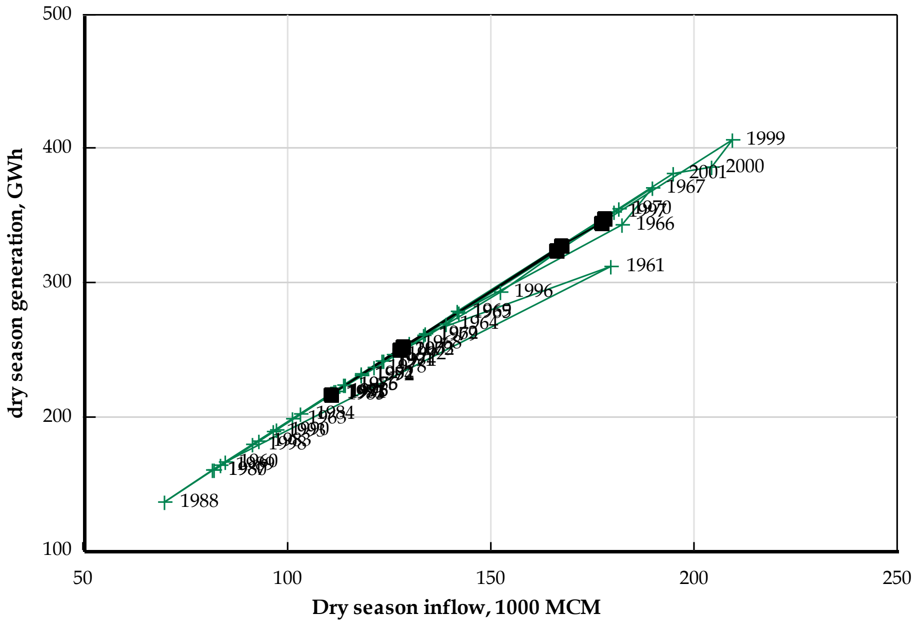


Figure 10-38. Dry season generation at LSS2.

Impact of the Floating PV System

As a facility that has not yet started generation, one can obviously not superimpose the additional PV energy on an existing pattern of hydro generation, whose dispatch is determined by the instructions of the system operator. However, the active storage volume of 333 million cubic meters[29] (MCM) is fairly large compared to the rated turbine discharge of 2,119 cumecs, which means the facility permits daily peaking operation during such times as the reservoir is not in spill condition. It is reasonable to suppose that EdC would wish to operate the project during peak hours, except during the wet season when there may be extended periods when the project could operate 24 hours a day.

A 200 MW solar PV project will produce roughly 0.854 GWh of energy per day during the hours of sunlight. This means that during these hours, the reservoir needs to store rather than discharge the water necessary to produce the same energy from hydro, which in the case of LSS2 works out at around 14.3 MCM each day. This means that at the beginning of sunlight hours, the reservoir would need to have been drawn down by this amount to make the necessary space.

From the hydro operator's point of view, the question is by how much the head is reduced for the remaining hydro generation during these hours. Although we do not have the detailed storage elevation curve, we do know that the active storage of 333 MCM draws down the reservoir by one meter. Assuming a roughly linear relationship, then to make space for the PV output, the water level would need to be reduced by 14.3/333=0.043 meters, so the head for any generation at the start of PV production would be 25.750-0.043=25.707. This represents a reduction of head (and hence of any hydro generation) of 0.167%. This loss is negligible compared to the extra energy provided by the PV system (and true even at 400 MW of PV).

[29] The Environmental Assessment for LSS2 records the active storage as 279 MCM.

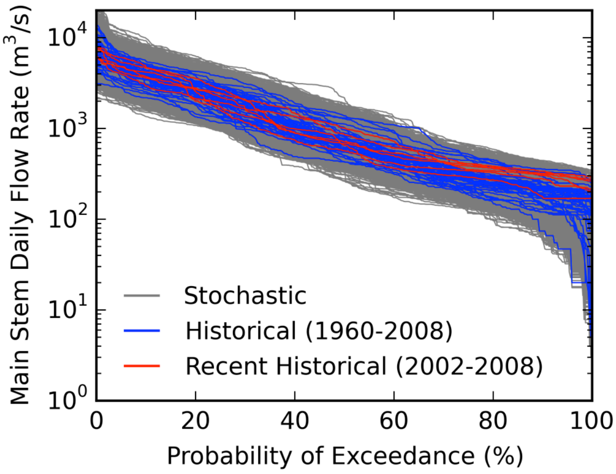
Text Box 10-2. Stochastic hydrology simulations

The Ban Kamphun (BK) gauge station was used to characterize LSS2 reservoir inflows, as it sits at the outlet of the Se San and Sre Pok Rivers. The gauge record is 49 years, though Erland added the 6 years from 2002-2008 using a rating curve. While the available 49-year-long hydrologic record (1960-2008) at BK is extensive compared to many regions of the world and contains significant variability, it nevertheless represents a limited sample of the Se San's and the Sre Pok's hydrologic extremes. By definition, extreme floods and droughts are rarely observed events. Consequently, the historical streamflow record is systematically biased towards underestimating the actual variability of these events.

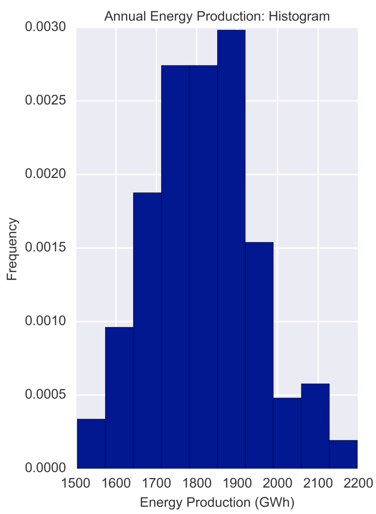
Drawing on the broad body of literature in synthetic probabilistic hydrology, we synthetically generated 100 different 100-year-long streamflow sequences (10,000 years) to model daily LSS2 inflows that better capture the system's variability while maintaining consistent historical statistics (i.e., mean, variance, and autocorrelation of flows). To generate each 100-year sequence, we first generated an auto-correlated sequence of monthly flows using the method of Kirsh *et al*. (2013), disaggregating monthly flows into daily flows using the bootstrapping approach described in Nowak *et al*. (2010).

To generate monthly reservoir inflows, we used only the historical statistics (autocorrelation, mean, and variance) from BK, generating synthetic flows that maintained these historical statistics. However, to be conservative, we only used the daily data from 1960-2001 to generate synthetic inflows. The figure shows the resulting annual flow duration curves for BK.

Each of the 49 blue lines represent a different year in the 49-year-long hydrologic record at BK. The most recent six years on record (2002-2008) are shown in red, demonstrating the appearance of a shift in the river's dry season hydrologic signature likely induced by operation of upstream dam(s). Each of the 10,000 gray lines in the background represents each year in 10,000 years of synthetically generated inflows. The synthetically generated sequences bound much of the recent variability, despite having been generated without the 2002-2008 data. However, it does appear to be the case that in the upper exceedance probability range (dry season), the recent years have fairly high dry season flows.



The histograms show the simulated total annual energy production (left) and total dry season energy production (right) resulting from simulating a run-of-river operating policy at LSS2 (full reservoir at 75 masl). This operating policy was stochastically evaluated by exposing it to five 100-year-long synthetically generated sequences of daily inflows (gray lines in the figure above. The area under each histogram sums to 1. Mean annual energy production is 1816 Gwh/yr, with a standard deviation of 132 Gwh/yr.



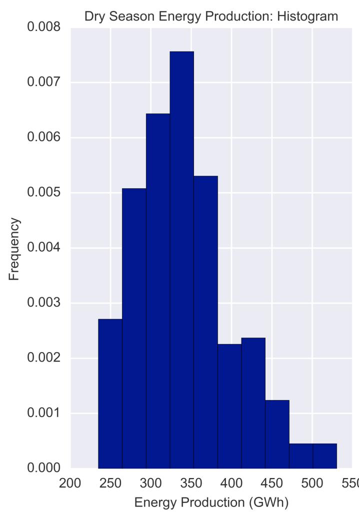


Figure 10-39 shows the impact of PV production on the dry season energy. In a typical year, the dry season generation is around 250 GWh – this increases to 400 GWh, and with 400 MW of PV increases to ~550 GWh. Moreover, in the dry season, the reservoir would never be in a spill condition, so all of this energy can be shifted to whatever hours of the day demanded by the system dispatcher. With many new hydro projects expected in Cambodia, all of which will have similarly low dry season generation, the ability to significantly increase peak season dry season generation is of substantial benefit to EdC.

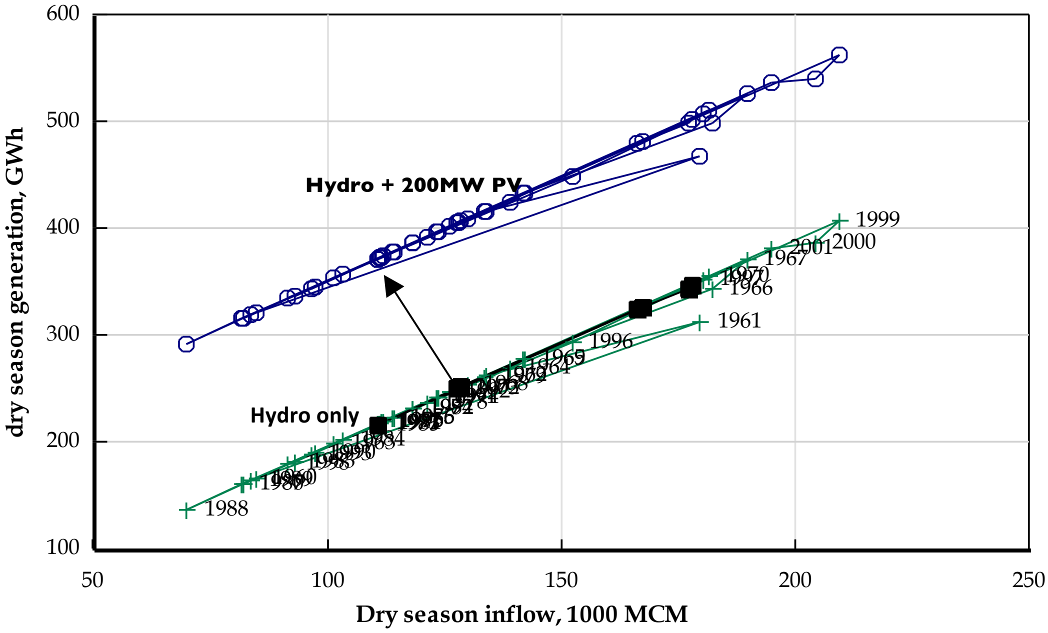


Figure 10-39. Impact of 200MW on dry season output at LSS2.

Because of the structure of the hydro PPA – a single price per kWh, not differentiated by time of day – there is little benefit to *the operator and owner* of LSS2 to generate dry season peak power. But where generation tariffs do reflect time of day and season (as for example as does the avoided cost tariff for renewable energy producers in Vietnam), hydro operators would have a direct financial benefit of such PV.

In the wet season, the ability to shift PV to peak hours is limited, because the reservoir may be in spill condition for prolonged periods, which means the hydro is in operation 24 hours a day, so PV energy must be evacuated at whatever time is it produced. Figure 10-39 shows the length of time the LSS2 reservoir may be in such a spill condition, in wet years as much as the equivalent of four months a year, and in very dry years less than two months of the year: the average is 3 months per year.

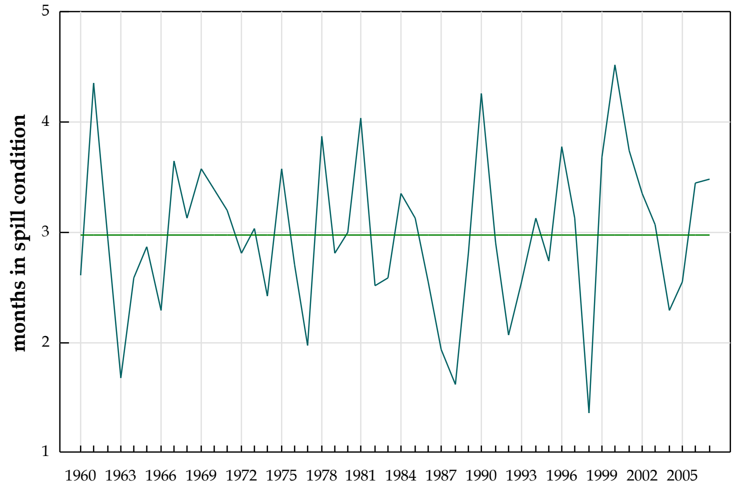


Figure 10-40. Months during which LSS2 may be in spill condition.

However, this will unlikely occur as a continuous condition. Figure 10-41 shows the number of hours a day that the reservoir can generate at full power (i.e. at the full discharge rate of 2,119 cumecs). When this is 24 hours a day, it signals that the reservoir is full. One observes that in June to August there occur significant inflow fluctuations, and continuous periods of reservoir full condition only from August onwards.

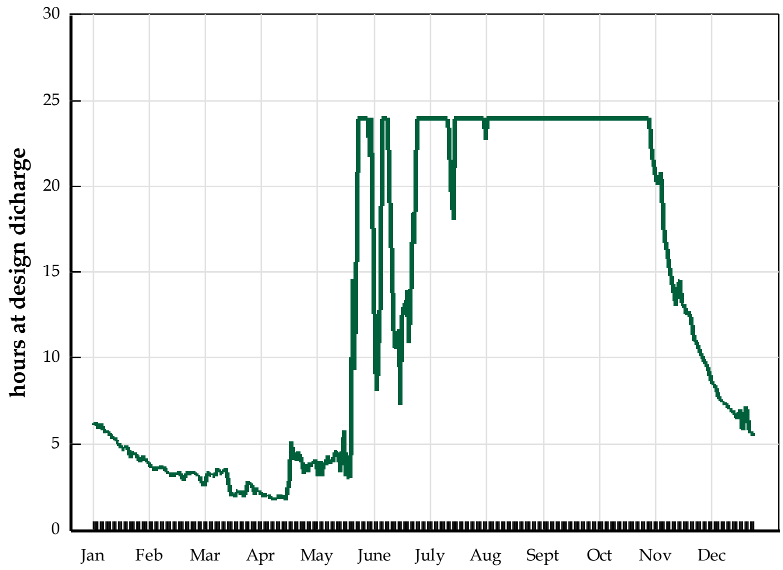


Figure 10-41. Number of hours per day at maximum discharge (1961).

The Economics of Floating Solar PV

PV Module Prices

PV module prices have decreased sharply over the past decade (Figure 10-42), though the market has recently exhibited some volatility: the sharp decrease of some 38% in 2016, attributed largely to overcapacity concerns, has significantly decelerated in 2017, and recent market movements have also been influenced lingering import tariff disputes in the US.

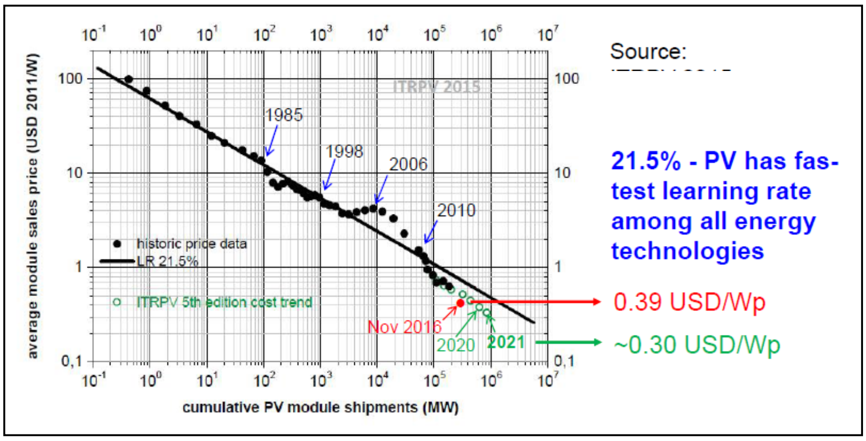


Figure 10-42. Learning curve and price forecast for PV modules. Source: ITRPV (2015)

However, further cost cutting efforts by the manufacturing industry should continue to put downward pressure on prices, and PV panel prices will continue to account for a decreasing share of the total system cost. Figure 10-43 shows the expected future module price development, using the expected progression of cost elements of PV systems in Asia as a basis.

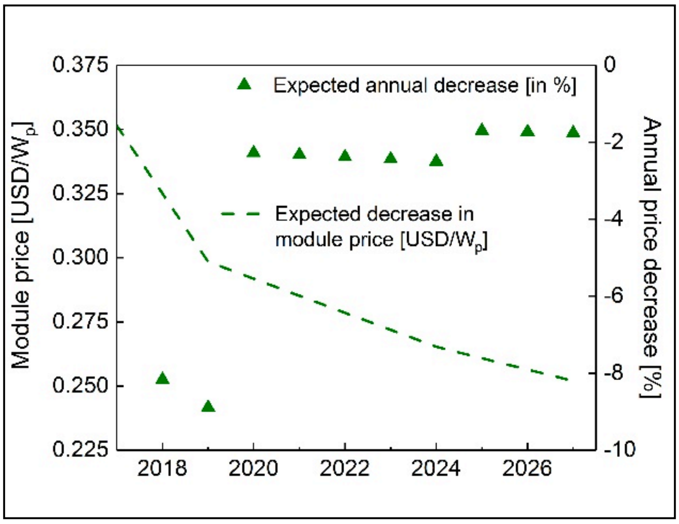


Figure 10-43. Expected future module price development. Source: ITRPV (2017).

Floating PV Systems

In most press releases announcing new floating PV projects, the investment cost is typically not released. However, from what is available in the public domain is presented in Figure 10-44, sorted by the month of commissioning (and converted to $US at November 2017 exchange rates).

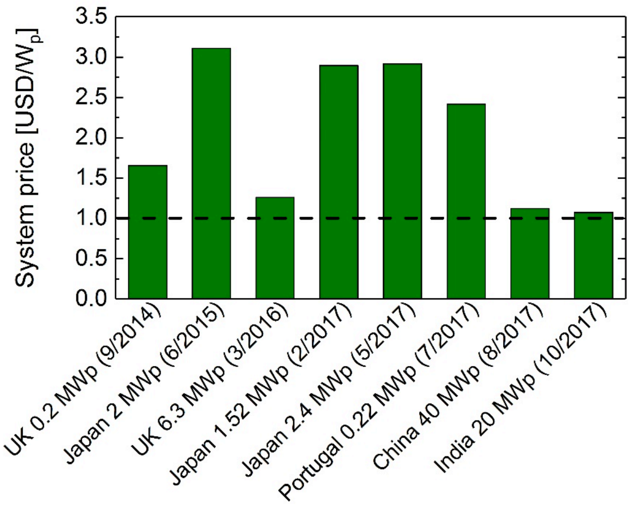


Figure 10-44 : Investment costs for floating PV systems.

The systems for which data is available are as follows:

1) 200 kW_p project in Berkshire, England, completed in 2014. This was the Britain's first floating PV system with an investment of ~£250,000 (The Telegraph, 2014).

2) 2 MW_p project in Shiroishi, Japan, completed in 2015 on an impounding reservoir. The total investment cost was reported as ~700 million yen (Sourcing71, 2015).

3) 6.3 MW_p project from Thames Water in London, England, completed in 2016 on the Queen Elizabeth II reservoir. After a 5-year planning and construction phase, the total investment cost was cited at approximately £6 million (Energy Trend, 2016),

4) 1.52 MW_p project in Kagawa, Japan, completed in 2017. The Mita Kannabe Pond Solar Power Plants, as it is named, was done at a total investment cost about USD $4.4 million (Renewables Now, 2017).

5) 2.4 MW_p Noma Pond Solar Power Plant in Kagawa, Japan, completed in 2017. Implemented under a FIT regime. The total project cost was reported as US$7 million (Renewables Now, 2017a).

6) 220 kW_p project in Montalegre, Portugal, completed in 2017, in combination with a hydro-electric power station, reported at €450,000 (PVTech, 2017).

7) 40 MW_p project in Anhui, China, was built at the site of a former coal mine and completed in 2017. Total investment was reported as $US 45 million (Quartz Media, 2017).

8) 2 x 10 MW_p projects in Andhra Pradesh and Kerala, India, completed in 2017. The projects are funded by the World Bank, with an investment of around Rs 70 crore each (Economic Times, 2017).

Figure 10-45 shows the composition of costs for a typical floating PV system. This system cost is not too different from a ground mounted project, because while the cost of floats is included, no land purchase is required, and civil works ground preparation cost is much lower.

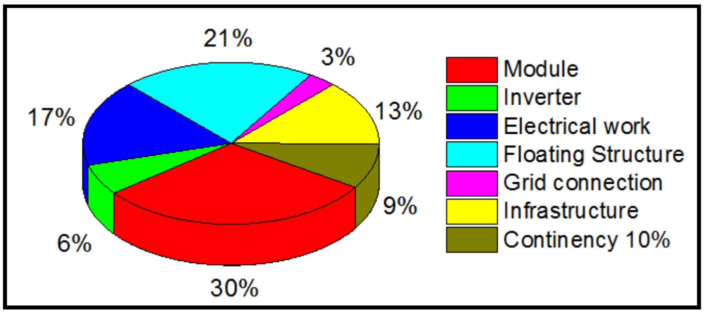


Figure 10-45: PV system breakdown (at 50MWp plant scale). Source: SERIS estimates.

Inverter Prices

Inverter prices are negotiated at more regional levels; hence no exchange price data is available for a "global" benchmark price. However, inverter prices have similarly come under pressure as panel prices lately and it is expected that a continued gradual reduction, levelling off in the medium term, should be possible. It is assumed that the prices will continue to decline, albeit at a lower rate than modules, from a level of ~US$0.065 /$W_p$ to ~US$0.050/$W_p$ over the next ten years.

Floating Structure, Electrical Work and Others

The other cost component assumptions in Figure 10-37 are based on internal SERIS experience, investigations and guidance from suppliers and EPC companies. It is noteworthy that these figures represent only estimations and need to be adjusted once the design and location is clearer. Especially the cable length could alter the electrical cost component. In addition, the grid connection cost does not include any grid upgrade works or addition substations. Under infrastructure various works are included, such as the overhead transmission cable cost from floating to an existing substation, as well as civil works and site preparation upgrades (e.g. inverter housing, launch ramp and land/civil works for the construction, land needed for floating structure production and assembly). Various sources are available regarding additional cost of tracking systems, especially 1-axis versus a fixed-tilt system. Some assessments only see a difference of 8% in total investment (NREL,2017), while local EPCs believe the premium is as high as ~24% compared to fixed-tilt system. SERIS assumes a CAPEX increase of ~16%, by adding an additional $0.01/$W_p$ for the inverter and US$0.20/$W_p$ at the structure side for the 1-axis tilted system.

Regarding the floating structure, it is assumed for this kind of volume, that the floats will be constructed on-site, hence no transportation cost is included. Anchoring cost is included in the price stated above, but might change when exact environmental conditions and design is known. The future cost of the floats can also be impacted by changes of in the price for high-density polyethylene (HDPE). In addition to the usual market forces of supply and demand, HDPE prices are also influenced by international oil price progressions. Excluding this factor, some of the key player's target is to decrease the cost by ~US$0.01-0.02/$W_p$ annually. We assume a reduction of US$0.015/$W_p$ per annum, levelling off thereafter.

OPEX

Table 10-15 summarizes the annual operating expense assumptions. The operating and maintenance part assumes a 30% premium for the 1-axis tracker system and a slightly higher premium for floating PV systems. As capacities for floating PV systems are only now starting to pick-up, it is prudent to assume that maintaining these systems is higher due to inexperience. The difference to ground-mounted systems however should slowly reduce over time with more systems getting deployed and increased knowledge and efficiency to maintaining systems on water. One issue to consider is cleaning cost, as significant soiling has occasionally been experienced in the case of the Singaporean floating test-bed, particularly from birds. The basis per kW_p used below of ~15-16 USD/kW_p for the floating PV system looks to be a conservative estimate when compared to the latest Lazard study which uses a range of 9-12 USD/kW_p for utility-scale PV projects.[30]. The first year's insurance expense is based on the assumption of 0.3 % of the total initial investment for ground-mounted, and 0.4% for the 1-axis tilted and floating PV systems, respectively.

Table 10-15: OPEX assumptions.

Operating expense break-down*	Ground-mounted PV (USD) fixed tilt	Ground-mounted PV (USD) 1-axis tracker	Floating PV (USD) fixed tilt	Ground-mounted PV (USD/kWp) fixed tilt	Ground-mounted PV (USD/kWp) 1-axis tracker	Floating PV (USD/kWp) fixed tilt
Operating & maintenance	250,000	325,000	350,000	5.0	6.5	7.0
Insurance expense	146,700	227,600	202,600	2.9	4.6	4.1
Inverter warranty extension	220,637	223,507	220,637	4.4	4.5	4.4
Total	617,337	776,107	773,237	12.3	15.5	15.5
Difference to ground-mounted fixe-tilt:		*26%*	*25%*		*26%*	*25%*

**1st year for the O&M and insurance expense, nominal value for inverter warranty extension expense*

Inverters' operational life is difficult to predict. While in the field, the so-called "mean time between failures" (MBTF) of 1-16 years can be observed:[31] inverter manufacturers typically provide 5-12 year warranties. For this project, a five-year warranty was assumed. Therefore, for an investment horizon of 20 years, replacement of inverters needs to be taken into account at least once during the operational life of the project. Apart from accounting for the replacement investment of inverters at the time of failure, there is usually an optional choice provided by the inverter supplier to buy a warranty extension in year five for a subsequent five years' period at ~20% of the prevailing inverter cost. A detailed cost benefit analysis needs to be done to find the proper trade-off between expected operating lifetime of the inverters versus the cost of warranty extension.

For this analysis, it is assumed that the warranty will be extended based on five years' intervals. The warranty extension cost is assumed to increase with the age of the inverter portfolio. An inverter manufacturer might be less willing to extend a 10-years old inverter portfolio (in which some of the inverters were replaced in the prior five-year period, but most-likely not all of them), than a five-years' old inverter portfolio. For the base case, it is assumed that the warranty extension cost will be 20% of the prevailing inverter price in year five, 45% in year 10, and 60% in year 15. The values above in Table 10-15 represent the nominal amount in case the whole inverter warranty expense over the projects' 20 operational years will be done on an annual basis (not discounted). A replacement of the tracker system has not been taken into consideration.

[30] Lazard, "Lazard's levelised cost of energy analysis - version 11.0," https://www.lazard.com/perspective/levelized-cost-of-energy-2017/

[31] J. Flicker R. Kaplar M. Marinella and J. Granata, "PV inverter performance and reliability: What is the role of the bus capacitor? " Photovoltaics Specialists Conference (PVSC), vol. Volume 2, no. 2012 IEEE 38th, pp. pp. 1-3, 2012.

Total Cost Assessment

Table 10-16 and Figure 10-46 shows our forecast for the capital costs of floating PV systems over the next decade.

Table 10-16. Assumed investment cost development of a 50 MWp PV floating system over time.

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Module	0.352	0.325	0.298	0.292	0.285	0.279	0.272	0.265	0.261	0.256	0.252
Inverter	0.065	0.064	0.062	0.061	0.059	0.058	0.056	0.055	0.053	0.052	0.050
Electrical Work	0.206	0.206	0.206	0.206	0.206	0.206	0.206	0.206	0.206	0.206	0.206
Floating Structure	0.220	0.205	0.190	0.175	0.160	0.145	0.145	0.145	0.145	0.145	0.145
Grid Connection	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030
Infrastructure	0.150	0.150	0.150	0.150	0.150	0.150	0.150	0.150	0.150	0.150	0.150
Total	**1.022**	**0.979**	**0.936**	**0.913**	**0.890**	**0.867**	**0.859**	**0.851**	**0.845**	**0.839**	**0.833**
Contingency 10%	0.102	0.098	0.094	0.091	0.089	0.087	0.086	0.085	0.084	0.084	0.083
Total (incl. cont.)	**1.125**	**1.077**	**1.030**	**1.004**	**0.979**	**0.954**	**0.945**	**0.936**	**0.929**	**0.923**	**0.916**
System cost reduction:		*-4.2%*	*-4.4%*	*-2.5%*	*-2.5%*	*-2.6%*	*-0.9%*	*-0.9%*	*-0.7%*	*-0.7%*	*-0.7%*

Source: SERIS staff forecasts

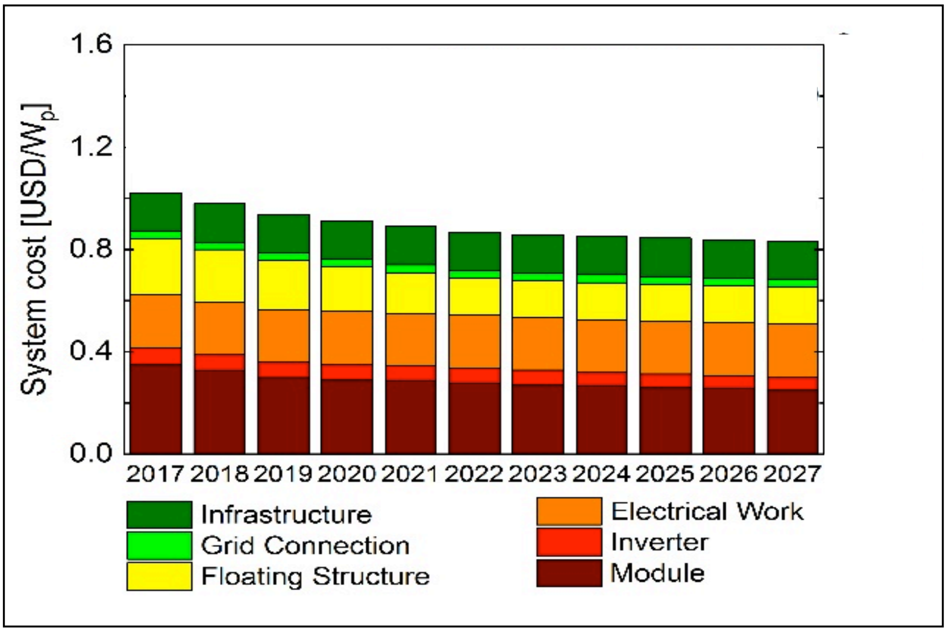


Figure 10-46. CAPEX progression over time (based on declining system cost assumptions of Table 10-16).

Screening Analysis

Levelised cost of energy (LCoE) is widely used to compare projects. It is also widely *mis*used, for the simple reason that comparison of *costs* only conveys useful information if the different options provide the same level of *benefits.* LCOE is defined as follows

$$LCOE = \frac{\sum_i \frac{I_i + O_i + V_i}{(1+r)^i}}{\sum_i \frac{E_i}{(1+r)^i}}$$

where

I_i = Capital expenditure in year i
E_i = Net energy production in year i
r = Discount rate
i = year, running from 1 to N where N is the economic life
V_i = Variable operating costs (including fuel, if any) in year i
O_i = Fixed operating costs in year I (including any major maintenance and life extension outlays

Normally, LCOE is presented as the *economic* LCoE at constant prices, which definition is used in this section. The *financial* analysis, together with a more formal economic assessment that includes the cost of mitigating measures, is presented in Section 11. Table 10-17 presents the LCoE for the six technical options discussed above, this excludes any import duties or taxes, and all values are at constant 2017 prices. The fixed axis systems have the lowest cost for both ground mounted and floating systems. This confirms the rationale for proposing fixed-tilt floating systems for LSS2.

Table 10-17: Levelised economic cost of floating PV (10% discount rate).

		Ground mounted			Floating		
		fixed tilt	1-axis tracker	2-axis	fixed tilt	1-axis tracker	2-axis
Performance							
installed DC (	kWp	50000	50000	50000	50000	50000	50000
AC to DC out	[ ]	0.836	1.014	1.014	0.891	1.014	1.014
AC output	kWac	41799	50710	50710	44555	50710	50710
Produced ene	MWh/year	93925	97700	98250	93140	99950	104350
capacity facto	[ ]	17.9%	18.6%	18.8%	17.8%	19.1%	19.9%
Capital costs							
unit investme	$/Wp	978	1138	1213	1013	1173	1256
	$USm	48.90	56.90	60.65	50.65	58.65	62.80
annualised c	$USm/year	4.98	5.80	6.18	5.16	5.97	6.40
OPEX							
unit cost	$/kWp	12.30	15.50	17.3	15.50	19.4	20.2
annual OPEX	$USm	0.62	0.78	0.87	0.78	0.97	1.01
total cost	$USm	5.60	6.57	7.04	5.93	6.94	7.41
cost per kWh	USc/kWh	5.96	6.73	7.17	6.37	6.95	7.10

Note that these costs are at constant prices (i.e. excluding inflation), and do not include integration costs (batteries, additional transmission costs, additional reactive compensation) – whose impact is discussed in Section 11. These results are dependent on the discount rate, as shown in Table 10-18.

Table 10-18: Sensitivity of LCoE to the discount rate.

	Ground mounted			Floating		
	fixed tilt	1-axis tracker	2-axis	fixed tilt	1-axis tracker	2-axis
Discount rate						
6.00%	**5.19**	**5.87**	6.26	**5.57**	6.09	6.21
8.00%	**5.96**	6.73	7.17	**6.37**	6.95	7.10
10.00%	**6.77**	7.63	8.13	**7.22**	7.86	8.04

The Economics of Battery Storage

Two potential applications of storage batteries are of interest to solar PV

- As a tool to absorb output fluctuations of solar PV
- As a tool to shift PV generated during peak sunlight hours to evening hours when the grid has highest need for power.[32]

The technical characteristics of batteries will be quite different in these two applications: in the first case, fast acting storage devices such as batteries or flywheels will be randomly operating in either charge or discharge almost continuously, whereas for energy shifting there might well be just one

[32] In the jargon of storage battery economics, this is described as “arbitrage”.

charge and one discharge cycle each day, with quite large amounts of energy being stored. In the latter case this could be achieved indirectly by raising and lower hydro generation production.

Figure 10-47 illustrates the principle by which fast acting storage to fulfill first function – to absorb short term fluctuations for frequency control. This is for a 1.2 MW solar PV project in Hawaii (on the Island of Lanai). The project provides about 10% of the Island's energy, with 10.4 MW of diesel generators providing the 5MW peak load. Typical (*un*smoothed) output ramp rates of the PV project (the red line in Figure 10-47) were above 400 kW/minute, with a maximum observed rate of 760 kW/min. The project's battery storage system was designed to limit the ramp rate to 360 kW/minute. In the example of Figure 1, during the first 15 minutes one observes that the *smoothed* output increased from 300kW to 1,000kW, equivalent to 47 kW/minute. The amounts of energy stored/discharged are very small - on the order of a few kWh (with a range of power absorbed at ± 75 kW).

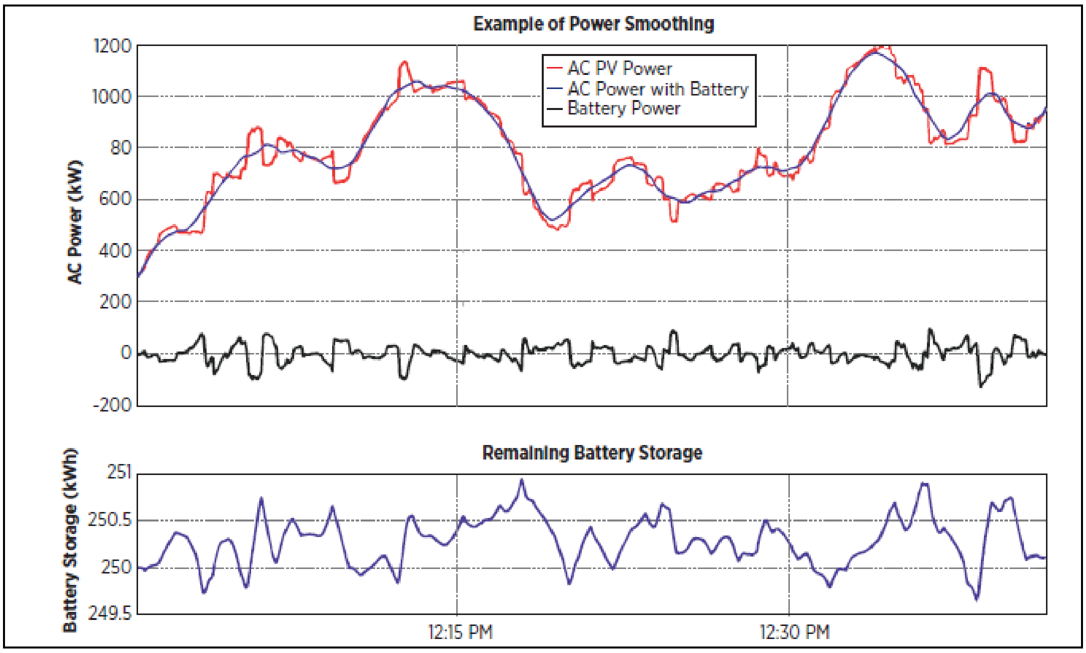


Figure 10-47. Battery for power smoothing. Source: J. Johnson et al Initial Operating Experience of the La Ola 1.2 MW Photovoltaic system, Sandia National Laboratory. Report SAND2010-8848, October 2011.

A floating PV system integrated with a hydro project has little need for the second application, because this can be accomplished simply by using the storage capacity of the reservoir. At such an integrated project, during sunlight hours PV is fed into the grid, with hydro output reduced (and its water equivalent retained in the reservoir); during peak hours (typically in the evening) the output of the hydro project will be increased (from the water stored during hours of PV output). [33]

The effectiveness with which this can be done depends on whether there is

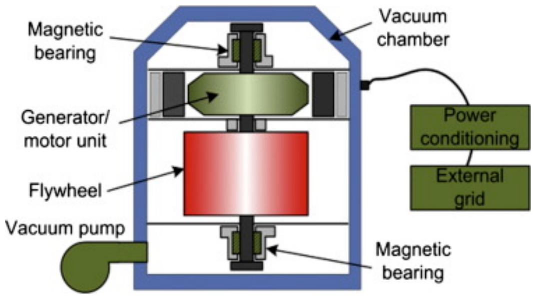
- sufficient available reservoir storage to act as a battery (a function of the so-called *active* storage)

[33] The reservoir operation model is discussed in more detail below.

- in the wet season when the hydro project may already be running at full output with the reservoir in spill condition, whether the transmission line has the ability to deliver additional power, and if not, then the output of the PV system must be curtailed.

These issues, and the extent to which PV output would need to be curtailed, are further discussed below.

It may well be that for the specific purpose of absorbing short-term fluctuations (as opposed arbitrage or time shifting output), flywheel technology may be the preferred technology by the mid to late 2020s.[34] This technology has several key advantages, notably that they have unlimited cycling over a 30-year lifetime, and involve no potentially hazardous materials. A first commercial scale project is underway at a 17 MW wind farm in Alaska.[35]



Cost of Battery Storage

The most common measurement of utility scale battery storage systems as $/kWh Stored. However, this costing approach applies to batteries designed to store energy in significant amounts appropriate to the service required. Thus, the variable cost of increments storage is lower than the fixed cost of insulation, control and inverter equipment. For batteries or flywheels with a small but fast acting repetitive energy storage/generation component the fixed costs based on $/kW dominate in battery pricing.

The prospects for significant reductions in battery storage costs are extremely good, particularly in light of the huge investments currently underway for improved batteries for electric cars. Battery prices have fallen by 50% since 2010. The global market for utility scale battery storage systems is expected to grow from the currently installed 540MW in 2014 to 21,000 MW by 2024, with a learning curve comparable to that experienced for PV.[36] In the US, battery storage was being driven by a California Law that requires the State's investor-owned utilities to purchase 1.3 GW of storage capacity by 2013. The median price reported for use with utility scale projects in the US in 2015 was US$900/kWh. *Tesla automobile*'s claims that it will achieve US$250/kWh may take some time, but clearly automobile use will be the main driver for technology innovation in batteries. Figure 10-48 shows recent trends and forecasts.

Conceptually, the economics of battery systems for peak shifting are no different from that of a pumped storage project – the *economic* case depends entirely on the difference in benefit between off-peak power and peaking power. And just as in the case of pumped storage, where the conversion

---

34 Flywheel is a mechanical storage device which emulates the storage of electrical energy by converting it to rotational kinetic energy. The flywheel speeds up as it stores energy and slows down when it is discharging. The rotation flywheel is driven by an electrical motor-generator (MG) performing the interchange of electrical energy to mechanical energy and vice versa. Flywheel is composed of five primary components: a flywheel, a group of bearings, a reversible electrical motor/generator, a power electronic unit and a vacuum chamber.

35 http://www.energystoragenetworks.com/might-flywheels-impact-transmission-grid-renewables/

36 *Energy Storage Market Outlook 2015*, Renewable Energy World, February 11, 2015.

from off-peak to peaking power is subject to the penalties of pump-up efficiency (~0.7), and generation efficiency (~say 0.9), so perhaps 65% overall. In the jargon of battery storage one speaks of "round trip efficiency" – which is generally much better at around 85-90%.

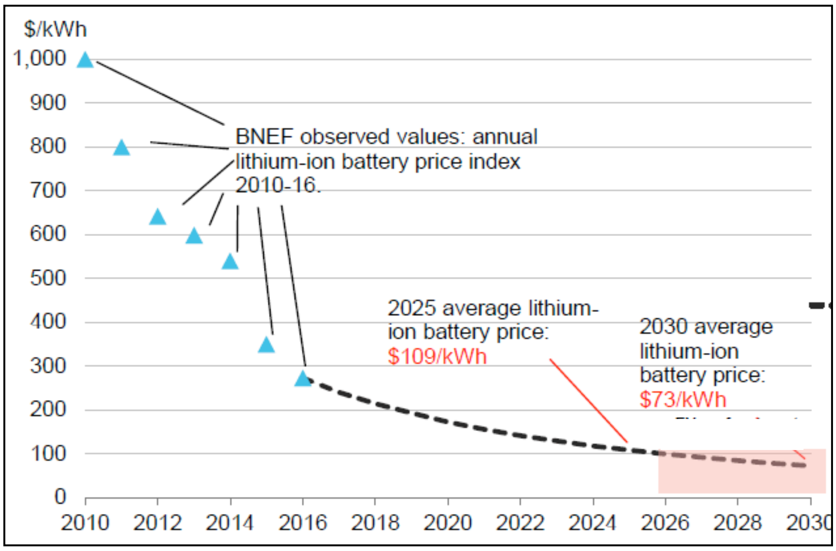


Figure 10-48. Expected Battery storage costs. Source: Bloomberg New Energy Finance. Note: Historical prices are nominal; future prices are at constant 2016 US$

A major problem with chemical (e.g., Lithium) batteries is that their lifetime is strongly related to the number of charge/discharge cycles. Typical lifetimes seen in the literature suggest batteries have lifetimes of 10-15 years under normal operating conditions, so considerably shorter than PV panels, though perhaps longer than inverters. Intervals for battery replacement is therefore one of the variable in the economic analysis (Section 11).

These problems are avoided by flywheels, whose life is not affected by charge/discharge cycles. The prospects for cost decreases for flywheels are just as likely as for batteries (de la Parra *et al*., 2015)

How Much Battery Storage Might be Needed at LSS2

At an integrated hydro-solar PV system, the extent of battery storage would be determined by the max ramp rate that can be accommodated by the hydro turbines, and the maximum frequency disturbance that can be accommodated by the EdC grid. At the time of writing, neither of these two variables is known: for the former we need more information on the turbine-generator characteristics actually installed at LSS2; for the latter we await the results of the PSSE modelling. However, an indicative order of magnitude estimate of the likely additional cost of battery storage can still be made, based on the La Ola project in Hawaii that is one of the few sources in the literature which provides reliable data on the impact of batteries on short term output fluctuations of a PV system. This is a very small system not comparable to the scale envisaged at LSS2, but it is one of the few examples with detailed monitoring data at the very fine scale of second required: it serves as an excellent explanation of the principles involved.

First, note Figure 10-49 shows the same profile as shown in Figure 10-47, but now controlling or a much longer time scale for ramp rate – so the cycles of battery charge and discharge are much longer than in Figure 10-49. Now the charge/discharge range for the battery is ± 200 kW. The ramp rate (i.e. the rate of change in the smoothed, blue curve) in the first 15 minutes is 600 kW/15 minutes, or 40 kW/minute (0.04 MW/minute). At Longyangxia, no battery augmentation is required where the ramp rate is 150MW/minute.

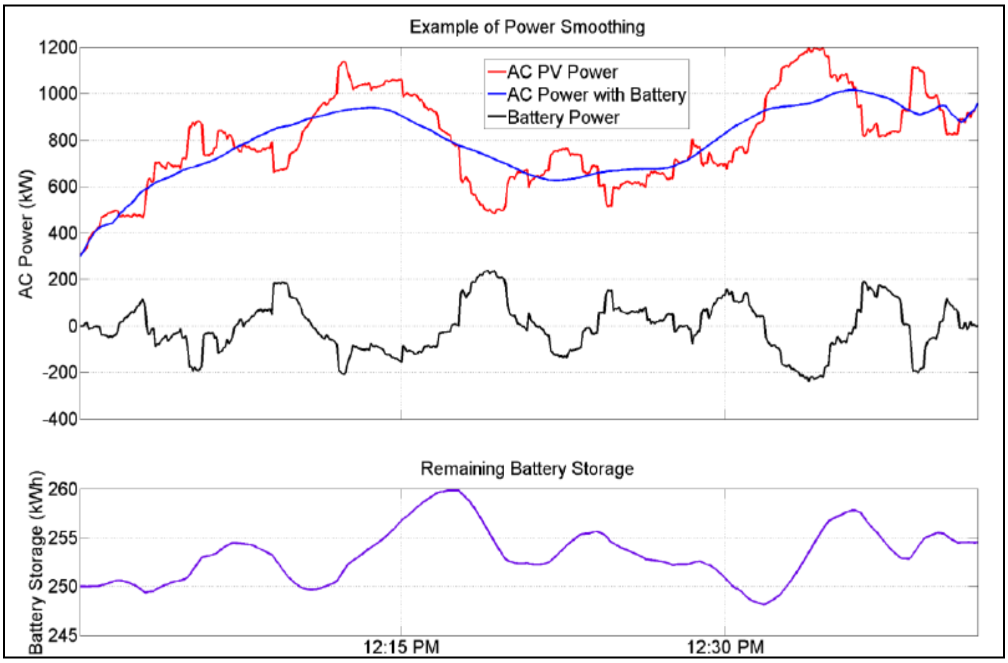


Figure 10-49. Power smoothing for longer time scale smoothing.

Table 10-19 presents the assessment of battery system costs. Column [1] presents the data for the La Ola system, before installation of the storage battery. The system output was limited to 600 kW, therefore representing just 12% of the system peak load. The maximum observed ramp rate for this system was 380kW/minute, but the frequency variations had little impact on the stability of the system. No significant change in the grid frequency was found due to PV output variability. In fact, the system frequency spread during the day was determined to be about the same as during the night, roughly 60.0 ±0.1 Hz. Similarly, the impact on the voltage profile was found to be negligible.

Table 10-19. Cost assessment. Source: NHI staff assessment.

			La Ola	La Ola	scaled to LSS2	scaled to LSS2 at 2020 prices	scaled to LSS2 at 2025 prices
			[1]	[2]	[3]	[4]	[4]
	PV system						
1	Installed capacity	kW	600	1200	100000	100000	100000
2	capacity factor	[ ]	0.18	0.18	0.18	0.18	0.18
3	annual PV energy	[MWh]	946	1,892	157,680	157,680	157,680
4	average daily generation	[MWh]	3	5	432	432	432
5	Cost of PV	[$/kW]		2000	2000	1000	900
6		[$USm]		2.4	200	100	90
7	**Battery**						
8	Battery capacity	[MWh]		0.5	41.7	41.7	25.0
9	Battery storage/daily output	[ ]		10%	10%	10%	6%
10	Cost of storage	[$/kWh]		1200	1200	500	300
11		[$USm]		0.6	50.0	20.8	7.5
12	battery cost increase	[ ]		25.0%	25.0%	20.8%	8.3%
13	**System Loads**						
14	peak load	[MW]	5	5	2552	2552	2552
14	PV peak output	[MW]	0.6	1.2	100.0	100.0	100.0
15	as fraction of peak load	[MW]	12%	24%	4%	4%	4%

This of course says little about the potential impact of large PV at LSS2 – for which PSSE runs are required. However, it does suggest that frequency and voltage issues from solar PV variability may not be a great as is sometime suggested.

Column [2] of this table shows the data for the La Ola system with battery storage. The report does not provide a cost figure, but from other sources we may assume that 2011 costs for this type of battery would have been around US$1,200/kWh. With 500kWh of storage, this results in a cost of US$600,000, about 25% of the likely capital cost of the PV plant itself.

In Column [3] we scale this to 100 MW at LSS2, using the same costs as for La Ola. Note that its output represents only 4% of the 2020 peak load in the Cambodia grid. However, 2009-2011 costs will have decreased dramatically by 2020: in Column 4 we assume that battery costs would have declined to US$500/kWh and PV costs to US$950/kW. The incremental cost of batteries falls to 20%.

It would seem that the battery system added to La Ola is oversized at 500kWh – 10% of the total daily output seems rather high: even when smoothing into longer cycles as shown in Figure 10-39, the range of remaining battery storage varies only by some 15 kWh. This oversizing was doubtless driven the need to be very certain that the project would not disrupt the supply to the Island system. In column [5] we reduce the required storage from 41.4 to 25 kWh, lowering further the cost increase (over the PV module itself, now down to 900$/kW) to 8.3%.

Text Box 10-3. Other applications of battery storage at solar PV projects.

The table provides information on PV projects with battery storage.

Project location/name	Riverland plant [30] Adelaide, Australia	Hawaiian island of Kauai [31]	Tomakomai City, Hokkaido, Japan [32]
Project completion year	end of 2017	2017	estimated Aug. 2018
Solar PV power plant size	330 MW	17 MW	38.1MW (25 MW grid connected)
Energy storage system size	400 MWh/ 100MW	52 MWh/13 MW	10 MWh/20 MW
Energy storage technology	Li-ion battery from AES	Li-ion battery from Tesla	Li-ion battery from LG Chem
Energy storage main function		Store solar power during the day and dispatch during evening peak from 5-10pm (arbitrage)	Prevent rapid output fluctuations
Remarks	Currently the World's largest solar and battery storage plant		Hokkaido Electric Power Company (HEPCO) requires Solar PV plants larger than 2MW to install battery storage. The project benefits from a very high feed-in tariff of 36 USc/kWh!

However, reliable information on costs at these facilities is hard to obtain. Battery storage at Riverland and Kauai is clearly of a capacity that suggests arbitrage – with large storage capacity suitable to shift delivery to evening peaks. But at Yomakomai, where the announced purpose is simply to prevent rapid output fluctuations, the estimated incremental cost is 14 %, comparable to that calculated in the text table 10-19.

			Riverland Australia	Kauai Hawaii	Tomakomai Japan
1	**PS system**				
2	PV system size	MW	330	17	38
3	assumed cost	$/kW	1000	1100	1100
4	cost	$USm	330	18.7	41.8
5	**Battery system**				
6	Storage	kWh	400000	52000	10000
7	assumed cost	$/kWh	750	600	600
8	cost	$USm	300	31.2	6
9	Total project cost	$USm	630	49.9	47.8
10	incremental cost	[ ]	91%	167%	14%

Note

The assumptions for cost of storage at Riverland matches press report total cost for batteries of $240-300million. Estimated PV panel costs are consistent with other very large PV costs at this scale.

Conclusions on Battery Storage

The conclusions and lessons for the floating solar project at LSS2 are as follows:

- Battery systems at utility scale may already be considered a commercially demonstrated technology, adopted by both private power companies and public utilities. They are modular, and can easily be added as the floating power plant plants increases in size over time.

- However, even given the expected decreases in battery storage costs over the next decade, battery storage may still represent a significant cost that warrants consideration in the economic analysis. If indeed batteries are required to smooth out short term variation, a private operator will doubtless be conservative.

- Battery storage systems can be designed to operate only when ramp rates would otherwise exceed a certain rate, thereby considerably extending their lifetime. As shown at La Ola, it may well be that most ramps up and down are easily absorbed by the grid system.

- Reliable estimates of economically optimal battery sizing will only be possible once data on ramp rates of the LSS2 turbine-generators are known in detail, and detailed PSSE model simulations have been completed. In the economic analysis of the next section we therefore treat the extent of required battery storage, and the extent of future cost reductions, as variables in the risk assessment. This analysis will show that any requirement for battery storage does not change the main conclusion.

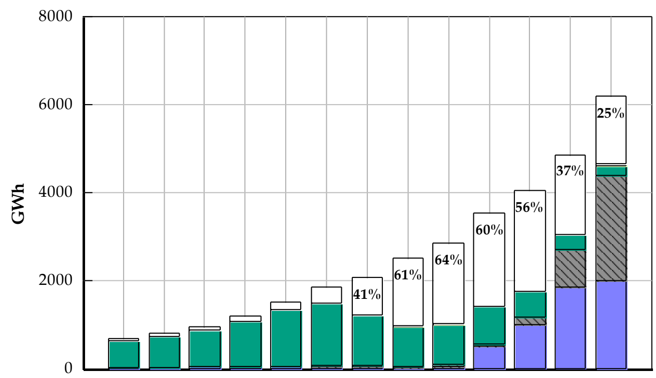
- It is possible that by the late 2020s, flywheels will be the technology of choice, primarily for reasons of unlimited cycling over a 300-year life, and the almost complete absence of hazardous materials. However, for the next few years, Lithium-iron batteries would be the indicated choice for application at LSS2 given their state of general commercial availability.

Electricity Trade

Current Situation

To what extent do the opportunities for electricity exports affect the Sambor project, and the proposed floating PV project at LSS2? The original CSP proposal for a 2,600MW scale project at Sambor envisaged export to the major load center of Ho Chi Minh City (HCMC), enabled by a 500kV dedicated transmission line. Given the existing synchronization of the Phnom Penh grid with that of Vietnam, this was considered technically and economically feasible without the need for an asynchronous back-to-back connection. At the time of preparation of the CSP feasibility study in 2009, Cambodia's estimated peak load was around 300 MW with sales of just 1850 GWh, and domestic demand, while already growing fast, was not judged able to absorb the 11,000 GWh of Sambor.

Moreover, in 2009, *imports* from Vietnam accounted for some 840 GWh, providing for 41% of supply. This import dependence was to grow further, reaching a peak of 64% in 2011 (Figure 10-50), but with the commissioning of recent hydro and coal projects, by 2015 this had declined to 25%. The commissioning of LSS2 is expected to eliminate significant imports altogether, opening up the possibility of Cambodia becoming a net exporter.



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
hydro	41	28	44	51	50	46	47	32	52	517	1015	1851	2000
coal						23	28	32	47	37	169	863	2376
diesel	595	715	835	1034	1294	1409	1152	899	909	857	579	327	228
wood&biomass			0	2	5	6	6	6	12	12	7	17	40
imports	58	59	82	108	167	374	842	1546	1829	2104	2281	1803	1541

Figure 10-50. Cambodia Historical generation mix.

At present, electricity trade in the region is of two types:

- *Opportunistic exports in small quantities to smaller neighbors*: 2,000 GWh of exports from Vietnam to Cambodia was very important to Cambodia, but represented a very small commitment for Vietnam. Such trade is obviously facilitated by synchronized systems: where synchronization is not present, the importing country isolates the region served by imports (as is the case of similar exports from Yunnan to the northwest corner of Vietnam). This trade is typically enabled by Government to Government agreements that fix prices and quantities.[37]

[37] This increase in exports was facilitated by an ADB assistance project to Cambodia project that built the 2 x 220kV transmission line from the Vietnamese border to PP (ADB Project 34390, *Greater Mekong Sub-region Transmission Project*)

- *Large dedicated, export projects*: typified by the 1,000 MW Nam Theun 2 project, dedicated to Thailand's EGAT over a dedicated transmission line synchronized to the Thai grid. The Laos grid does receive some part of the NT2 production, but this is achieved by a separate penstock, separate powerhouse and separate switchyard – unsatisfactory, but this was considered preferable to the alternative of an asynchronous back-to-back connection that would have enabled some part of the main output to be delivered to the Laos grid.

Large dedicated export projects require formal PPAs to enable development as private power projects. The importing off-taker must commit to a 20 year PPA deal, and the project developer is typically responsible for the necessary transmission line connections (or, as in the case for LSS2, constructed by another entity under contract to the off-taker). The 2,600 MW version of Sambor would have required precisely such an additional dedicated line.[38] A 500 MW scale hydro project would no less require such a PPA to enable its finance, even where off-take risks are covered by guarantees from Government or from International financial institutions.[39]

Ultimately, tighter integration of the grids among the countries in Southeast Asia is inevitable – either through synchronization of the major grids or through back-to-back asynchronous connections and HVDC interties. The latter is the most likely option in the short to medium term, that can be achieved in a first stage by bi-lateral agreements: synchronization of the two largest grids – Thailand and Vietnam – seems quite distant.[40]

Tight integration of national grids brings significant benefits to reliability, lower investment costs, and better integration of variable renewable energy – as well demonstrated in Europe: the high renewables share achieved in Northern Germany and Denmark would not have been possible without inter-connection to the large hydro resources in Norway and Sweden, and the thermal generation of the rest of Germany.

However, such successful regional integration of national grids, requires several preconditions

- creditworthiness of all of the participants, for in some months net trade may be in one direction, in the next month in the other direction: this requires both parties to be absolutely confident on prompt payment equalization.
- Agreement on the currency to be used
- Common provisions of the respective grid codes
- Agreement on the mechanisms for dispute resolution

Obviously, in Europe, the common currency and the legal framework of the EU has made such integration much easier than.

[38] Though the CSO FS is silent on the proposed contractual arrangements.

[39] Such a Guarantee, in the form of a so-called partial risk guarantee (PRG) was provided by the World Bank to the NT2 project in Laos.

[40] India serves as a good model. Initially, the four major grids were interconnected by back-to-back interconnections, with full synchronization achieved only much later, together with the establishment of the Indian Power Trading Corporation. True, few of the State Electricity Boards were creditworthy, but interconnection was facilitated by a common currency and a common legal framework and a National Electricity Regulatory body.

Vietnam as an Importer of Cambodian Power

At one point, Vietnam was to participate in the LSS2 project as an equity partner, with a view to obtaining a share of its output. Indeed, the Vietnamese 7th Power Development Plan prepared in 2010, envisaged some 1,200 MW of hydro imports from Cambodia.

> it is expected to have four hydropower plants in Northeast Cambodia to be developed sometime after 2015 to export electricity to Vietnam with a total capacity of 1,200 MW.[41]

However, EVN subsequently dropped out of the LSS2 project, and is no longer an equity partner, nor are there any expectations that a share of its output would be exported. The project is entirely guaranteed by the RGC, and its output can easily be absorbed by the fast-growing PP grid to the point of eliminating most *imports* from Vietnam. Moreover, in the 2015 Revisions of PDP7, it is stated that

> The government of Cambodia has recently changed its policy that does not allow hydropower exports. Therefore, electricity imports from Cambodia are not considered in this revised PDP7.

Whether this is an accurate representation of the actual position of RGC may be questioned, but as things presently stand, the Revised PDP7 has been officially approved by the GoVN, and would need to be reversed to enable imports in the future.

For reasons discussed below, we would expect vigorous opposition from Vietnam to *any* mainstream hydro project at Sambor. This would certainly apply to the 3 x 600 MW version of Sambor that is presently in the Cambodian Master Plan, and likely even to the smaller Alt_7A as well. It may be that ultimately Vietnam would be powerless to veto such a project, but it would certainly be in a position to block EVN signing a PPA to enable finance of such a project, and will certainly not provide RGC with a no objection certification that is necessary to obtain finance or PRGs from international financial institutions.

Nevertheless, it is also true that in late 2016, the Vietnam National Assembly voted to cancel the US$18 billion, 4,600 MW nuclear project that envisaged a first nuclear unit in 2028. In the absence of a dramatic downward revision of Vietnam's load growth forecast, this represents a significant gap in supply. However, nuclear would provide base load, and is not easily replaced by peaking hydro.

If indeed there are power shortages in Southern Vietnam in the mid to late 2020s, and if the systems remain synchronized, this would not preclude opportunistic exports of power to Vietnam, which would be in the interests of both parties. But that is quite different to Vietnam committing to a 20 year PPA to enable finance of Sambor. The construction period for a 1,500-2,600 MW scale project is at least 6-7 years, which means that financial closure for a first unit commissioning by 2028, for dedicated export, would need to be in 2020-2021.[42] Even with reversal of the current policy of PDP7 revised, that seems unlikely.

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[41] PDP7, Chapter 5.

[42] Indeed, to reach commissioning of the first 600 MW envisaged by the RGC expansion plan by 2025, would require financial closure by 2019.

Exports of Solar PV

There are two potential difficulties of exports of solar PV to Cambodia's neighbors. The first is that the solar resource in Cambodia is not very different to that of its immediate neighbors, which means that Cambodia's competitive advantage would be limited to possibly easier siting of large solar farms given lower population densities and lower pressures on land use.

The first such large scale such project proposed for Cambodia – a 225 MW development (with the first 15 MW installed at an industrial park in Kampong Speu province) has costs (according to Press reports) of about US$400 million, or some $1,780/kW. The first similar scale project announced in Vietnam – a 350 MW, US$421 million project in a 554-hectare project in Ninh Thuan Province by an EVN subsidiary[43], has proposed costs of $1,202/kW. While the reliability of such Press reports may be questioned, there is no evidence that Cambodian Solar PV projects would have significantly lower costs than those Vietnam.

Even solar PV projects for the domestic grid-connected Cambodian market require long-term PPAs – according to Press reports, the Sunseap 10MW project in Bavet with US$9.2 million in ADB financing has a 20-year PPA with EdC.[44]

The second potential difficulty for a dedicated export project is that any dedicated transmission as may be necessary to enable exports would have a very low load factor – given that the typical solar project has a capacity factor at best around 20%. This means that the cost per kWh exported will be high.

We conclude that where the transmission and synchronization arrangements are in place, small scale opportunistic exports may well be possible with incremental benefits to both parties. But the financing of *any* major export project will require a long-term PPA.

The ability of Cambodia to absorb significant amounts of solar PV is discussed in Appendix 10.2. With the Cambodian economy, and its electricity demand, continuing to grow rapidly, 100 MW of solar additions per year growing to 200 MW per year by the late 2020s would not exceed the 5% of peak load generally accepted as the threshold for absorbing variable renewable energy without difficulty. With the integration into an existing hydro storage project, integration issues at LSS2 will be even less of a problem than a stand-alone PV project of similar size.

400 MW of solar PV at LSS2, implemented in 100 MW increments, can therefore be proposed without any reliance on export sales. Even were there to be a capacity constraint on the transmission line to PP, an additional circuit could be added at much lower cost than a dedicated transmission line to Vietnam.

[43] A coastal province in Southern Vietnam some 300km northeast of HCMC.

[44] Bavet city is an area that presently imports some 20MW from Vietnam.

Conclusions

We draw the following conclusions

- Floating PV systems can be regarded as a proven technology. Unlike hydro projects, they have essentially no environmental damage costs and raise no problems related to relocation and resettlement of persons: concessional finance will not be impeded by the safeguards policies of the IFIs. The modularity and short construction periods make this technology well suited to the uncertainties of load growth in Cambodia – the timing of additional 50-100 MW increments can be easily be optimized to meet the demand growth – unlike large hydro additions with 5-7 year gestation periods.

- The costs of solar PV systems have decreased rapidly over the past decade, and further cost decreases are likely. However, these gains are largely for the PV modules themselves, and balance of system costs will be more difficult to reduce. Nevertheless, present costs of $1,000/kW for floating systems are likely to reduce to $900/kW over the next decade.

- Much more rapid decreases in battery storage costs are probable over the next decade, driven by innovation for electric automobiles. Current storage costs are likely to decline to around $300-400/kWh by 2020.

- We anticipate no significant problems of grid integration associated with the variable output of PV. Even if the bulb turbines at LSS2 are less flexible than the Francis turbines at Longyangxia, and even if the grid cannot absorb short-term output fluctuations, battery storage systems will be able to mitigate this impact at relatively small incremental cost.

- While the PSSE modeling of system stability must be regarded as preliminary, since we lack the necessary details of the turbine-generator sets, the potential mitigation costs to ensure system stability may be limited to an additional circuit between LSS2 and the Stung Treng substation, and some reactive compensation.

- A floating PV system at LSS2 can be added without in any way detracting the ongoing hydro operations. Provided the present operator/owner of LSS2 is interested in the project, we see no insurmountable technical obstacles to a successful implementation.

- The main perceived risk will be the possibility of damage from intense typhoon storms, though these will have greatly diminished in strength by the time they might reach LSS2. However, engineering solutions are available to mitigate this risk.

A more detailed analysis of the economic and financial costs and benefits are presented below in Chapter 11.

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11 Economic Analysis

Sambor has long appeared as one of the locations for a hydro project on the Mekong mainstream, and in previous years the site has been proposed for the development of as much as 3,300 MW,[45] and most recently for a development of 2,600 MW as proposed in the feasibility study prepared by China Southern Power (CSP).[46] The Natural Heritage Institute (NHI) team examined some 10 alternatives ranging in scale up to 1800 MW before determining that the smaller alternatives presented in this Report stand the best chance of satisfying the environmental performance criteria that were specified to maintain the extraordinary natural resource values in the Sambor reach of the mainstream Mekong River. These alternatives are:[47]

- *Sambor Alt_7-A* mainstream project with maximum upstream and standard downstream mitigation: 1,236 MW, overnight capital cost US$2,626 million.
- *Sambor Alt_7-B*: same as Alt_7-A with new low impact turbine design: 1,051 MW, overnight capital cost US$2,715 million.[48]
- *Sambor Alt_7-C:* same as Alt_7-A *with coarse fish screens* to enhance downstream passage success: 1,236 MW, overnight capital cost US$3,626 million, of which US$1 billion is for the coarse screens.
- *Sambor Alt_7-D:* with maximum upstream *and* maximum downstream mitigation - coarse fish screens *and* a low impact turbine design, overnight capital cost US$3,715 million.
- *Sambor Alt_6*: in the Anabranch channel 125 MW, capital cost US$702 million.

These Sambor alternatives are compared and contrasted not just to the CSP design, but also with two hydro projects in the region currently under construction: the 250 MW Trung Son hydro project in Vietnam, and the 400 MW Lower Sesan 2 project in Cambodia, and to a 400 MW floating PV project at the Lower Sesan 2 (LSS2) hydro project.

The reduction in scale has significant implications for the cost and design of the project, not least of which are the design and cost of the power transmission facilities: a project of 2,600 MW scale would likely require several dedicated circuits of 500 kV HVAC (if not HVDC) to a major load center in either Thailand or Vietnam.[49] Whether the output of the somewhat smaller 1,800 MW Sambor project – implemented in three steps of 600 MW as proposed by the latest official plan – could be absorbed entirely by domestic demand growth was discussed in Appendix 10.2.

45 This was the installed capacity of the Sambor project included in one of the first hydro power assessments of the Mekong mainstream (Mekong Secretariat, 1994). It was seen at that time as having a reservoir area of 590 km^2, displacing 5,120 persons, and generating 14,900 GWh per year. It estimated an economic rate of return of 14.6%. As noted below, the number of persons presently estimated to be resettled is more than four time this figure.

46 *Feasibility Study Report of Sambor Hydropower Station*, China Southern Power Grid Co. & Guangxi Electric Power Industry Investigation Design and Research Institute, October 2008. This study is hereinafter cited simply as "CSP FS".

47 The costs cited here are exclusive of transmission connection costs. By *overnight* capital cost we mean the capital cost were all investment expenditures purchased on a single day, so without taking into consideration multi-year construction periods which incur additional costs due to interest during construction (on that component financed by debt), or price increases attributable to inflation.

48 See below for a description of what is meant by low impact.

49 The Cambodian grid is synchronized with that of EVN, allowing HVAC transmission (as proposed for Sambor CSP). For the somewhat longer distance from Sambor to Thailand, HVDC transmission may be more suitable.

Projects of the scale examined by the NHI team might however serve just the Cambodia grid with a relatively short 230 kV transmission connection: the 400 MW Lower Sesan 2 project is connected to the Electricity of Cambodia (EdC) grid by a 2 x 230 kV, US$92 million transmission line.[50] Table 11-1 summarizes the salient features of the five Sambor alternatives considered here, and the projects used as comparators.

Table 11-1. Salient features of the Sambor hydro project development alternatives.

Features	Units	Sambor Alt_7-A	Sambor Alt_7-B	Sambor Alt 7-C	Sambor Alt_7-D	Sambor Alt_6	Sambor CSP FS	Trung Son	Lower Sesan 2
Installed capacity	MW	1,236	1,073	1,236	1,073	125	2,600	250	400
Average annual energy	GWh	4,240	3,680	4,028	3,680	472	11,103	1,019	1,912
Reservoir area	Km^2	67	67	67	67		620		335
Power density	W/m^2	18.4	18.4	18.4	18.4		4.2		1.2
Construction cost (1)	$US million	2,873	3,021	3,873	3,021	732	5,159	451	874
	$/kW	2,324	2,816	3,133	3,748	5,836	1,984	1,084	2,185

(1) Overnight cost, including transmission and Relocation and Resettlement (R&R) costs

All cost estimates in this report, except where expressly stated to the contrary, are at 2016 prices.

The Methodology of Cost-Benefit Analysis and its Limitations

Background

Cost-benefit analysis has a long and distinguished history, and a correspondingly large literature.[51] However, over the last 20 years the practice of benefit-cost analysis as applied to hydro projects has seen important changes. The first is the increasing role of externalities, both positive and negative. The positive benefit of hydropower in avoiding greenhouse gas emissions of the thermal alternative is now routinely included in the assessment of a hydro project financed by one of the international financial institutions (IFIs).

But on the negative side, many large projects have experienced much faster rates of reservoir sedimentation than expected, resulting in the loss of active storage, and therefore reduced peaking power benefits. Both the Mahaweli and the Tarbela projects have experienced major problems.[52] Today, sediment management has assumed much greater importance even to the point of implementing flushing regimes that significantly reduce power generation.[53] In the Mekong basin,

50 This transmission connection is being constructed as a private project by subsidiaries of the Malaysian company Pestech under a 25-year agreement with EdC. We have not sighted the agreement in question, but annual wheeling charges are expected to be $12.2m for the first three years, $18.2million for the remaining 22 years. We have no details about the financing arrangements, but based on these figures as quoted in the Press, and assuming fixed operating costs of 2% of capital cost per year, the *project* FIRR calculates to 14%. The return on (leveraged) *equity* is likely to be well in excess of 20%.

51 The standard works on cost-benefit analysis in the development economics literature include Squire and van der Tak (1975), Gittinger (1982), and ADB (1997).

52 See, e.g., Gunnatileke and Gopalakrishnan (1999). This study concluded that upstream watershed management at the farm level (rather than reservoir de-silting) was the most effective control method, and that most of the economic losses were reductions in power generation.

53 The proposed flushing regime at the 4,600 MW Dasu project (Pakistan) will reduce generation by as much as 25%.

sediment capture is a concern not just to power generation through loss of active storage, but to the loss of downstream economic benefits attributable to loss of nutrients and deltaic replenishment.

Resettlement (in some cases involving very large numbers of people) was not in the past seen as a major equity issue for many Governments, and there were few NGOs to take up the concerns of the displaced. The Hoa Binh project in Vietnam required resettlement of 85,000 persons; the recently completed Son La hydro project resettled some 78,500 persons. The CSP design for Sambor would involve the relocation and resettlement (R&R) of over 20,000 persons, which would be by far the largest such endeavor to date in the LMB: whether an Independent Power Producer (IPP) would be willing to undertake R&R on such a scale is unclear. The point here is to emphasize that today, access to concessional finance for hydro projects is dependent upon adherence to the safeguards policies of the international financial institutions (IFIs).[54] To meet such requirements at Sambor would require R&R costs more than three times greater than those assumed by CSP.[55]

Limitations

Cost-benefit analysis (CBA) has several important limitations. The first is that while it can clearly answer the question of whether a project has positive *net* economic benefits, it cannot answer whether the inevitably uneven distribution of costs and benefits is justified: in the case of the CSP design for Sambor, we shall show that the net power benefits may be sufficiently large that they *exceed* the damage costs to the LMB fishery even in the worst case that all migratory fish passage is blocked at Sambor.[56]

But whether that trade-off is worth making is a matter for Government decision, not for economists. It would not be the first instance of a Government taking such a decision affecting fishing: the decision of the UK Government to open its fishing grounds to the EU as the price of entry is one such example.[57] The relevance of such examples to Sambor is clear: given the risks of severe damage to the Mekong river fishery, an effective benefit-sharing program for the downstream fishermen, with some part of project royalties ring-fenced for this purpose,[58] and under independent adjudication

54 There is no better example of the controversies that have characterized recent large hydro schemes in the region than the Nam Theun 2 project, which triggered almost all of the World Bank safeguards policies when the project requested the Bank's participation in the form of a partial risk guarantee (PRG). This involved the resettlement of some 6,200 people, and affected the livelihood of many thousands more.

55 See section on costs on page 11, below.

56 It is worth noting that it is not merely the downstream riparians that would be affected by Sambor: the CSP design will also have negative effects on the migratory fishery in the Xe Kong basin in Lao, and in the mainstream migratory fishery in both Thailand and Lao above Khone falls.

57 The Common Fisheries Policy was introduced by the EU in 1970, just before the UK, Ireland, and Denmark, countries with rich fishing grounds, joined. Critics of the policy at the time claimed that this was a resource grab by the existing members of the EU. However, Britain was so keen to join the EU (after a rejection by France a few years previously) that, according to archives since released, the UK negotiating position regarding the fishermen was along the lines "in the wider UK context, they must be regarded as expendable". See Rotherham (2009) and Swales *et al* (2006). However, the real failure has been that the UK government did not provide devastated fishing communities with proper assistance to generate alternative employment opportunities (only on the Scottish East Coast did the fortuitous growth of the North Sea oil sector provide economic revitalization – a development that had little to do with Government intervention to assist the declining fishing industry).

58 At a minimum, the amounts should be identified in the PPA, and paid by the IPP into a separate escrow account controlled by an independent entity accountable to a local or provincial government. However, identifying eligible fishermen in downstream areas is much more difficult than indentifying households who lose land or need to be resettled in the project area.

and management, is absolutely essential: achieving this in practice may prove very difficult indeed, particularly if implemented outside the framework of the environmental safeguards of the Equator Principles and the IFIs. Moreover, other Governments will also have a voice under the Procedures for Notification, Prior Consultation and Agreement of the Mekong River Agreement.

Indeed, the main question in making the trade-off is whether Governments have the capacity to share the benefits with those who are negatively affected. This has given rise to a separate literature on so-called "benefit sharing" at hydro projects (Wang, 2016; ICIMOD, 2016). Such payments are sometimes erroneously identified as costs (since where the hydro project is developed by an IPP, to the *IPP* such payments to local communities are indeed a financial cost). However, in economic analysis, payments that go beyond immediate compensation of loss to those displaced are not economic costs, but a sharing of the net economic benefits.[59] In the LMB, Vietnam is the first country to attempt formal benefit-sharing programs for hydro projects (Haas & Tung, 2007).[60]

The second limitation is that CBA requires a way to quantify and trade-off how society values costs and benefits in the short term, against costs and benefits in the long term: all investment projects require that resources are invested today (rather than consumed) in the hope of a greater returns (consumption) in the future. As a matter of algebra this is done through the discount rate – as discussed in more detail in Appendix 11.1. But, decision making is further complicated by two realities – first, that costs and benefits today (and in the short run) are relatively certain, whereas costs and benefits in the future tend to be uncertain (and in some cases, as in those associated with climate change, highly uncertain both as to their magnitude and their timing). Second, that experts and Government advisers often disagree on key assumptions, resulting in conflicting advice – indeed as well illustrated by conflicting views about the adequacy of fish protection measures at Mekong hydro projects presently under construction.

These matters of decision-making under uncertainty are taken up in the next Chapter of the report on Risk Assessment: one of the central ideas being that projects with high expected returns often have high risk, while projects with low risk tend also to have low returns. As shown in this report, the CSP design for Sambor has high return but also high risks; the Sambor Alt_7-A option has much lower risk (though still potentially large when the uncertainties in the mitigation measures are taken into account), but correspondingly lower returns.

Previous Studies

Seven noteworthy prior studies that have reported on the economics of hydro projects in the LMB, and in particular on projects on the Mekong Mainstream, require attention as background information (and are cited at various points below):

- *The MRC Assessment of Basin-wide Development Scenarios* (MRC, 2010). The report assumes a 3,300MW installed capacity for Sambor. We cite this report simply as "*BDP2*".

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59 In the vocabulary of economic analysis, these are denoted as *transfer payments (*as are all taxes, import duties and VAT*)*.

60 In 2007, the Electricity Regulatory Authority of Viet Nam (ERAV) developed a draft Decree Law for a Benefit Sharing Mechanisms on hydropower: In 2010, provisions of the law were pilot tested on a 210 MW project in Quang Nam Province in cooperation with the provincial authorities.

- The "Costanza Report" (Costanza *et al*, 2011): a critique of the BDP2 studies, which notes the BDP2 uses optimistic assumptions about reservoir fisheries and aquaculture to offset impact on downstream capture fisheries.
- *The Revalidation of Costanza* (Intralawan *et al*, 2015). This report, published in November 2015, revisited the original Costanza report,[61] and presented new calculations for the 11 mainstream dams scenario of BDP2. While the power benefits were left unchanged, externality damage costs were based on revised assumptions on valuation, discount rates, and time horizons. We cite this report as "*Revised Costanza".*
- A more recent "update" of the Revised Costanza report (Intralawan, Wood and Frankel, 2017), which (wisely) reverts to the same 10% discount rate as used in BDP2, but which dramatically reduces the hydropower benefits. This reported is cited as "NREM".[62]
- *Strategic Environmental Assessment of Mekong Mainstream Hydropower*, by ICEM (cited as MMHSEA).
- *Guidelines for the Evaluation of hydropower and multi-purpose project portfolios: Annex I: Economics Practice Guide* (MRC, 2015).[63] Notwithstanding its title, this is more of a literature review of past studies in the Mekong Basin regions than a guide to CBA – indeed the principles of CBA for hydro projects have been extensively recorded and hardly need restatement.
- *The Mekong Delta Study (MDS, 2015)* prepared for Vietnam's Ministry of Natural Resources and Environment (MONRE). This study also estimates the cumulative economic impact of all of the proposed mainstream hydro-projects including the impact on GDP, but limits the quantitative economic analysis to fishery impacts and on rice production.

The conclusions of the Costanza, Revised Costanza and NREM reports are reviewed in detail in Appendix 11.1. While these past studies come to conclusions not materially different to those derived here with regard to the likelihood of significant negative impacts on the LMB fishery, their assumptions and methodology require rejoinder (notably the selective use of discount rates, and a lack of transparency in calculations).

Power Purchase Agreement (PPA)

Although conceptually possible, in practice it is highly improbable that a hydro project in Cambodia could be financed on a "merchant" basis, selling into wholesale spot power markets, as has been established, for example in the Philippines, or into the competitive wholesale market being planned for Vietnam. For the purposes of this report, it is a basic assumption that the Sambor project, of whatever size, will be developed and financed on the basis of a long-term power purchase agreement (PPA). At the time of writing we have sighted neither the concession agreement nor the PPA for the Lower Sesan 2 hydro project, but we understand the concession agreement provides for a 40-year term, after which the project would be handed over to the Government.

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[61] Two of its three authors are listed as co-authors of the Costanza Report.

[62] Which is how the authors themselves refer to their study, given their institutional affiliation with the Natural Resources and Environmental Management Research and Training Centre of Mah Fah Luang University, Thailand.

[63] MRC Initiative on Sustainable Hydropower, *Guidelines for the Evaluation of Hydropower and Multi-purpose Facilities*, Mekong River Commission Secretariat November 2015.

China Southern Proposal for Sambor

The most detailed study of a large hydro project at Sambor is the feasibility study by China Southern Power Company (CSP FS), a conventional design with the sole objective of maximizing power output with little attention to minimizing or mitigating externalities. At 2,600 MW of installed capacity, and annual energy of 11,103 GWh, this is a very large project with low unit production costs (as estimated below, of around 6.8 USc/kWh at 2016 prices).[64] The FS envisaged export to Vietnam with a 2 x 500 kV transmission to the Ho Chi Minh City area.

The fish passage provisions of the CSP FS are very far from international best practice: even as a conventional fish passage the design would unlikely meet the average performance reported in the literature. With a very large reservoir, some 62% of sediment will be captured,[65] with very significant impacts on the Mekong delta; by contrast, Sambor Alt_7-A will capture only some 7%.

Nevertheless, the CSP design serves as a useful comparator for the Sambor Alternative designs. Its costs are at 2008 price levels, which need to be updated to 2016 prices. These would have been derived very near the height of the speculative commodity price boom that also affected construction costs. The Manufactured Unit Value (MUV)[66] index published by the World Bank shows a value of 102.83 in 2008, falling to 96.46 in 2009, but since then increasing, reaching a value of 106.65 in 2016.[67] Assuming 60% FOREX[68] and 40% local currency, and local currency portion increasing at the Cambodian rate of inflation, the average price adjustment factor is 1.13. For comparative purposes, we subtract the original estimate for relocation and resettlement costs (R&R): the updated NHI estimates are added back in below. The adjusted cost is US$4.55 billion (Table 11-2).

Table 11-2. Adjusted cost of the CSP Sambor design.

	$US million
FS cost estimate (excluding financial costs)	3,592
Less R&R costs	-70
Engineering cost estimate	3,522
Assumed annual rate of inflation	3%
Number of years from 2008 to 2016	8
Factor	1.27
Escalated cost	4,550

The consequences of such a project on downstream fisheries is examined in more detail in the sections below: as noted, even were the LMB fishery that presently migrates across the Sambor dam site entirely lost, the magnitude of the project and the low cost of power generation generates correspondingly large net economic benefits, that could more than offset the loss of fisheries.

64 The output of the CSP design has been quoted by some sources at the somewhat greater figure of 11,741 GWh. However, the CSP FS clearly defines 11,103 GWh as "electricity to the power network" and "supplied electricity".

65 All other things equal, the larger the reservoir, the lower the average velocities, and hence the greater the propensity of sediments to settle.

66 http://data.worldbank.org/data-catalog/MUV-index

67 The value for 2016 is a forecast.

68 The share of electromechanical and metal structure equipment (gates etc) is 35%. However, given the level of industrialization in Cambodia, one would anticipate a substantial foreign share of other cost items as well.

However, whether so large a project can actually be achieved in practice is doubtful. We note the following:

- A single loan, as was possible for the 400 MW LSS2 project (from the China Development Bank), would imply a loan commitment of US$4.7 billion,[69] more than 10 times greater than the US$547 million for LSS2. The level of risk in such a much larger project makes a syndication arrangement (such as at Xayaburi) inevitable.[70]
- The CSP FS correctly notes the advantages of IFI participation (suggesting the ADB as the main finance source). However, the chances that ADB would finance Sambor given the probable degree of opposition from the downstream riparian is small (and in the case of the World Bank, absolutely zero). Neither the ADB (nor the World Bank) would provide the entire US$4.7 billion. The most recent ADB financed hydro project in Laos had to agree to implement all of the ADB environmental and social safeguards, under the oversight of Independent Advisory Panel to monitor the Project's compliance (see Text Box 11-1 for details of this project).
- If commercially financed, one alternative would be to lower the cost of that debt through a partial risk guarantee (PRG) from the World Bank.[71] However, that would still require compliance with all of the World Bank safeguards policies; that for a project on an international waterway includes a "no objection" certification from the downstream riparian. It seems unlikely that this could be obtained from Vietnam without inordinate delays, if indeed at all.

Text Box 11-1: The Nam Ngiep 1 Hydro project in Laos.

A good example of a project in the region that has obtained ADB financing of a private/public partnership hydro project is the Nam Ngiep 1 hydropower project in Laos. This project was approved by ADB in 2014, and is now under construction, with expected start of operation in January 2019.[72]

The project involves construction and operation, on a build–operate–transfer basis, of a 290 MW hydroelectric power generation facility, on the Nam Ngiep River, in the provinces of Bolikhamxay and Xaysomboun. The dam site is 145 kilometers (km) northeast of Vientiane. It has three major components:

i. a main power station (272 MW) with a concrete gravity dam (height 148 meters) and a reservoir (surface area 67 square kilometers), with effective storage capacity of 1.2 billion cubic meters; electricity produced will be exported to Thailand;
ii. a reregulation power station (18 MW) with a concrete gravity dam (height 21 meters) and a reregulating reservoir (surface area 1.3 square kilometers), with effective storage capacity of 4.6 million cubic meters; electricity produced will be supplied within the Lao PDR;6 and
iii. a 125 km 230-kilovolt (kV) transmission line to connect the main power station to the Nabong substation near Vientiane.

The Nabong substation is already connected to the Udon-Thani substation in Thailand by a double-circuit transmission line. The Nam Ngum 2 (NN2) hydropower project installed the Lao PDR side of this transmission line and EGAT installed the line on the Thai side. It is currently energized at 230 kV and transmits NN2's power to Thailand. NN2 will upgrade the substation by the time of NNP1PC's interconnection, and the transmission line will then be energized at 500 kV. The government through Electricité du Laos (EDL) will purchase these facilities

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[69] The total overnight cost including transmission is $5.2 billion (Table 11-6). To this must be added some $1.1billion in capitalized interest during construction for a total of $6.3 billion. Assuming 30% equity (as at LSS2) this implies a debt of $4.4 billion!

[70] The Xayaburi financing involved a consortium of six Thai commercial banks to raise 80 billion Baht ($2.2 billion).

[71] As for example, provided for the Nam Theun 2 project in Laos.

[72] ADB, *Proposed Loans, Nam Ngiep Hydropower Project, Lao People's Democratic Republic, Report and Recommendation of the President to the Board of Directors*, Project 41924, July 2014.

from NN2 for integration into the national grid. After the transfer, NNP1PC and NN2 will enter into an interconnection agreement with EDL and pay wheeling charges for use of the facilities. EDL will engage EGAT to operate and maintain the Nabong facilities.

The equity consortium is as follows:

- EGAT (30% of equity)
- Government of Laos, though the Lao Holding State Enterprise (25%)[73]
- Kansai (Japanese utility) through a Netherlands company: 45%

Raising a total of $336 million (so 34.2% of total capital cost).

The breakdown of debt finance is

- ADB direct loan of %50 million from ADB's ordinary capital resources
- ADB B loan $ 77 million funded from participating commercial banks;
- Local currency loan of Thai Baht 3.04 billion (or its equivalent in US $ if Baht are not available)
- JBIC loan $197 million
- Thai commercial banks: $228 million equivalent (in Baht).

The total estimated cost is US$982 million.

- The scale of required resettlement (over 20,000 persons) is 10 times greater than at Xayaburi, and four times greater than at LSS2. The inevitable controversy will raise reputational risks to lenders. This may be of low concern to Chinese banks, but will be an important issue for IFIs or other international commercial lenders committed to the Equator Principles.[74]
- A mainstream dam so close to Vietnam, where the negative downstream impacts will be more readily observable and demonstrable, will provoke very strong objections in Vietnam. The rice paddies of Vietnam's Mekong delta region have the same existential importance to the Government of Vietnam as do the Tonle Sap fisheries to the Government of Cambodia. The scale of opposition in Vietnam to a large conventional dam at Sambor will not dissipate as easily as Vietnam's earlier opposition to Xayaburi. One should expect vigorous objections from Vietnamese NGOs and the affected Provincial Peoples Committees. Notably, any scale of Sambor Dam will have to undergo the plenary inter-governmental vetting process prescribed in the Procedures for Notification, Prior Consultation and Agreement under the Mekong River Agreement. While this does not give the Governments of Vietnam, Lao PDR or Thailand a veto over the project as a practical matter, it would make it quite difficult for the RGC to prevail over the objections, the vigor of which will likely be proportionate to the project's scale and impact on migratory fisheries and sediment flows.
- The scale of the project is such that its output far exceeds the likely ability of the Cambodian power system to efficiently absorb it, as discussed further in Appendix 10.2. The Thai commercial banks have a demonstrated appetite for lending to hydro projects that have

73 This is a holding company established by the government of Laos to own and manage equity investments in power projects. Since Nam Theun 2 was commissioned in April 2010, LHSE has started receiving regular dividend revenue.

74 The Equator Principles is a risk management framework, adopted by financial institutions, for determining, assessing and managing environmental and social risk in projects. (http://www.equator-principles.com). Currently 89 Institutions in 37 countries have officially adopted the Principles, covering over 70 % of international Project Finance debt in emerging markets. Indeed, recent adopters have included the Korean Development Bank, and the Jiangsu Bank of China.

PPAs with EGAT, and EGAT is certainly a creditworthy off-taker, but whether the past interest would extend to a project of this size is unclear.[75]

- With the cancellation of Vietnam's nuclear power program as was envisaged by the most recent 7th Power Development Plan, and if current demand forecasts are realized, then a significant supply gap will occur in Vietnam in the late 2020s and early 2030s (see Text Box 11-2). But nuclear power provides base load, not peaking power, so it remains unclear whether EVN would be prepared to enter into a 20-year PPA with a private developer at Sambor. Moreover, the likely opposition of Vietnam to a large Sambor project would make the optics of such an agreement very difficult. Moreover, the construction time for a large Sambor project is at least 6-7 years, not very different to the construction time of a nuclear project, making any immediate the commitment by Vietnam to a PPA even more problematic: with the official plan calling for the first 600MW at Sambor in 2025,[76] the PPA would need to be signed in 2018.
- The LSS2 financing model that obtained a sovereign guarantee from the RGC may well work again for smaller scale project whose main benefit is meeting domestic demand at low cost, but a similar guarantee for the 2,600 MW version of Sambor implies a guarantee that is *five* times larger than LSS2. The headroom for such a level of sovereign guarantees is unclear.
- With the wholesale generation market soon to arrive in Vietnam, that would allow use of the transmission grid for IPPs to sell directly to wholesale customers, lack of interest from EVN may matter less. But it seems unlikely that so large a large project whose projected revenues are based solely on competitive market transactions in Vietnam would be bankable.

The latest official power development master plan of the RGC[77] includes a hydropower project at Sambor of 1,800 MW, implemented in three stages of 600 MW, the first stage in 2025, with a further 600 MW in 2026, and a third in 2027. This is based the largest of the 10 Sambor dam options screened by NHI in the early phases of our work and presented to The Minister of Mines and Energy on March 28, 2016 as a "proof of concept". At that point in the project, NHI regarded it as leading option because it was the largest facility that could be operated to successfully discharge sediment. At that time neither the construction costs of the project, nor the detailed modelling of fishery impacts and reservoir velocities, had been completed. Indeed, with an annual energy of 5,200 GWh, the capacity factor works out at 33%, far too low to be economic (Sambor CSP has a capacity factor of 49%, LSS2 of 55%, and our final proposal for Alt-7A of 39%). Moreover, subsequent hydrodynamic modeling of the reservoir revealed that it would not be possible to maintain a flow velocity within the reservoir sufficient to keep the eggs and larvae from the upstream spawning in suspension all the way to the point of discharge, especially during the drier periods of the year, without lowering the storage levels to a point where the project was no longer viable from the power generation standpoint. With substantially higher construction costs, low energy, and

75 In both Vietnam and Thailand, over the past few year the growth of peak load has grown much less than the growth in 600MW unit in 2025energy, as the daily load curve flattens out due to growth in air conditioning loads. This reduces the pressure to commission ever more peaking projects.

76 See Appendix 10.2.

77 Issued 22 September 2016.

difficulties in achieving the environmental objectives, the 1,800 MW Sambor variant was not studied further.

Costs

Transmission Arrangements

The inability to synchronize the grids of the LMB hydro exporters remains a major hurdle for an efficient design of regional power trade in the region. All of the major export projects now being considered in Laos, such as the 1,285 MW Xayaburi project (mainstream Mekong in Laos, also serving EGAT), require dedicated transmission lines synchronized to the importing country: for example, power from a series of hydro projects in Laos will be evacuated by a line connected to the Vietnam 500 kV grid at Pleiku.[78] Fortunately, the EdC grid centered on Phnom Penh is already synchronized with the Vietnamese grid, and indeed Cambodia presently imports significant quantities of electricity under the terms of a Government-to-Government agreement (see Text Box 11-2).[79]

A detailed evaluation of the power evacuation arrangements goes beyond the scope of this study. Table 11-3 shows the assumptions made here: the transmission costs are included in the capital costs of each project.

Table 11-3. Transmission connection costs.

	MW	$US million	
LSS2	400	92	actual, per PPA
Sambor CSP FS	2,600	395	CSP FS, updated to 2016 prices
Sambor 7A, 7B,7C	1,025	180	NHI estimate
Sambor 6	125	30	NHI estimate
Counterfactual CCGT		180	NHI estimate
Floating PV at LSS2	400	10	See Chapter 10 for details

The presumption is that the connection costs for the counter-factual LNG CCGT are the same as for Alt_7-A (the location of the CCGT is assumed to be on the Cambodia coast, roughly the same distance to the major Phnom Penh load center) as the Sambor projects (Figure 11-1).

78 This project will evacuate power from the Sekong and Sekamen hydro projects in Laos, first to a substation at Ban Sok, then by a 100 km line to the Pleiku substation in Vietnam (ADB, 2008).

79 However, as noted in Appendix 10.2, Cambodia's dependence on imports from Vietnam have already reduced, and will be almost entirely eliminated once LSS2 is at full production.

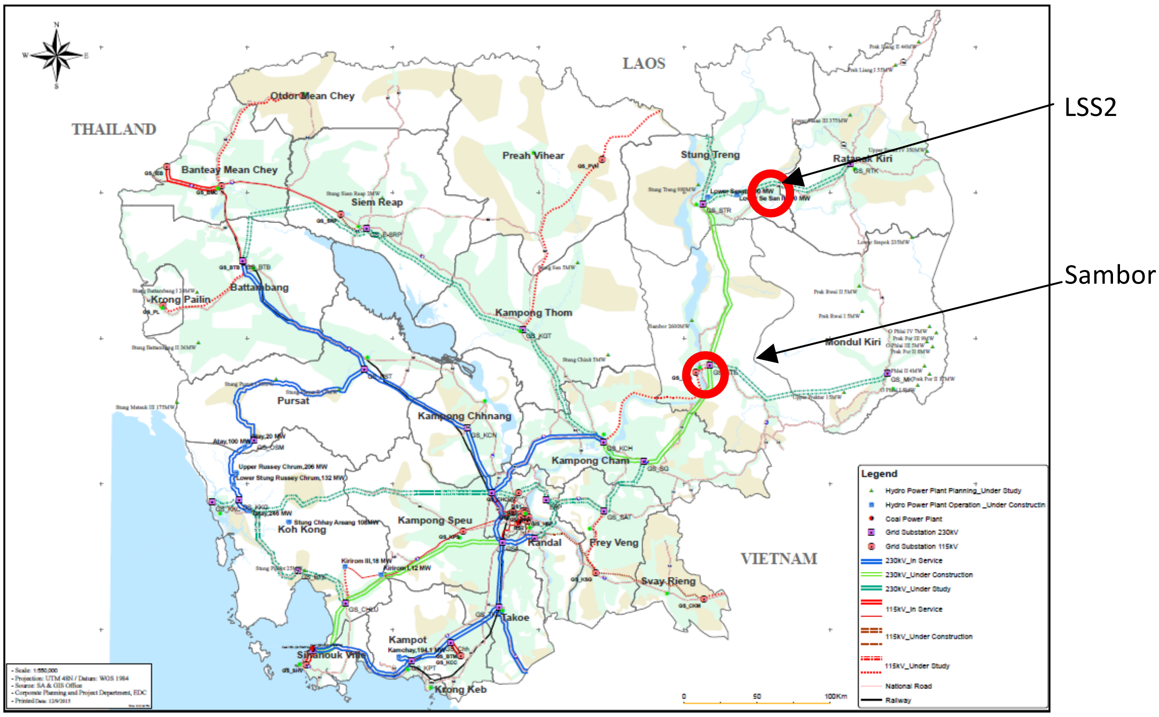

Figure 11-1. Transmission System in 2014. Source: EdC Annual Report (2014).

The transmission cost of the CSP Sambor option is high, because the scale of the output implies export, assumed by the FS to be Vietnam (3 x 500kV, 260 km to Ho Chi Minh City). The CSP FS assumes this could be recovered through a wheeling charge of 0.74 USc/kWh (at 2008 prices). No such implementation assumptions are necessary in this report: for the *economic* analysis, whether implemented by a separate IPP (as for LSS2), or a Public-Private Partnership (PPP)[80] or by EdC, does not matter.

[80] For hydro projects, such PPPs take the form of a special purpose vehicle, with majority private ownership, but where Government has some equity share held either by a state-owned utility (such as EdC), or another entity established expressly to hold Government shares in hydro PPPs (as in Laos).

Text Box 11-2. The Cambodia energy sector: salient features.

The development of hydro projects at Sambor must be placed in the context of the overall size and development prospects of the power sector. The latest published EDC annual report shows rapid growth in peak demand of the main grid - from 805 MW in 2014 to 2,678 MW in 2025, and 4,950 GWh in 2014 to 14,951 GWh in 2025, an annual growth rate of 10.5%.

EDC Demand forecasts

Base Case	2014	2020	2025
Peak in Main Grid (MW)	805.84*	1,681	2,678
Peak in Whole Country (MW)	887	1,681	2,678
Energy in Main Grid (GWh)	4,511.79*	9,406	14,951
Energy in Whole Country (GWh)	4,954	9,406	14,951

Source: EDC Annual report, 2014.

In the past, Cambodia has imported a significant proportion of its electricity from Vietnam, with smaller imports from Thailand and Laos. With the expected commissioning of LSS2, the 135 MW coal project in Sihanoukville and the 108 MW Stung Chey hydro project, the proportion of imports from Vietnam is expected to fall sharply over the next few years. Appendix 10.2 provides further detail on the past development of the Cambodia power system and scenarios for its future development.

Composition of energy inputs, GWh

	2012	2014
National grid	2790	5411
Kampot-Sihanouk Grid	115	
Kampong Cham Grid	42	
Vietnam	319	401
Thai	143	169
Lao	9	19
Isolated systems	29	12
captive industry	72	3
total	3519	6015

Source: Annual reports of the Electricity Authority of Cambodia.

Relocation and Resettlement

Resettlement (in some cases involving very large numbers of people) was not in the past seen as a major equity issue for many Governments, and there were few NGOs to take up the concerns of the displaced. The Hoa Binh project in Vietnam required resettlement of 85,000 persons; the recently completed Son La hydro project resettled some 78,500 persons. The CSP design for Sambor would involve the relocation and resettlement (R&R) of over 20,000 persons, which would be by far the largest such endeavor to date in the LMB: whether an Independent Power Producer (IPP) would be willing to undertake R&R on such a scale is unclear. The point here is to emphasize that today, access to concessional finance for hydro projects is dependent upon adherence to the safeguards policies of the international financial institutions (IFIs).[81] To meet such requirements at Sambor would require R&R costs more than three times greater than those assumed by CSP.[82]

81 There is no better example of the controversies that have characterized recent large hydro schemes in the region than the Nam Theun 2 project, which triggered almost all of the World Bank safeguards policies when the project requested the Bank's participation in the form of a partial risk guarantee (PRG). This involved the resettlement of some 6,200 people, and affected the livelihood of many thousands more.

82 See section on costs on page 11, below.

The Alt_7-A and CSP concepts for Sambor would displace significant number of persons. The 2008 CSP FS estimated 19,035 persons would require resettlement, but NHI's estimate for the CSP FS in 2016 is 21,442 persons. As shown in Table 11-4, these are at the high end of the range of other potential Mekong Basin projects: only Ialy (Vietnam) is of comparable magnitude in numbers of persons resettled.

The Sambor Alt_7-A design has a substantially smaller reservoir, and correspondingly fewer persons would require relocation and resettlement, estimated at 6,660 persons. The Sambor Alt_6-A design requires the displacement of just 2,150 persons.

Table 11-4. Estimated resettlement numbers of LMB hydro projects.

		MW	persons resettled	$/person
Ialy	Vn	720	**24,610**	1,463
Sambor CSP, revised to 2016	**Cambodia**	**2600**	**21,440**	**10,000**
Sambor CSP	**Cambodia**	**2600**	**19,035**	**3,680**
Nam Tha 1	Laos	168	8,249	4,243
Nam Theun 1	Laos	521	6,844	2,630
Sambor Alt_7A/B/C/D	**Cambodia**	**1085**	**6,660**	**10,000**
Nam Ngum 2	Laos	615	5,759	3,646
Nam Theun 2	Laos	1070	5,500	5,636
Pleikrong	Vn	100	5,451	2,935
LSS2 [Estimate]	**Cambodia**	**400**	**~5,000**	**[?]**
Buon Kuop	Vn	280	4,418	453
Nam Ngum 1	Laos	164	3,500	1,429
Nam Khan 3	Laos	60	3,353	1,491
Nam San 3	Laos	48	2,832	3,531
Houay Ho	Laos	152	2,500	800
Trung Son	**Vietnam**	**210**	**2,285**	**10,000**
Sambor Alt_6	**Cambodia**	**125**	**2,115**	**10,000**
Xayaburi	Laos	1280	1,720	13,953
Nam Hinboun	Laos	45	1,200	10,000
Nam Mang 3	Laos	40	1,200	4,167
Xakaman 1	Laos	290	1,094	5,484
Xekong 3up	Laos	145	1,080	6,481
Nam Ngum 5	Laos	120	994	6,036
Nam Ou 5	Laos	240	910	5,495
Srepok 3	Vn	220	899	7,786
Xepian-Xenam	Laos	390	800	7,500
Nam Pha	Laos	131	480	16,667
Srepok 4A	Vn	64	354	16,949
Se San 4	Vn	360	249	28,112
Xekong 3d	Laos	91	240	20,833
Nam Ou 6	Laos	180	210	4,762

Source: MRC database, Sambor estimates Alternatives &CSP

In any event the international experience suggests that estimates of the number of persons to be resettled made at the time of project appraisal are almost always significantly understated. A review by the World Commission on Dams (WCD, 2016) provides many examples of this: for example, at the Pak Mun project in Thailand, 241 families were counted as displaced when construction started in 1991. By the time construction was completed some 1.459 households had to be relocated. By 2000 the Thai Government had paid compensation to some 6,204 households. This may be seen as an unrepresentative extreme example, but the point remains – in the international experience, estimates are almost always understated,[83] so prudent cost estimates should provide for above-

[83] The WCD review showed that in projects funded by the World Bank, the actual number of people to be resettled was 47% higher than estimated at appraisal. Among the detailed case studies prepared by the WCD review, an average of 35% more people were resettled than initially planned.

average contingencies for R&R costs (and in the risk assessment of Chapter 12, we provide for uncertainty both in numbers to be resettled as well as the cost per person.

Average R&R cost per person of projects in the MBC database (excluding Sambor) is US$7,580/person. But price levels and reliability of these estimates vary. The CSP Sambor estimate or 19,035 persons is US$70 million, so just US$3,680 per capita.[84] The CSP FS lacks detail on what actions were actually contemplated.

The most reliable recent data is that for Trung Son, currently under construction, for which the relocation and resettlement cost is US$35 million for 2,285 persons, so US$15,317/person. However, a substantial fraction of this is for compensation for the additional 4,817 persons affected by the wider World Bank definition of "Project Affected Person" (which includes not just households actually resettled, but includes any person whose standard of living or livelihood is adversely affected even if relocation is not required). US$10,000/person is the baseline assumption used in this analysis for all the options, including the CSP FS design. In the case of IFI financing, this figure may well be much greater.

Sambor Alt_7-C and Alt_7-D (new turbine design)

In 2015, the MRC reviewed the state of knowledge on the effectiveness and economics of so-called fish friendly turbines[85] (Nielsen, Brown and Deng, 2015), as an alternative to conventional Kaplan turbines that are the indicated choice for the head and discharge conditions for Mekong mainstream hydro projects.[86] Several such designs have been proposed including the Alden turbine, and the Voith minimum gap runner (MGR) designs. The title of the MRC review notwithstanding, there are few specifics about differences in costs and efficiency. Such experience as has been established is for salmonid species in the US Pacific Northwest and the Alden turbine has yet to be demonstrated at commercial scale. The Alden turbine has been under development by the US Department of Energy and the Electric Power Research Institute (EPRI) since 2009 (EPRI, 2011). Such a design would involve thicker blades and slower rotation, but may well incur additional costs and an efficiency penalty. Over a range of species of interest to US applications, survival for juvenile fish are predicted to be as high as 98% (compared to less than 85% for Kaplan and Francis turbines) – though these results have yet to be demonstrated at commercial scale.[87] The MRC review suggests that the Voith MGR design might be achievable at full scale with comparable costs and efficiencies.

The MRC review proposes that a fish-friendly turbine (e.g., an Alden turbine) be installed on a hydro project in the LMB as a pilot demonstration. This would both allow research to be carried out and raise the profile of this approach to improving survival rates for downstream fish passage, perhaps at a carefully selected Mekong River tributary. This would be an important step in the eventual development and production of Alden turbines of a size suitable for the mainstream Mekong River

84 Broken down as US$53 million for "resettlement compensation for villages", US$13.7 million for "resettlement planning," and US$3.3 million for "allowances" (presumably contingencies).

85 Low impact turbines have no precise definition, but compared to conventional Kaplan turbines, have larger rotating diameter Slower rotational speed Reductions in the number of turbine blades Reductions in gaps between moving and fixed parts Thicker leading edges on blades, vanes and gates.

86 A review reveals that 10 of 11 designs for LMB hydro projects would use Kaplan turbines.

87 The species modeled include Alewife, Coho Salmon, White Sturgeon, Smallmouth Bass and Rainbow Trout.

plants. However, prior to such an application, fish passage testing, including the effects of barotrauma, needs to be carried out at a suitable prototype site.

The assumptions we make here are necessarily preliminary; the intent being to establish whether the incremental costs are likely to result in a cost-effective reduction in fishery damage costs. If so, then this would need more detailed study at the feasibility study stage. The following baseline assumptions are made:

- Incremental capital costs of US$148.6 million, based on postulated increases to the construction cost line items is shown in Table 11-5. This results in an increase in the total overnight cost for Sambor Alt_7-A of some 5.0%.
- A generation penalty of 14%, so average annual generation of 3,680 GWh rather than 4,240 GWh.[88]

Table 11-5. Incremental capital cost of improved turbines.

		Sambor Alt_7-A	Increase	Sambor Alt_ 7-C
[1]	Metal structures	125	10.0%	12.5
[2]	Auxiliary civil works	71	10.0%	7.1
[3]	Power house	90	10.0%	9.0
[4]	Turbine			120
[5]	total incremental cost			88.6

Note: row [4] assumes an incremental cost of $5 million for each of the 24 turbines.[89]

Capital Costs

Table 11-6 and Figure 11-2 show the overnight capital costs for the Sambor options considered in this report, together with LSS2 and Trung Son (Vietnam) as comparators. These are overnight economic costs (i.e. exclude any taxes and duties, or interest during construction) – except for LSS2 for which only the completed financial cost is publically available.

Table 11-6. Capital investment costs.

			Sambor							
			Alt_7-A	Alt_7-B (7A+new turbines)	Alt_7-C (7A+ screens)	Alt_7-D (7A+new turbines+ screens	Alt_6	CSP	Trung Son 250MW	LSS2
			[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
[1]	installed capacity	[MW]	1,236	1,073	1,236	1,073	125.4	2,600	250	400
[2]	overnight cost	[$/kW]	2,125	2,586	2,125	2,586	5,428	1,750	1,304	1,955
[3]	capital cost	[$USm]	2,626	2,775	2,626	2,775	681	4,550	326	782
[4]	R&R	[$USm]	67	67	67	67	21	214	35	
[5]	fish screens	[$USm]			1,000	1,000				
[6]	transmission	[$USm]	180	180	180	180	30	395	90	92
[7]	total overnight cost	[$USm]	2,873	3,021	3,873	4,021	732	5,159	451	874
[8]		[$/kW]	2,324	2,816	3,133	3,748	5,836	1,984	1,804	2,185

88 Preliminary model-scale tests of the Alden-Voith turbine suggests that efficiencies may be close to those of conventional turbines (Dixon, 2015). However, an Alden turbine will have a lower power capacity and less flow than a Kaplan turbine of the same diameter: preliminary information suggests this differential is about 12-14%. Alden estimates that a Kaplan provides approximately 13.5% more flow and 12.3% more power capacity than an Alden unit with the same diameter. The same output and discharge could be delivered by increasing the number of Alden turbines. However, this would require a detailed engineering optimization that lies outside the scope of this interim report: there would also be implications for the powerhouse design.

89 Based on preliminary information from Alden, relative to a conventional Kaplan turbine of comparable diameter.

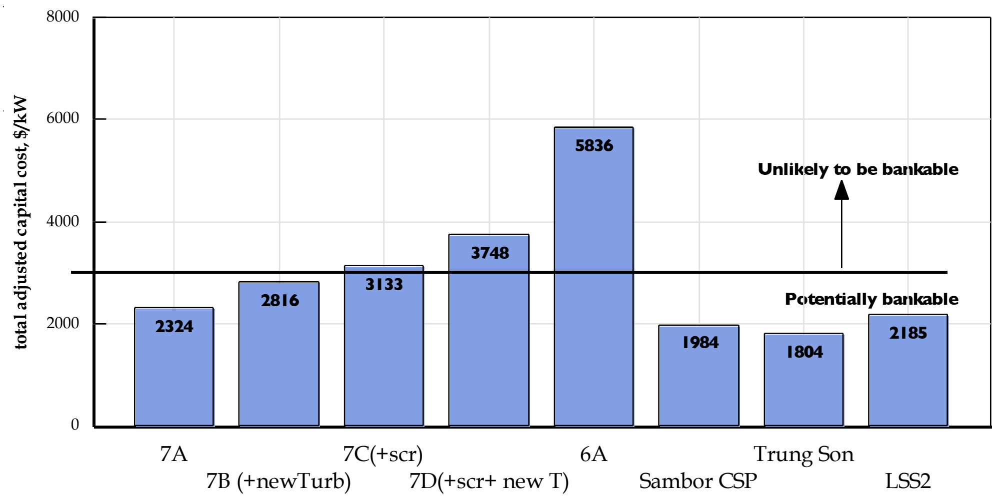

Figure 11-2. Capital investment costs.

Table 11-7 compares these costs to a wider sample of hydro projects in the recent international experience. The Sambor Alt_6 option is clearly unlikely to be feasible; very few hydro projects costing significantly more than US$4,000/kW prove to be bankable (and the projects in Table 11-6 above US$3,000/kW all benefitted from concessional finance from the IFIs, finance certainly unlikely to be available to a mainstream project at Sambor).

Table 11-7. Comparison with other hydro projects.

		MW	$USm	$/kW
Felou	Mali	60	176	4,017
Gulpur	Pakistan	102	365	3,578
Bujagali	Uganda	250	891	3,564
Muzzizi	Uganda	445	117	2,617
Karot	Pakistan	720	1,700	2,361
Sambor Alt 7A	**Cambodia**	**1236**	**2,873**	**2,324**
LSS2	**Cambodia**	**400**	**874**	**2,185**
Vishnugad	India	444	922	2,077
Sambor	**Cambodia**	**2600**	**5,159**	**1,984**
Jiangxi	China	120	209	1,742
Vietnam	**Trung Son**	**260**	**411**	**1,581**
Laos	NT2	1,070	1,450	1,355
Memvele	Cameroon	200	260	1,300

Source: For projects *not* in Cambodia, World Bank project appraisal documents.

Whether the options with new turbine design (Sambor Alt_7-B and Alt_7-D) are presently bankable is less clear. Such turbines may well be technically feasible at the costs indicated, but have yet to be demonstrated at commercial scale, and their certification will involve considerable time and expense. IPPs may be reluctant to commit to a new design that lacks significant commercial scale experience elsewhere.

Levelised Cost of Energy (LCoE)

Definitions

Levelised cost of energy is widely used to compare projects. It is also widely misused, for the simple reason that comparison of costs is only of value if the same level of *benefits* is provided. LCOE is defined as follows

$$LCOE = \frac{\sum_i \frac{I_i + O_i + V_i}{(1+r)^i}}{\sum_i \frac{E_i}{(1+r)^i}}$$

where

I_i	=	Capital expenditure in year i
E_i	=	Net energy production in year i
r	=	Discount rate
i	=	year, running from 1 to N where N is the economic life
V_i	=	Variable operating costs (including fuel, if any) in year i
O_i	=	Fixed operating costs in year I (including any major maintenance and life extension outlays

Normally, LCOE is presented as the *economic* LCoE at constant prices, which definition is used in this report.

LCoE Comparisons for Hydro Alternatives

The levelised cost of energy for the various hydro options, before consideration of externalities, is shown in Table 11-8 and Figure 11-3. The CSP has the lowest levelised economic cost of energy at 6.8 USc/kWh, compared to 9.1 USc/kWh for the Sambor Alt_7-A design. Fish screens and new turbines further increase the costs to as much as 14.7 USc/kWh for Sambor Alt_7-D.

Table 11-8. Levelised economic cost of energy, USc/kWh – before environmental damage costs.

			Sambor							
			Alt_7-A	Alt_7-B (7A+new turbines)	Alt_7-C (7A+ screens)	Alt_7-D (7A+new turbines+ screens	Alt_6	CSP	Trung Son 250MW	LSS2
			[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
[1]	Capital cost, overnight	[$USm]	2,873	3021	3873	4021	732	5,159	451	874
[2]	Construction period	[years]	4	4	4	4	3	6	4	
[3]	IDC adjustment	[ ]	460	484	621	644	76	1,475	72	
[4]	Total capital cost	[$USm]	3,333	3,505	4,493	4,666	807	6,635	523	874
[5]	Energy	[GWh]	4,240	3,680	4,240	3,680	472	11,103	1,019	1,912
[6]	Annual load factor	[ ]	0.39	0.39	0.39	0.39	0.43	0.49	0.47	0.55
[7]	Life	[years]	40	40	40	40	40	40	40	40
[8]	Discount rate	[ ]	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
[9]	Capital recovery factor	[ ]	0.102	0.102	0.102	0.102	0.102	0.102	0.102	0.102
[10]	Annualized capital cost	[$USm]	340.8	358.5	459.5	477.1	82.6	678.5	53.5	89.4
[11]	Fixed O&M	[$USm/year]	43.1	45.3	58.1	60.3	14.6	77.4	6.8	13.1
[12]	Total annual cost	[$USm]	383.9	403.8	517.6	537.4	97.2	755.8	60.3	102.5
[13]	LCOE	[USc/kWh]	9.1	11.0	12.2	14.6	20.6	6.8	5.9	5.4

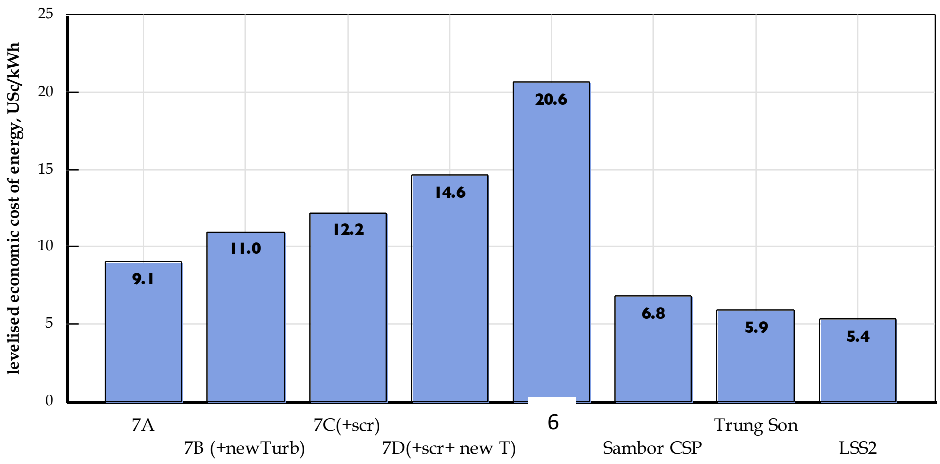

Figure 11-3. Levelised economic cost of energy, USc/kWh – before environmental damage costs.

Economic Benefits

Power Benefits

The main benefit of a single-purpose hydro project, namely one with no (or only very minor) flood control, irrigation or navigation benefits - is electricity production. How this benefit is valued depends on the perspective of the analysis. In a financial analysis conducted by the developer (whether IPP, PPP or Government owned), the financial benefit is straightforward: it is the net energy production at the metering point times the tariff as defined in the PPA.[90] However, the *economic* benefit of Sambor is unrelated to the PPA tariff. Rather, the economic benefit is the avoided cost of the next best alternative. So if, for example, the Sambor hydro power displaces gas-fired generation in Vietnam, the economic benefit is the avoided cost of gas (at the relevant border price) and the avoided cost of gas-fired capacity. The difference between the avoided cost, and the production cost of Sambor hydro power (including the cost of any transmission lines to enable export), constitutes the *net economic benefit*, which will be shared by the developer of Sambor, the Government of Cambodia, and either the foreign buyer (in the case of an export project) or the Cambodian consumer (if the off-taker is EdC). The tariff that appears in the PPA simply reflects the outcome of the negotiations between these three parties, and is not directly relevant to the *economic* analysis.

Obviously, for the economic benefits to be realized, the project must be financially feasible: a developer will not appear unless he can capture a sufficient portion of the net economic benefit to compensate investors for their capital investment, at a required rate of return on equity that, ultimately, only the investors can determine on the basis of their perception of project risk.

The Counterfactual for Economic Analysis

Given that the main economic benefit of the Sambor hydro project is the avoided cost of the next best alternative for generating dispatchable non-base load power, the following alternatives are possible:

90 Other potential sources of financial revenue such as that derived from the sale of carbon credits, or ancillary services, can be ignored here. In the foreseeable future, these are unlikely to be realized by the Sambor project, and prospects for such revenue will have no weight in the assessment of cash flows by lenders or investors. The project will stand or fall on the basis of the tariff revenues in the PPA.

- Coal or nuclear plus pumped storage – certainly one of the alternatives under consideration by EVN for Vietnam.
- Other hydro projects. Both Thailand and Vietnam have exhausted their own large hydro potential, and additional large hydro projects in the region will necessarily be in Cambodia or Laos.
- Gas-fired combined cycle projects – the most plausible thermal counter-factual for peaking and intermediate load power in all of the countries in the region.

The counter-factual is to some extent determined by the seasonality of hydro production. During the dry season, Sambor (of whatever alternative) would be operated as a daily peaking project, with generation limited to the peak hours of the day. During this time, the displaced generation will almost certainly be gas-fired generation that serves peak and intermediate loads.

Operation as a daily peaking project is illustrated in Table 11-9. Whatever the details of the operating policy, one would always attempt to have the reservoir level as high as possible so as to maximize the head and hence the energy output. In column [1] we show the average monthly flows, and in column [2] the average daily input (in million m^3. If all 12 turbines run at maximum discharge (1000 cumecs), the maximum daily volume would be 43.2 million m^3. Then in column [4] is shown the number of hours per day the turbines could generate at full capacity.

But such operation is possible only if there is enough storage to store the water during non-peak hours to allow discharge during the peak hours. Therefore, there needs to be enough storage to allow this. In fact, between the FRL (full reservoir level) (at elevation 39 masl (i.e. operation at maximum head) and 1 meter below (at elevation 38 masl) there is 114 million m^3 of storage, and the total active storage (between FRL and the minimum elevation to permit safe operation of the turbines) is 589 million m^3. It follows that there is enough storage to permit daily peaking operation in the dry months (column [5]).

Table 11-9. Operation as a daily peaking project.

	average monthly flow (1)	Average daily inflow	max turbine discharge per day (2)	Daily hours at maximum discharge	Required active Storage (approximately)
units	Million m^3	Million m^3	Million m^3	Hours	Million m3
	[1]	[2]	[3]	[4]	[5]
Jan	9,612	310	43.2	7.2	217
Feb	6,458	231	43.2	5.3	179
March	5,726	185	43.2	4.3	152
April	5,416	181	43.2	4.2	149
May	9,273	299	43.2	6.9	213
June	27,692	923	43.2	21.4	101
July	57,692	1,861	43.2	24.0	0
Aug	96,199	3,103	43.2	24.0	0
Sept	95,796	3,193	43.2	24.0	0
Oct	58,234	1,879	43.2	24.0	0
Nov	27,156	905	43.2	21.0	115
Dec	14,995	484	43.2	11.2	258

Notes
(1) average 1960-2005 at Stung Treng
(2) based on a design discharge of 1000 cumecs at each of the 12 turbines

However, during the wet months, when the reservoir is in spill condition, Sambor may be running 24 hours/day, in effect running as a base load plant. During such times one could hypothesize that coal units could be shut down.[91] This would have two consequences for the economic analysis. First, since the variable cost of coal that would be avoided is much lower than that of gas, the economic benefit of hydro would be lower. Second, avoided GHG emissions would increase, since the emissions per unit of coal generation are typically twice that of gas CCGT, which means that the economics of avoided GHG emission benefits will be higher. The extent to which these would offset the lower avoided fuel benefit would depend on the value of avoided carbon.

A full dispatch simulation of the EVN and EdC systems with and without Sambor is outside the scope of this report. However, all of the dispatch simulations for the EVN system 10 and 20 years into the future (conducted as part of the Power Development Plans prepared every 5 years),[92] that we have sighted, show the same result: even in summer when Vietnam's own hydro projects (mainly in the north) are at maximum output, gas CCGT generation in the south is dispatched 24 hours a day.

Vietnam's 500 kV North-south transmission axis is highly constrained, so in the short term the ability for Sambor hydro power to displace coal generation (that is presently mainly in the North) is limited. In the longer term, Vietnam plans imported coal projects in the south, but these will be supercritical projects totally unsuited for load following. Similar logic applies to exports to Thailand, or for the domestic EdC market.

The CCGT Counter-Factual

In short, we assess the *economic* benefits of Sambor as the avoided cost of combined cycle gas-fired generation, postulated as an LNG project on the coast. Such projects are indeed envisaged as part of the RGC capacity expansion plan. The cost of gas should be assessed at the border price of LNG (cost, insurance, freight). To this must be added costs of unloading and regasification, and the necessary maritime and terminal structures.

However, a first difficulty is that the future cost of LNG is subject to wide uncertainty. As shown in Figure 11-4, LNG prices over the past few years have been highly volatile, and in the years after the Fukushima nuclear plant shut-down in Japan, prices were in excess of US$15/mmBTU. But with the general price collapse of internationally traded fossil fuels in 2014-2015, LNG prices also fell sharply.

91 Routine scheduled maintenance should certainly done at this time.

92 See e.g., revised PDP VII.

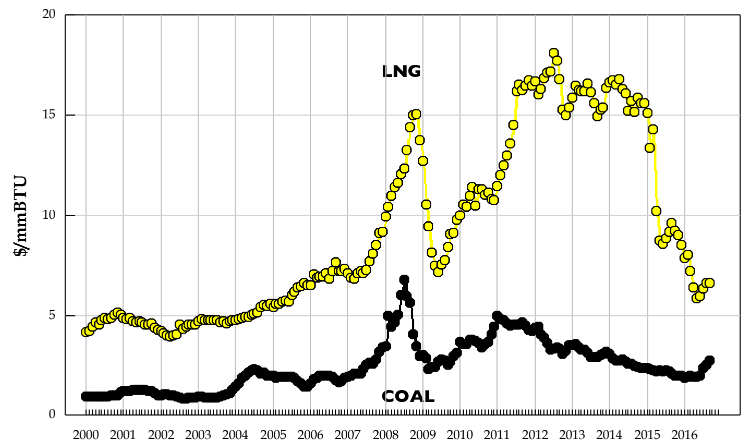

Figure 11-4. Annual average Asia-Pacific LNG and coal prices, $/mmBTU.

Given the dramatic changes in market prices over the past few years, it should not surprise that the most recent medium term price forecasts have also fallen dramatically. The late 2016 World Bank forecast for the 2025 LNG price – when hydropower from Sambor might become available - is US$8.84/mmBTU, reaching $10.00/mmBTU by 2030 (Figure 11-5).

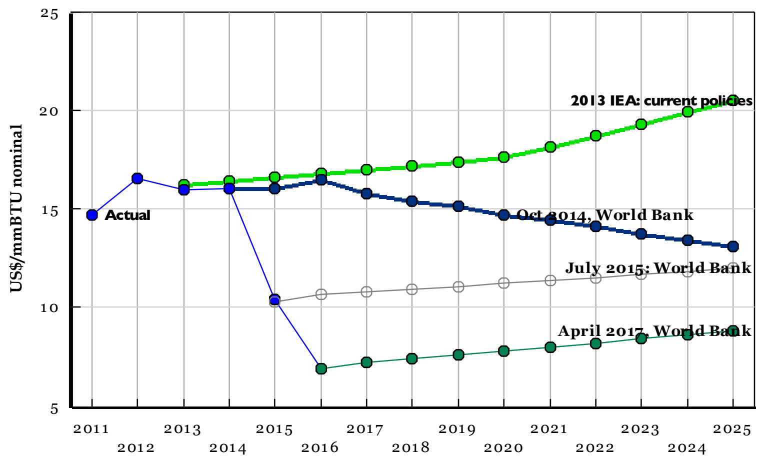

Figure 11-5. Forecasts for the Asia Pacific LNG price (cif Japan).

The prospects for future LNG prices are difficult to predict, notwithstanding that significant new liquefaction capacity is expected from Australia and the U.S. in the next few years. But if indeed there is a global shift away from coal in consequence of climate change concerns, demand for LNG may grow, taking up the new LNG supplies, and prices will increase. There is further uncertainty about the extent of delinking of LNG from crude oil prices and the expected growth in the importance of the LNG spot market.

In any event, predictions about future fossil prices are notoriously hazardous, so the baseline assumption we make here of $10/mmBTU by 2030 will be subject to one of the main uncertainties in the risk assessment – the plausible range of uncertainty even for a long-term average over the assumed economic life is high, ranging from a low of $5/mmBTU to a high of $15/mmBTU. To this must be added the costs of unloading and regasification which will add 0.75 – 1.5 USc/mmBTU, depending on the type of terminal.[93]

Table 11-10 shows the assumptions for up-front LNG infrastructure investment taken from recent studies. The assumption for our counter-factual is taken as $170 million (from the Sri Lanka study). FSRUs can be leased for typically 5 – 10 year periods on a day rate basis: the most widely used arrangement is in the form of a tolling fee per mmBTU, which we assume here at US$1/mmBTU (based on a recent contract in Pakistan).

Table 11-10. LNG infrastructure cost comparison, $USmillion.

	Sri Lanka	Tunisia
Land-based terminal	480	550
Marine structures for FSRU	170	150

Source: World Bank.

Table 11-11 shows the resulting calculation of the fixed costs of LNG-based CCGT generation, with a resulting cost of 3.66 USc/kWh. The costs are scaled to an annual production of 4,240 GWh (the energy generation of the Sambor Alt_7-A design) corresponding to an annual load factor of 0.57 which is typical for CCGTs operating as intermediate and peaking units.

Table 11-11. Fixed costs of LNG generation.

		Unit	
[1]	Installed capacity	[MW]	850
[2]	Capital cost	[$/kW]	1,045
[3]	Construction period	[years]	3
[4]	IDC adjustment	[ ]	0.103
[5]	Adjusted capital cost	[$USm]	980
[6]	FSRU marine structure	[$USm]	170
[7]	Transmission	[$USm]	180
[8]	Total capital cost	[$USm]	1,330
[9]	Life	[years]	20
[10]	Discount rate	[ ]	0.1
[11]	CRF	[ ]	0.12
[12]	Annual cost	[$USm]	156.2
[13]	Fixed O&M	[$/kW/month]	0.381
[14]		[$USm]	3.89
[15]	Total annual cost	[$USm]	160.1
[16]	LF	[ ]	0.57
[17]	Annual energy	[GWh]	4,240
[18]	Fixed costs	[USc/kWh]	3.78

Notes:
Row [2]: Based on overnight cost of $950/kW at ISO conditions. Under 30^{o} C ambient operating conditions in Southeast Asia, on a net basis this will be 10% more, so $1,045/kW. This is consistent with actual bid costs for CCGT in Vietnam and Singapore.

93 Two marine LNG terminal options for unloading and regasification can be considered: Land-based terminal, and a so-called Floating Storage and Regasification Unit (FSRU). FSRUs have become increasingly popular for smaller countries because they minimize up-front capital costs of land-based terminals, needing only a modest marine jetty.

The corresponding levelised cost is shown in Table 11-12: when adjusted for transportation differential and the FSRU tolling fee, the delivered cost to a coastal CCGT is US$10.5/mmBTU, and the levelised cost of energy computes to 11.7 USc/kWh.

Table 11-12. Total generation cost of LNG CCGT (at $10/mmBTU).

	Unit	Cost	Source
LNG cif Japan	$/mmBTU	10.0	World Bank, October 2016 Commodity price forecast
Less transportation differential	$/mmBTU	-0.5	
FSRU tolling fee	$/mmBTU	1.0	As reported for the Pakistan FSRU
Delivered to coastal CCGT	$/mmBTU	10.5	
Heat rate, net HHV	[ ]	0.48	Typical net HHV heat rate for CCGT operating at 30 C
	[BTU/kWh]	7,108	
Variable fuel cost	[USc/kWh]	7.46	
Non-fuel variable cost	[USc/kWh]	0.50	California Energy Commission (2014)
Total variable cost	[USc/kWh]	7.96	
Fixed costs	[USc/kWh]	3.78	(from Table 11-7)
Total cost	[USc/kWh]	11.74	

However, with the latest World bank LNG forecast still showing prices in the short to medium term of considerably less than $10/mmBTU, the benefit of the avoided cost of thermal energy in the short term is much lower. As will be seen in the economic analysis below, the levelised benefit of avoided energy is around 5.6 USc/kWh (rather than the 7.96 USc/kWh shown in the above table. Our baseline calculation of economic benefits is thus conservative.

Externalities

The World Bank's 1998 *Handbook on Economic Analysis* defines externalities as

> *The difference between the benefits (costs) that accrue to society and the benefits (costs) that accrue to the project entity.*

A rigorous definition of externality in the economics literature is more nuanced, requiring not merely that a third party is affected, but also that these impacts are not conveyed through market price signals.[94]

The choice of discount rate is particularly important in the valuation of externalities, because many (notably GHG emissions and their potential impacts on climate change) impose costs quite far in the future, and therefore how society balances costs and benefits today as against those in the distant future plays an important role in investment decisions. Not surprisingly, the subject is controversial: Appendix 10 outlines the main approaches advocated for its determination, and how discount rates have played an important role in past studies of damage costs of hydro projects on the LMB. The main points can be summarized as follows:

- The dominant externality of hydro projects on the Mekong mainstream is the impact on capture fisheries. At whatever discount rate, downstream capture fishery impacts dominate.

[94] The classic distinction is given by the example of a labor-intensive factory using coal for power, setting up next to a laundry (Baumol and Oates, 1988.). Soot that is deposited on the laundry's clean washing imposes incremental costs on the laundry, and constitutes an externality. But if the price of unskilled labor in the project region increases because the factory offers higher wages, the impact of higher labor costs on the laundry is *not* an externality, because it is conveyed by a market price signal.

- The downstream impacts of sediment capture are the second most important externality to be considered in the LMB because of its importance to the Mekong delta.[95]
- There are a range of other externalities, but these very much smaller than the fishery and sedimentation damages, and these remaining positive and negative impacts largely offset each other (see Appendix 11, Table 11.1.2).[96]
- The presentations of externalities in the *Costanza* and *Revised Costanza* reports omit the largest *positive* externality of hydro projects, namely avoided GHG emissions associated with the thermal generation that is replaced (albeit offset by GHG emissions associated with biochemical processes in the reservoir).
- Discount rate assumptions are critical. Results can be manipulated to produce very high damage costs by use of arbitrarily low discount rates for selected externalities. Consequently, the Costanza studies are unreliable guides for decision-making because of arbitrary choices about the application of different discount rates for different externalities.
- Indeed, the logic of using different discount rates for different costs and benefits is not clear. Why should the relative value of future consumption of fish relative to present consumption of fish be any different to the relative consumption of other goods and services consumed by households? Now there may well be issues of existence value to preserving the natural ecosystem, or issues of equity (livelihoods of poor fishermen versus better off urban residents who could more easily afford alternative sources of protein) – but these are attributes quite separate from economic efficiency, and should be *separately* traded off by decision-makers.
- In any event, it is Governments who should make such choices: Economists and Consultants (and foreign consultants in particular) have no special expertise in making that trade-off or to select the discount rate: the role of a consultant can only be to show the decision-maker what are the impacts of alternative discount rates. Just because some wealthy countries have set low discount rates to reflect their particular policy priorities should does not imply that all should use similar discount rates.

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95 It is worth noting that passing sediment is *not always* a benefit: there some examples where the objective of sediment management at a new hydro project is precisely the *opposite*, namely to *trap* sediment (to fill at least the inactive storage volume) to the *benefit* of an existing downstream project. The development of the Indus river cascade in Pakistan illustrates this point well: the operation of the existing Tarbela project is becoming compromised by the accumulation of reservoir sediment, which will have unacceptable impacts on the project's irrigation benefits (and to national food supply). The major new hydro projects that lie above Tarbela – the 4,800MW Dasu project and the 2,500 MW Basha project - demand a sophisticated sediment management strategy that trades off the cost of lower power generation at Dasu with the benefits of life extension of the downstream Tarbela project.

96 In the case of the MRC BDP2 scenario, positive externalities include irrigated agriculture ($1.6 billion) (figures here as lifetime PV); reservoir fisheries ($0.21 billion), and recession rice ($0.27 billion). Negative externalities include biodiversity loss ($0.4 billion), forest area reduction ($0.4 billion), Flood mitigation (0.3 billion).

The largest (and most controversial) positive externality in BDP2 is aquaculture ($1.2 billion), considered by most reviews to be grossly overstated. As noted by the MMCSEA, the replacement of capture fisheries loss by aquaculture production in the BDP2 is not realistic for two main reasons. Firstly, a large proportion of aquaculture production depends on capture fisheries for feed. Secondly, producing aquaculture is more costly than capturing wild fish. The *Revised Costanza* report reduces the value of aquaculture to $0.7billion.

- A sensible approach is to begin the benefit-cost analysis with a 10% discount rate (which in fact is consistent with the most recent World Bank policy grounded in welfare economics), and then ask how the investment decision might change under alternative values.

Sediment Passage

The Sambor Alt_7 options are expressly designed for passage of sediment through the engineering design of the structures and the anticipated sediment management regime based on regular flushing. By contrast, the CSP design will capture most of the sediment, mainly because the shape and large volume of the reservoir makes conventional flushing practice ineffective (see Chapter 4).

Sediment passage is important for three main reasons:

- The impact on rice production in Vietnam's Mekong delta (sediment provides a significant fraction of the fertilizer requirement that would otherwise need to be provided by purchased fertilizer.
- The role of sediment deposition in the delta to compensate for sea level rise and deltaic settlement.
- The impact of nutrients on coastal fisheries.

Impact of Sediment Production on the Mekong Delta

Rice production in the Mekong Delta area is of existential importance to Vietnam. Over the past five years, the Mekong Delta share of total national paddy production has increased slightly from 54 % to 56.7 % (Table 11-13).

Table 11-13. Production of paddy in Vietnam.

		2010	2012	2013	2014	2015
Vietnam total	1000 tons	40,006	43,738	44,039	44,975	45,215
Mekong River delta	1000 tons	21,595	24,320	25,021	25,244	25,699
as % of total	%	54.0%	55.6%	56.8%	56.1%	56.8%

Source: 2015 Statistical Yearbook of Vietnam, Table 172

The region also accounts for some 90% of Vietnam's rice exports. In 2014, rice exports were 6.3 million tons with a value of US$2.9 billion dollars (so an export price that averages $0.46/kg).[97] This implies that the balance of 18 million tons produced in the Mekong delta was consumed in the delta region, and is central to Vietnam's food security.

Figure 11-6 shows rice export prices as recorded by the World Bank Commodity price database.[98] Since the sharp price increase of 2008 attributable to a global rice and food security scare, rice export prices have fallen to a more stable level of around US$400/ton.

97 General Statistics Office of Vietnam, *Exports of Main Goods 2014.* Important as this may be, it is worth noting that the largest single category of exports is computers, electrical products and telephones ($34 billion), apparel and clothing ($20 billion) and footwear ($10.3 billion). 2015 Fishery product exports accounted for $7.8 billion.

98 The definitions in this chart are as follows: (1) Rice (Thailand), 5% broken, white rice (WR), milled, indicative price based on weekly surveys of export transactions, government standard, fob. (2) Bangkok; Rice (Thailand), 25% broken, WR, milled indicative survey price, government standard, fob Bangkok; (3) Rice (Thailand), 100% broken, A.1 Super government standard, fob. Bangkok; (4) Rice (Vietnam), 5% broken, WR, milled, weekly indicative survey price, Minimum Export Price, fob. Hanoi.

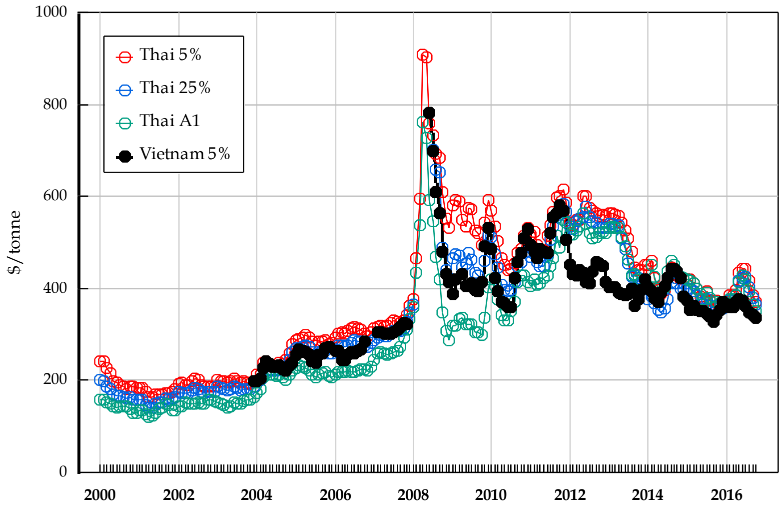

Figure 11-6. Rice export prices Source: World Bank Commodity Price Database (Pink Sheet).

Three seasons are generally suited to rice cultivation:

- Spring: late October to late April or May (cultivation during this season requires active irrigation);
- Autumn: late April to late September; and
- Winter: late May to mid-November.

Table 11-14 shows Mekong Delta paddy production in these three seasons: relatively few farms rely on a three-crop rotation. Of course, many other crops are also grown in the delta, but recent research highlights the dominant importance of rice.

Table 11-14. 2015 Mekong delta paddy production by season.

		spring	autumn	winter	Total
planted area of paddy	1000 ha	1,562	2,360	386	4,308
Production	1000 tons	11,131	12,732	1,836	25,699
Yield	kg/ha	7,126	5,395	4,756	5,965

Source: Statistical Yearbook of Vietnam, (2015) Tables 172-176.

Table 11-15 shows the importance of fertilizer costs to the total production cost of paddy, accounting for some 25% of the total – if 50% of the fertilizer input were provided by sediment, then its loss would double the fertilizer costs shown in this table. Fertilizer costs suffer periodic booms (as in 2008-2009), but since 2012 prices have gradually decreased (Figure 11-7).

Table 11-15. Fertilizer costs in paddy production.

	VND1000	%	VND1000	%
	Two-crop		Three-crop	
Cost of land preparation	479.74	3.04	1020.83	6.39
Cost of seed	1022.18	6.48	912.71	5.71
Cost of fertilizer	3889.49	24.66	4298.76	26.9
Cost of herbicide	379.47	2.41	401.2	2.51
Cost of pesticide	2994.43	18.98	2699.32	16.89
Cost of land lending	948.79	6.02	849.49	5.32
Cost of depreciation	124.05	0.79	117.91	0.74
Cost of loans	205.73	1.3	186.35	1.17
Cost of harvesting machine	1301.19	8.25	1023.88	6.41
Cost of irrigation	926.54	5.87	822.63	5.15
Cost of labor	2793.94	17.71	3025.45	18.93
Cost of other	707.85	4.49	623.34	3.9
Total	15773.4	100	15981.79	100

Source: Chapman *et al* (2015).

Manh and Dung (2014) find that depending on the flood magnitude, annual sediment loads reaching the coast vary from 48 to 60% of the sediment load at Kratie. Deposited sediment varies from 19 to 23% of the annual load at Kratie in Cambodian floodplains, and from 1 to 6% in the compartmented and diked floodplains in Vietnam. Annual deposited nutrients that are associated with the sediment deposition provide on average more than 50% of mineral fertilizers typically applied for rice crops in non-flooded ring dike floodplains in Vietnam.

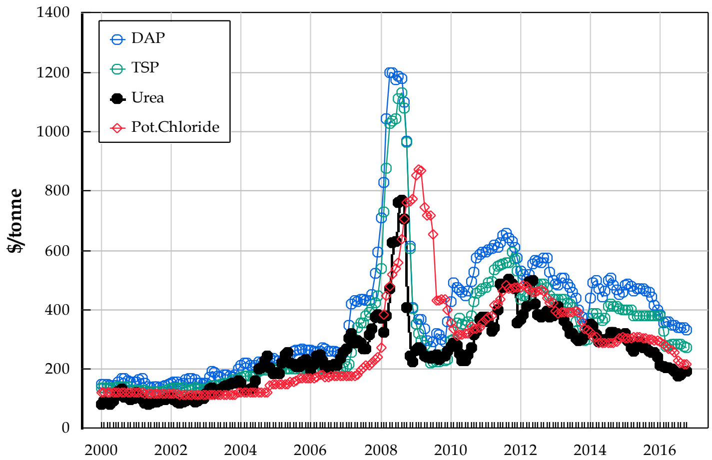

Figure 11-7. International fertilizer cost benchmarks.

Valuation of Damage Costs

Valuation of the various damage costs associated with the capture of sediments at Sambor is difficult, and there are few empirical studies of the contribution of sediments to the fertilizer budgets of rice farmers in the delta: the analysis is complicated by different cropping patterns and farming practices. Chapman *et al*, (2016) conducted field studies in An Giang province (which adjoins Cambodia, and is the most upstream of the Vietnamese provinces in the Mekong delta). On the basis of econometric modeling, they conclude that if all paddies were operating the double cropping system and receiving the average deposition depth of 2.5 cm/year, the 2015 value of sediment-bound deposited nutrients to An Giang paddy rice farmers was US$26 million (with a range of ±$9million). An Giang province accounts for about 15% of the total paddy area in the

Mekong River Delta, and 17% of the total paddy production, so the potential value for the Delta as a whole would be about US$160 million per year. However, sediment loads have already fallen over the past few years, so the incremental impact on rice production in the delta attributable to sediments that would be subject to capture at Sambor is assumed at $120 million per year.[99]

Fishery Damage Costs

The importance of capture fisheries in Cambodia, downstream of the Sambor dam site, is widely recognized. While the proportion of GDP accounted by fishery in Cambodia is gradually declining as the development of a more broadly based modern economy proceeds, MRC estimates that it still accounts for some 18% of GDP (So Nam, 2015). More importantly, it accounts for the livelihood of millions of relatively poor people and the major source of the protein intake of the Cambodian rural population. Any major disruption of the capture fisheries by the Sambor project would therefore have serious economic consequences for Cambodia.

The importance of fishery to the Vietnam economy is somewhat less. The Mekong River Delta is the most important area in Vietnam for fisheries, and indeed between 2000 and 2008 its share of the total national fisheries output increased from 60% to 68% (Table 11-16). However, the share of fisheries as a share of total national GDP appears to have peaked in 2008 with a 10.2% share, falling to 7.0% share by 2012. The most recent estimate of the value of the Mekong fishery is just 3.1% of GDP (So Nam, 2015), see Table 11-16.

Table 11-16. Vietnam Mekong River Delta Fisheries.

		2000	2008	2012	2014
Price level		1994	1994	2010	
All Fisheries	VND billion	21,777	50,082	168,036	
Mekong River delta	VND billion	13,139	33,891		
Mekong River delta share		60%	68%		
Total GDP	VND trillion	274	489	2,413	
All fisheries GDP share		8.0%	10.2%	7.0%	
Mekong River delta GDP share		4.8%	6.9%		3.1%

Source: Statistical Yearbook of Vietnam, 2008 and 2012. Vietnam estimate for 2014 from So Nam (2015).

The Affected Fish Population

We begin with an estimate of the size of the Mekong basin fish catch in Cambodia and Vietnam. Depending on definitions, these estimates are in the range of 1.2 – 2.7 million tons per year (mtpy) (Table 11-17).

Table 11-17. Mekong Basin fish catch (tons/year).

	Cambodia	Vietnam	Total	Source
Capture fishery and OAAs	558,000	719,000	1,277,000	MRC (2010)
Total catch	682,150	844,850	1,527,000	Van Zalinge et al., 2004
Total catch	588,000	719,000	1,307,000	Nam(2015)
Total fish plus OAAs	586,000	851780	1,437,780	Halls(2010)
Total fish catch			2,600,00	Cowx et al (2015)
Capture fish +OAA			1,300,000-2,700,00	Hortle and Bamrungrach (2015)

[99] This is somewhat lower than the $220 million estimate in the Mekong Delta Study (MDS) which estimates a loss of rice production in Vietnam of 550,000 tons/year at $400/ton. However, such an approach assumes that rice farmers would produce less rice, rather than make up the loss of nutrients with purchased fertilizer.

The results of the most recent 2015 report by the MBC on the question of total fish yields is shown in Table 11-18 (Hortle and Bamrungrach, 2015). Column 7 has been added by us and represents the fish yields likely to be influenced by any Sambor dam – the sum of fish yield of Cambodia and the Vietnam data, namely 1.117 million tons. Whether this estimate, which is lower than all of the estimates in Table 11-18, is a reflection of the long-term decline in the sustainability of the fishery is unclear.

Table 11-18. Fish yields in the LMB (mtpy).

	Cambodia	Lao PDR	Thailand	Vietnam		Total LMB	Total Sambor
				Delta	Highlands		
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Major flood zone	565	92	117	260	0	1034	825
Rained	176	90	698	64	16	1044	240
Other large water bodies	26	64	106	25	5	226	51
Total yield	767	246	921	349	21	2304	1116
Consumption (2000)	558	166	861	659	60	2304	1407
Surplus/deficit	209	80	60	-310	-39	0	-291

Source: Hortle and Bamrungrach (2015).

Significant variations in annual catch are common, as shown in Figure 11-8 for Tonle Sap. This also shows the strong correlation with water levels, another variable that may be affected by the regulation of the many dams upstream.

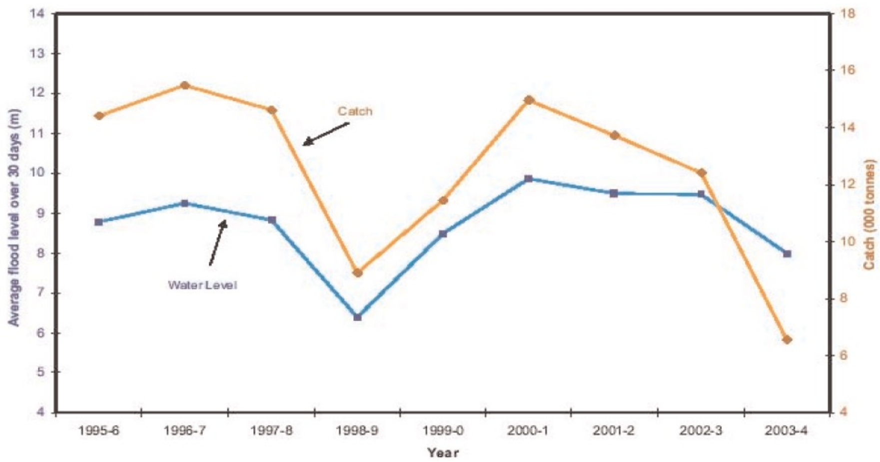

Figure 11-8. Variation in fish catch, Tonle Sap. Source: Mekong River Commission, 2004.

The extent to which the existing fishery is in long term decline due to over-fishing – even before the construction of mainstream dams – remains unclear. For the baseline calculation (i.e., in the absence of Sambor) we assume a constant sustainable yield of 1.2 mtpy.

In any event, the *entire* fishery is *not* at risk. First, not all fish are migratory in the Mekong mainstream. Second, of those that are migratory, not all spawn above Sambor. The value of both of these adjustments is highly uncertain. The MRC has estimated that some 38 % of the total fish are migratory; for the faction that spawn above Sambor there are no reliable data at all, but MRC: Sambor has estimated a plausible baseline value of 70 % (i.e. 30 % have spawning areas *below* Sambor). Both of these baseline assumptions therefore play a key role in the risk assessment of Chapter 12.

Modelled Fishery Values Used for the Economic Analysis

Modelling requires assumptions to be made. The modelling results of impacts on the fishery (Maximum Sustainable Yield or MSY), as described in Chapter 8, are a result of numerous assumptions about fish life cycles and impacts at the dam.

The difference in modelled impacts on the fishery (MSY) is dependent on a critical assumption of fish mortality at the trash racks of the turbine intakes. If the assumption is low mortality, then the fish screens provide little benefit in the modelled results compared to the trash racks (i.e. with no fish screens), but if the assumption is high mortality at the trash racks, the fish screens provide a far greater benefit.

Fish mortality on debris screens (or trash racks) is well known at cooling water intakes for power stations throughout the world (see Chapter 7 for review) and mortalities of fish at trash racks of hydropower intakes undoubtedly occur. However, we were unable to find quantitative data on the proportion of fish that would be affected, especially in large tropical rivers. For the present fish population modelling we assumed a low value of 10% of adult fish mortality on the trash racks, so the present modelling shows little difference in impacts on fish populations between trash racks or fish screens. If the assumed value was 90% mortality, which is a possibility, the fish screens would provide a far greater benefit and protection for the fishery; and the trash racks could cause a far greater decline in the fishery. As discussed in Chapter 8 we recommend that further modelling be done with higher values of mortality on the trash racks to assess their impact, and clarify the need for fish screens.

For the present report, the following economic analysis needs to be read in the context that the present values have, to some extent, underestimated the impacts of the trash racks on migrating fish, so the benefits of fish screens are not apparent; while the costs of the fish screens are also very preliminary.

Impact of the Dam on the Fishery

The impacts of the proposed Sambor dam are presented as a percentage decline of the mean sustainable yield (MSY): these take into account the physical configuration of the dam, spillway, and turbines, as well as the critical assumption of upstream fish pass efficiency. The detailed fish modeling results, to be reported in Chapter 8 of the final report, are still underway, but the interim baseline assumptions are as shown in Table 11-19.

Table 11-19. Baseline assumptions for fishery impact (as %age loss of MSY).

Upstream Passage Success	95%	80%	60%
Sambor Alt_7-A	19	45	81
Sambor Alt_7-B	8	23	45
Sambor Alt_7-C	10	37	72
Sambor Alt_7-D	6	21	42
Sambor Alt_6	19	45	81
Sambor CSP		Not achievable	

For the baseline calculations, we assume an average fish pass efficiency of 80% - which is significantly higher than past experience (20% for non-salmonid and 60% for salmonid species, Noonan *et al*. (2011)). This seemingly optimistic baseline assumption is however justified by the extensive and unique fish protection measures assessed by NHI, which have no precedent anywhere in the world. Nevertheless, uncertainty in these calculations is high, and is discussed further in the risk assessment of Chapter 11. The approach taken in that assessment is to ask what change in MSY would be required in order for the project to produce net economic benefits.

The NHI review of the CSP design concludes that its upstream fish passage facilities are very unlikely to achieve anything better than the global averages of about 40%, from which one may conclude a collapse of the fishery is to be expected.[100] Indeed, because of the low velocities in the very large CSP reservoir, very high mortality of riverine fish larvae that require drift, may be expected.

However, whether for the CSP or the Sambor alternatives, it may well be that some species adapt to a barrier at Sambor, and would find new spawning grounds. Unfortunately, the potential for adaptation can only be determined once the dam is built, at which point the impacts may be irreversible.[101]

Impact of Peaking Operations

Daily peaking operations (see Table 11-9) may cause large daily downstream water fluctuations. As noted by the MDS (2015), these flow modifications could have serious potential environmental impacts on the river between Sambor and potentially as far downstream as Phnom Penh. The regulated flows in this reach – notably during the dry season months - could result in losses in fish production, reduction in reproductive output and impede upstream migration of adult fishes. Large and rapid changes in water levels and velocity within deep pools would also reduce the quality of those important sites as dry season refugia for fish. In addition, the altered hydrology will be disruptive to migration of adult fishes, disrupting their behavioral migration cues and migration cycles. The large daily fluctuations would also make fishing more difficult, which would impact the livelihood of the people dependent upon fishing in this region.

This is not an uncommon problem at hydro projects, even where fishery damages are of lesser concern than at Mekong mainstream projects. To some extent this can be mitigated by imposing on the operation of the project constraints on the rate and extent of ramping up and ramping down, which may make it more difficult for the hydropower operations to follow the grid load curve.[102]

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[100] The adequacy of the fishway in the CSP FS can be gauged by its cost estimate for which some $9.7 million is provided. This compares to the cost estimates for fish-ways in the Sambor Alt_7-A alternatives of

Anabranch Fishpass	$	97,4 million
Right Bank Fishpass	$	102,3 million
Shiplock Fishpass	$	42,1 million
Total	$	241,9 million

More important is the energy penalty of proper operation of the fishway that is a consequence of needing to provide adequate flow: our estimate is that energy production at Sambor Alt_7-A could be some 2,400 GWh higher in the absence of the fish protection measures.

[101] For further discussion, see Halls (2016).

[102] As for example at the World Bank financed Trung Son project in Vietnam (World Bank, 2011). A very rapid increase from 63 cumecs (the minimum environmental flow) to the full turbine discharge of 503 cumecs was 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 meters at 503 cumecs. It was therefore decided to impose ramping rules such that the rate of change in downstream flow should not be greater than that which occurs without the project, estimated at 40cumecs/hour. This required a 11-12 hour period to increase from 63 to 503 cumecs.

This may be of little consequence to the IPP if the PPA has a single energy charge (as at LSS2) – indeed, since head losses are a function of discharge, more even distribution may increase total kWh generated. However, such constraints will reduce the economic value of the project to the off-taker (EdC or potential imported of Sambor power in Vietnam or Thailand).

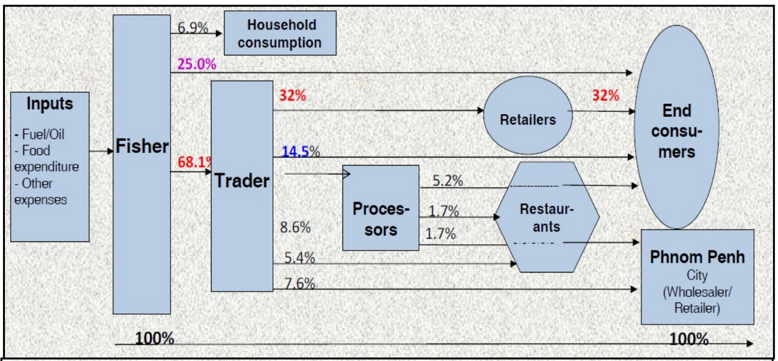
Valuation of potential damage costs attributable to unmitigated daily peaking operation is not attempted in this report, but noted as an issue for the necessary environmental impact study if a Sambor project were to move to a full feasibility study.

Fish Valuations

As noted by the MBC Economics Practice Guide, the economist's definition of the value of the fishery resource benefit is the *net* value of the resource, calculated as the gross value minus the opportunity cost of the resources used to capture or produce the fish. In previous studies one sees a wide range of estimates:

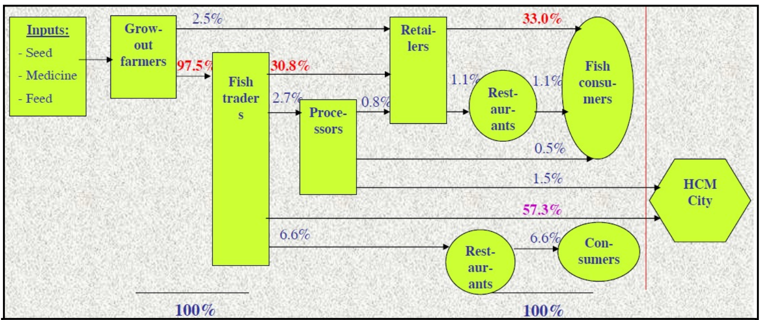
- The MMHSEA used US$1.40/kg but it is unclear how this was chosen.
- BDP2 used $3.00/kg as a "replacement cost" – but *Costanza* argues that this underestimates the true value of the resource since it takes no account of multiplier effects on local rural economies.
- *Revised Costanza* proposed US$2.50 for aquaculture and reservoir fish, and US$3.50 for capture fisheries (claimed to be "conservative compared to today's market prices"). The report notes that wild white fish prices are in the range of US$5-$10/kg.

These valuations should be scrutinized in light of what is known about the value chain. The value chain analysis for snakehead fish suggests a retail price of 2.93$/kg for capture fish (Figure 11-9), but only 2.4 $/kg for farmed fish (Figure 11-10): the fisherman's selling price for captured fish is US$1.62: of the total value added of US$2.09, slightly less than half is achieved by wholesalers and retailers. Use of retail market prices (as in the *Costanza* reports) is the *gross*, not the *net* economic value of the fishery, and will overstate the fishery damage costs.



Description	Fishers	Wholesalers	Retailers	Total
Selling price	1.62	2.11	2.93	
Buying costs	0.57	1.62	2.11	
Added costs	-	0.02	0.25	
Net added value	1.05	0.47	0.57	2.09
% of net added value/kg	*50.2*	*22.5*	*27.3*	*100.0*
Production/HH/year (ton)	1.41	96.36	5.70	
Total profit (USD/year)	1,480.5	45,289.2	3,249.0	50,018.7
% of NAV/actor/year	*3.0*	*90.5*	*6.5*	*100.0*

Figure 11-9. Snakehead capture fishery value chain analysis. Source: Sinh et al (2012).



Description	Farm-ers	Whole-salers	Proces-sors	Retailers	Total
Selling price (USD/kg)	1.65	1.77		2.4	
Buying cost (USD/kg)	1.4	1.65		1.77	
Added cost (USD/kg)	-	0.051		0.08	
Net added value (USD/kg)	0.251	0.069		0.554	0.874
% Net added value/kg	*28.8*	*7.8*		*63.4*	*100.0*
Output/actor/year (tons)	14.1	728.2		6.0	
Total profit/actor/yr (USD)	3,542.9	49,931.4		3,325.7	
% NAV/actor/year	*6.2*	*87.9*		*5.9*	*100.0*

Figure 11-10. Cultured snakehead fishery value chain analysis. Source: Sinh et al (2012).

In any event, the actual average value will depend on the weighted average values of the mix of species affected.[103] Table 11-20 shows the fish valuations used in the Mekong Delta Study – the bulk of damage costs are related to white fish, valued at US$1.60/kg.

[103] Such value differences between capture and cultured fish are observed worldwide (e.g. as in Scotland and Norway for salmon).

Table 11-20. Fish valuations in the Mekong delta study.

		White fish	grey fish	black fish	marine/ estuary fish	exotic fish	OAA	total
Fish price	VND/kg	35,105	35,105	18,084	35,105	35,105	18,084	
	US$/kg	1.60	1.60	0.82	1.60	1.60	0.82	
Total loss of fish	1000 tons/year	277	19.5	11.5	19.1	14.6	25	367
	$USm	442	31	9	30	23	21	557
Income	%	0.13	0.13	0.2	0.13	0.13	0.2	
Lost income to fishermen	$USm	57.5	4.0	1.9	4.0	3.0	4.1	74

Source: MDS (2015).

Given the wide range of uncertainty and methodology, the conservative baseline valuation used in this report is US$1.5/kg. As will be shown in the sensitivity analysis of Chapter 11, this is a critical assumption, and any average values above US$2.50/kg, together with upstream passage rates below 95% makes it almost impossible to achieve any net benefit from a mainstream project at Sambor.

It may be argued that just as we have valued the benefit of hydropower as the avoided cost of the next best alternative (thermal generation), so could one value fish at its next best alternative for providing the equivalent protein demand – which is cultured fish (i.e., aquaculture). But the market price of cultured fish is *lower* than that of capture fish, not higher (as in the case of power production). It may also be the case that as the impact of mainstream dams reduces the sustainable yield of the fishery, the market price for capture fish will increase. But depending on the price elasticity of demand for capture fish, the income to fishers may not decline (if the quantity halves and the price doubles, the income to fishers remains the same), though there will be some loss of consumer surplus.

Avoided GHG Emissions

As noted in its report to COP21, *Intended Nationally Determined Contribution* (INDC), Cambodia is a low emitter of greenhouse gases (GHG) and highly vulnerable to the negative impacts of climate change. The INDC states that the energy sector is to reduce 2030 CO_2 emissions by 16% (1,800 Gg, or 1.8 million tons), to be achieved mainly by grid-connected renewable energy (solar, hydro, biomass and biogas). It is therefore reasonable to include the avoided GHG emissions of a Sambor hydro project as a positive externality. In principle, concessionary and carbon finance should be available to Cambodia to assist the achievement of these targets, and in this section, we discuss GHG emissions as they would need to be presented were carbon finance to be sought from the World Bank. This requires not only a presentation of the *avoided* GHG emissions of the thermal counter-factual, but also an assessment of any *increased* GHG emissions from the hydro reservoir[104], and the use of the new World Bank guidelines for the social value of carbon (World Bank, 2014).

Given a thermal generation counter-factual, the avoidance of GHG emissions associated with this generation constitutes a positive externality of any Sambor hydro project, whose quantification

[104] However, as noted, the chance of concessionary IFI or carbon finance for a hydro project on an international waterway would require "no objection" from the downstream riparian, which for a dam that may well destroy a significant part of the LMB fishery, and blocks sediment flow to the Mekong delta in Vietnam, is most unlikely to be forthcoming.

appears in the *benefits* section of the Table of economic flows. The beneficiary is the global community.

Quantification

The minimum mandatory requirement under the World Bank's carbon accounting guidelines (World Bank, 2015) is the calculation of GHG emissions from combustion ("operational emissions within the project boundary"). An "optional" calculation is to also include upstream emissions associated with fuel supply and transport, and to report total "life-cycle emissions." Other authorities are unequivocal about the need to include life-cycle impacts: "*ignoring this will lead to wrong assessments and misperceptions about the environmental credentials of a fuel, a technology or a product*" (Australian Academy of Technological Sciences and Engineering, 2009).

GHG emissions from combustion are readily calculated as a function of the assumed efficiencies and the default emissions data from the Intergovernmental Panel on Climate Change (IPCC). Table 11-21 shows the calculation for CCGT.

The life cycle emissions of gas CCGT will depend on whether domestic gas or LNG is used. Upstream emissions associated with LNG liquefaction, transportation (over often very long distances) and regasification together increase total GHG emissions by as much as 20%. For example, a Japanese study estimates combustion emissions of 407 gm/kWh, and LNG fuel cycle emissions adding another 111 gm/kWh (Hondo, 2005).

Table 11-21. GHG emissions from CCGT.

[1]	IPCC default emission factor	[Kg/MJ]	56.1
[2]	HHV efficiency net	[ ]	0.48
[3]	LHV efficiency net	[ ]	0.528
[4]	heat rate	[MJ/kWh]	6818
[5]	net emissions	[kg/kWh]	0.3825
[6]	life cycle emissions adjustment	[ ]	1.3
[7]	net emission factor	[kg/kWh]	0.497

The most comprehensive study in the literature of life-cycle emissions in the LNG value chain is that by Heede (2006) for the Cabrillo deepwater port that was part of a proposal for an LNG project in California (importing LNG from Australia).[105]

This study showed that consideration of the LNG supply chain adds some 38% to the GHG combustion emissions of both CO_2 and methane.[106]

For the calculations presented in this report, and for sake of conservative calculation we adjust LNG combustion emissions by 30% (so somewhat less than trans-pacific transport), hence 497g CO_2 eq./kWh.[107]

[105] The study predates the fracking revolution: today, the US is seen as an *exporter* of LNG, not an *importer*. However, the conclusions of the study regarding GHG emissions associated with long distance LNG transport remain valid.

[106] For combustion emissions of 16.5 million tons, there are supply chain emissions of 6.3 million tons, so for every kg of GHG emissions in combustion, there is an additional 6.3/16.5=0.38Kg from the supply chain.

Monetization

The relevant metric (for economic analysis) is the global social damage cost, expressed as $/ton CO_2. Needless to say, such valuation is controversial, and whose estimates vary from institution to institution. Table 11-22 shows the social value of carbon (SVC) as used by the World Bank for its project appraisals. In the event that the Sambor project were to be financed by the World Bank, or its financing to be benefit from a partial risk guarantee (PRG), use of these values are now mandatory, and the net economic benefits of the project would need to be calculated with and without consideration of the SVC.

Table 11-22. Social Value of Carbon (SVC), $/ton CO2 (in constant 2014$).

	2015	2020	2030	2040	2050
Low	15	20	30	40	50
Base	30	35	50	65	80
High	50	60	90	120	150

Source: World Bank (2014)

The valuations proposed by the US Government are shown in Table 11-23. These are expressly specified as a function of the discount rate, and as in the case of the World Bank, they increase over time.

Table 11-23. GHG valuation and discount rate, $/ton CO2 (in 2007 US$).

Discount rate>	5%	3%	2.5%
2015	5.7	23.8	38.4
2020	6.8	26.3	41.7
2025	8.2	29.6	45.9
2030	9.7	32.8	50.0

Source: Interagency Working Group on Social Cost of Carbon (2010).

GHG Emissions of Hydro Projects

The avoided GHG emissions associated with the gas-CCGT counter-factual will be offset by the GHG emissions of the hydro project, namely those that derive from biochemical processes in the reservoir. The extent of GHG emissions will depend on the nature of the biomass that is to be flooded, and the extent to which vegetation is cleared before inundation. In large and shallow reservoirs of the type exemplified by Sambor, total vegetation clearance is an expensive item, and often only limited clearance is the actual result.[108]

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. The United Nations Framework Convention on Climate Change (UNFCCC) issued a draft guideline for the CDM eligibility of hydro projects based on this indicator (UNFCCC, 2010): these define three categories of projects:

- 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;

[107] To the extent that during the wet season, Sambor were to displace coal, avoided emissions would be considerably higher – subcritical coal projects typically have emissions of 900 g CO_2/kWh.

[108] The cost breakdown in the CSP FS gives a clue for what is envisaged by Sambor's CSP designers – only some $6.4 million for "reservoir clearance" hardly suggests comprehensive vegetation clearance for an area of 620 km^2.

- 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.

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

As shown in Table 11-24, even the Sambor CSP project falls into the “satisfactory” category, with a default emission penalty of 90 g/CO_2eq/kWh. Most of the other projects in Laos and Cambodia have much lower power densities (as one would expect for the lower reaches of large rivers where hydraulic heads are small and reservoirs large and shallow). The Sambor Alt_7-A project has a very high power density of 18.36 W/m^2, the highest in the LMB (for which we have data).

Table 11-24. Power densities, Mekong Basin hydro projects.

		Km^2	MW	W/m^2	
Sambor Alt_7-A	Cambodia	67	1230	18.36	
Ban Kum	Laos	142	1872	13.18	Good
Hoa Binh	Vietnam	208	1920	9.23	Satisfactory
Son La	Vietnam	440	2400	5.45	
Nam Ngum 2	Laos	118	615	5.21	
Sambor China Southern FS	**Cambodia**	**620**	**2600**	**4.19**	
Nam Theun 2	Laos	367	1075	2.93	Unsatisfactory
Sirikit	Thailand	259	500	1.93	
Srinagarind	Thailand	419	720	1.72	
Xekong 4	Laos	175	300	1.71	
Xekaman 1	Laos	157	226	1.44	
Nam Pha	Laos	103	147.2	1.43	
Rajjaprabha	Thailand	185	240	1.30	
Lower Se San2	**Cambodia**	**335**	**400**	**1.19**	
Nam Mouan	Laos	115	110	0.96	
Xe Xou	Laos	122	63.4	0.52	
Theun-Hinboun exp	Laos	119	60	0.50	
Nam Nga	Laos	202	97.8	0.48	
Nam San 2	Laos	141	60	0.43	
Nam Ngum 1	Laos	369	148.7	0.40	
Nam Hinboun 1	Laos	164	45	0.27	
Lower Sre Pok 4	Cambodia	581	143	0.25	
Lower Sre Pok 3	Cambodia	880	204	0.23	
Lower Se San 3	Cambodia	1084	243	0.22	
Sirindhorn	Thailand	257	36	0.14	
Ubol Ratana	Thailand	319	25	0.08	

Such detailed calculations are not available for Sambor, but a detailed GHG emissions assessment of the Nam Theun 2 (NT2) project in Laos suggests emissions of 78 g CO_2eq/kWh, slightly below the default value of 90 g CO_2/kWh (Table 11-25).

Table 11-25. GHG emissions from NT2. Source: Zhou, 2011.

	g CO_2eq/kWh
Construction	$2.5\underline{+}0.5$
Operation	$75\underline{+}5$
Decommissioning	$0.6\underline{+}0.05$
Total	$78.1\underline{+}5.55$

When life-cycle GHG emissions are applied consistently, the *net* impact on GHG emissions will still be significant. The avoided GHG emissions of gas CCGT are taken as 497g CO_2eq/kWh, the GHG emissions from Sambor are taken as 90 g CO_2eq/kWh, and those for Sambor Alt_7-A, scaled by reservoir area, at 11.2 g CO_2eq/kWh.

Baseline Calculations of Externality Damage Costs

Table 11-26 shows the baseline calculations for externality damage costs. Our review of the CSP Sambor design suggests that even a 40% upstream fish passage rate would be optimistic, to say nothing of close to 100% downstream mortality for larvae. As proposed in the CSP FS, one may expect a catastrophic impact on fisheries, with the loss of the entire migratory fishery that presently passes the Sambor site – though this does presuppose that fish migration is not already cut off immediately above Sambor at such projects as LSS2, Strung Treng and Xayaburi (in which case investment in a fish friendly design at Sambor would indeed have no point).

Table 11-26. Baseline calculations for externality damage costs (per year).

			Alt_7-A	Alt_7-B (7A+new turbines)	Alt_7-C (7A+ screens	Alt_7-D (7A+new turbines+ screens	Alt_6	CSP	LNG-CCGT
[1]	**Fishery**								
[2]	Fishery yield	tons/year	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000	
[3]	Migratory fraction	[ ]	0.38	0.38	0.38	0.38	0.38	0.38	
[4]	Total migratory biomass	tons/year	456,000	456,000	456,000	456,000	456,000	456,000	
[5]	Fraction spawning below Sambor	[ ]	0.30	0.30	0.3	0.3	0.3	0.3	
[6]	Potentially affected by Sambor dam	tons/year	319,200	319,200	319,200	319,200	319,200	319,200	
[7]	Fish passage achievement		0.80	0.80	0.80	0.80	0.80	0.40	
[8]	MSY loss [modelled]	[ ]	45.0%	23.0%	37.0%	21.0%	45.0%	100.0%	
[9]	Total MSY lost	tons/year	-143,640	-73,416	-118,104	-67,032	-143,640	-319,200	
[10]	Fish valuation	$/kg	1.50	1.50	1.50	1.50	1.50	1.50	
[11]	Value of lost fishery	$USm/year	-215	-110	-177	-101	-215	-479	
[12]		**USc/kWh**	***-5.08***	***-2.99***	***-4.18***	***-2.73***	***-45.7***	***-4.31***	
[13]	**Sediment loss to Mekong Delta**								
[14]	Sediment load at Sambor	[mtpy]	90	90	90	90	90	90	
[15]	Sediment capture fraction	[ ]	7.0%	7.0%	7.0%	7.0%	4.0%	62.0%	
[16]	Sediment loss	$USm	-8	-8	-8	-8	-5	-74	
[17]		**USc/kWh**	***-0.20***	***-0.23***	***-0.20***	***-0.23***	***-1.02***	***-0.67***	
[18]	**GHG emissions**								
[19]	Reservoir area	km2	67	67	67	67	0	620	
[20]	Power density	W/m2	18.4	15.7	18.4	15.7		4.2	
[21]	Emission factor	gCO_2/kWh	11.2	11.2	11.2	11.2	0.0	90.0	300
[22]	Emissions	mtons CO_2	0.047	0.040	0.047	0.040	0.000	0.999	1.272
[23]	Value per ton CO2 eq	[$/ton]	30	30	30	30	30	30	30
[24]	Damage cost	[$USm]	-1.4	-1.2	-1.4	-1.2	0.0	-30.0	-38.2
[25]		**USc/kWh**	***-0.03***	***-0.03***	***-0.03***	***-0.03***	***0.00***	***-0.27***	***-0.90***

Other Externalities

As discussed in more detail in Appendix 11.1, a range of externalities (other than on capture fishery and sediments) have been proposed for consideration (Table 11-27). However, with the exception of aquaculture and reservoir fisheries, these can safely be ignored: the most recent assessment by NREM (2017) shows that these account for just 2.5% of those for fishery and sediments.

The estimated benefits for reservoir fisheries are suspect. The BDP2 states the total increase (for all 11 mainstream dams) is 64,000 tons per year. NREM values these at $2.5/kg, for a total annual benefit of $US160 million: that which can be attributed to Sambor will be a small fraction of this. However, the arguments presented by NREM about the benefits of reservoir fisheries are valid (only nine Mekong fish species are known to breed in reservoirs, and unless there is complete clearing of biomass before inundation, poor water quality may adversely affect reservoir fish catch).[109]

Table 11-27. Other externalities (as NPV, 10% discount rate).

	BDP2	NREM
Fishery impacts	-1,936	-13,030
Sediment related impacts	0	-2,311
	-1,936	-15,341
Other		
Irrigated agriculture	1,659	1,832
Wetlands	101	238
Social/Cultural Impact	0	-1,665
Eco-hotspot/biodiversity	-415	-458
Forest area reduction	-372	-411
Recession rice	278	307
Flood mitigation	-273	-301
Salinity mitigation	-2	-2
Navigation	64	71
Total other	1,040	-389
Aquaculture	1,261	931
Reservoir fishery	215	822

Source: BDP2, NREM.

The benefit claimed for aquaculture is arguably more dubious, based on predictions in both BDP2 and NREM for increased production of 72,500 tons/year (again for the 11 mainstream projects) and values at $2.50/kg.[110] According to NREM, most of this increase is assumed to occur in Vietnam, but it is entirely unclear why additional aquaculture should constitute a benefit of these dams, as such further increases in aquaculture may well be expected to occur anyway. Moreover, as noted by the MMHSEA, aquaculture production is more costly than capture fishery, so the $2.50/kg valuation overestimates the *net* benefit.

In short, the emphasis in our report on capture fishery and sediment related impacts as the main determinants of the externality damage costs is warranted by the likely small scale of the other environmental externalities, positive and negative: their consideration is very unlikely to change the main conclusions of our report, and will have little impact on the important assumptions that will determine whether a Sambor project will result in net economic benefits to Cambodia and the LMB.

[109] The evidence form the NT2 project in Laos, that commenced operation in 2010, is mixed. The NT2 Reservoir covers a surface area of 489 km² area at its full supply level and potentially decreases to a minimum of 86 km² at the end of the dry season. The reservoir is relatively shallow with an average depth of 8 m. (Chanudet et al.,2012).

Anoxic conditions predicted by some have not proved to be a major issue (Cottet *et al*., 2016), but Phouthavong (2015) concludes that "Many high value species that initially resided in the reservoir have disappeared and are replaced by small and carnivorous species such as *Channa striata*, as well as alien species such as *Oreochromis niloticus* and *Cyprinus carpio*". It is worth noting that the research commissioned by the NT2 company (Cottet et al 2015) is largely silent on the question of the extent to which predictions about the sustainability of reservoir fisheries made at time of project appraisal have been realized in practice (none of the appraisal documents are referenced).

[110] Moreover, the assumption that aquaculture will constitute 10% of the capture fishery loss is quite arbitrary, and does not appear to be based on any empirical data.

Economic Analysis

The baseline economic analysis makes the following assumptions

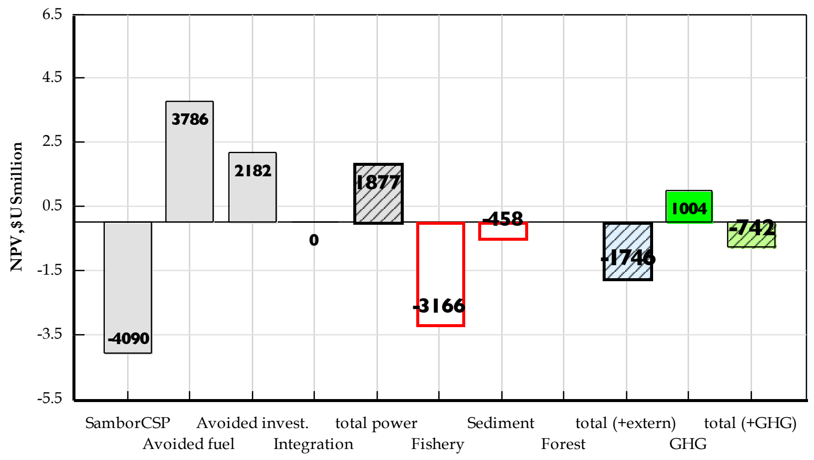
- Mean sustainable yield of the fishery declines by 0.5% per year, reflecting recent trends
- The quantity of sediment in the absence of a Sambor project declines by 1% per year, again reflecting recent trends attributable to sediment capture at upstream projects both on the mainstream as well as projects (such as LSS2) on major tributaries
- 400MW of Floating PV is implemented at LSS2 over a five-year period – 50 MW in year 2019, then 100 MW additions in the next 3 years, and 50 MW in year 5 (2023). The capital cost for each tranche is set out in Table 10-16 (so US$1,030/kW for that built in 2019, falling to US$945/kW in 2023). This is a conservative assumption: some observers see far greater declines in solar PV costs over the next 5 years.
- The capacity credit for integrated Solar PV-hydro operation is 75%. This corresponds to the number of days at which, on average, the LSS2 reservoir is not in spill condition, and the reservoir can therefore act as a storage device to shift the PV-generated output to the peak hours of the day. This is conservative because if the daily load peaks continue to shift into the late morning and early afternoon hours (see Figure 10-34), then the solar PV can make at least a partial contribution to these peaks.
- Environmental damage costs of the hydro alternatives commence in the first year of operation (an important assumption discussed further in the sensitivity analysis)
- Discount rate 8 % (discussed further in the sensitivity analysis below)

In the absence of any consideration of externalities, the economic returns of Sambor CSP are satisfactory (NPV $1.88 billion, 12.1% economic rate of return) (Table 11-28). However, the damage costs exceed this benefit, so the net benefits to the LMB are negative (US$1.75 billion).[111] The global benefits of avoided carbon emissions are substantial, but these are only of secondary benefit to the people (and the poor) of Cambodia, and even with these included, the net benefits are negative (-0.74 billion).

[111] The explanation of the difference between the fishery damage costs shown in Table 11-27, 4.64 USc/kWh, and those shown in Table 11.26, 4.31 USc/kWh has to do with the *timing* of benefits, which vary in Table 11.28 as noted in the list of assumptions, but are held constant in the simple levelised cost calculations of Table 11.26. (for example in the more detailed calculations, we take into account that full energy production at CSP commence only in (as per the CSP FS), whereas in table 11.26, the full energy production is taken as constant (however, the damage to fishery starts the moment the dam is finished).

Table 11-28. Economic returns, Sambor CSP.

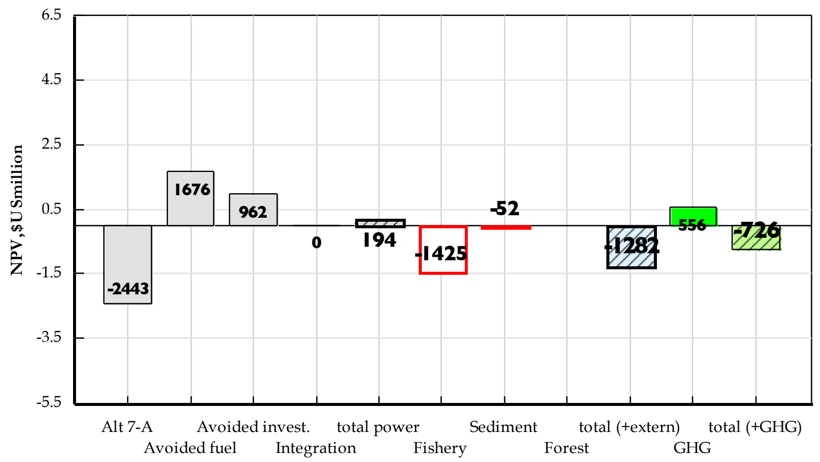
SamborCSP	Distribution of economic returns (at constant prices)			
Discount rate	8.0%			
	economic returns	NPV, $USb	Levelised costs&benefits	USc/kWh
ERR (power)	12.1%	1.88	Power	-5.99
ERR (incl. externalities)	negative!	-1.75	Fishery damage	-4.64
ERR (incl. GHG)	6.3%	-0.74	Sediment damage	-0.67
GHG valuation	@WorldBank ($30/tonCO2+)		total	-11.30
			energy benefit	5.55
			capacity benefit	3.20
persons displaced	**21440**		Net	**-2.56**



The economic returns of Alt-7A are significantly lower (Table 11-29) at 8.8%: the NPV of benefits is US$194 million, as compared to $1,877 million for Sambor CSP. However, the fishery damage costs are less than half those of CSP, so when externalities are taken into account, the net benefit is minus US$1.28 billion, compared to minus $1.75 billion for Sambor CSP.

Table 11-29. Economic returns, Sambor Alternative 7-A

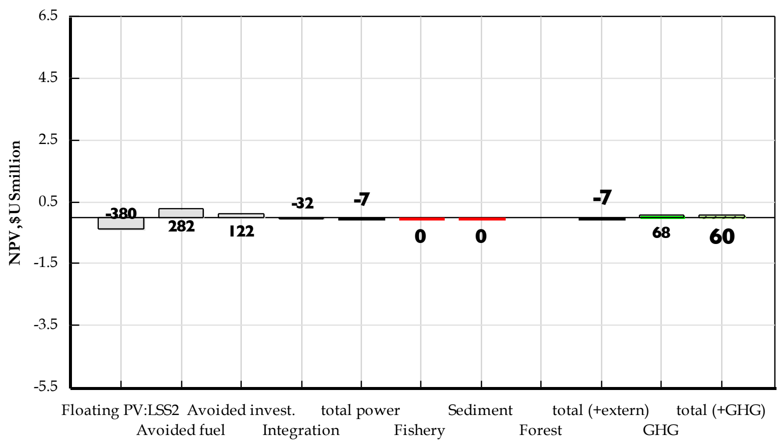
Alt 7-A	Distribution of economic returns (at constant prices)			
Discount rate	8.0%			
	economic returns	NPV, $USb	Levelised costs&benefits	USc/kWh
ERR (power)	8.8%	0.19	Power	-8.12
ERR (incl. externalities)	negative!	-1.28	Fishery damage	-4.74
ERR (incl. GHG)	negative!	-0.73	Sediment damage	-0.17
GHG valuation	@WorldBank ($30/tonCO2+)		total	-13.03
			energy benefit	5.57
			capacity benefit	3.20
persons displaced	**2115**		Net	**-4.26**



The economic returns of the 400 MW floating PV are shown in Table 11-30. This is a much smaller project than the two hydro alternatives at Sambor, so when displayed on the same scale, the NPVs appear small. The rate of return when externalities are included, at 7.8 %, is higher than for either the two hydro alternatives.

Table 11-30. Floating solar PV.

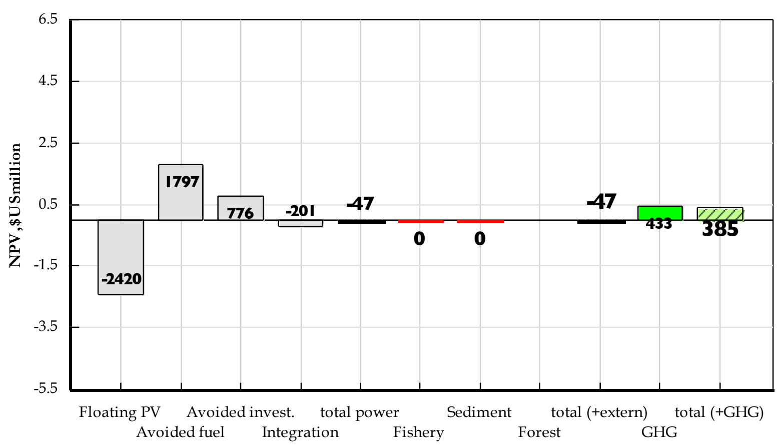
Floating PV:LSS2	**Distribution of economic returns (at constant prices)**			
Discount rate	8.0%			
	economic returns	NPV, $USb	Levelised costs&benefits	USc/kWh
ERR (power)	7.8%	-0.01	Power	-8.10
ERR (incl. externalities)	7.8%	-0.01	Fishery damage	0.00
ERR (incl. GHG)	10.8%	0.06	Sediment damage	0.00
GHG valuation	@WorldBank ($30/tonCO2+)		total	-8.10
			energy benefit	5.56
			capacity benefit	2.40
persons displaced	0		Net	-0.15



A better comparison would be to scale the floating solar PV to deliver the same energy as, say, the hydro Alternative_7A, as shown in Table 11-31.

Table 11-31. Floating solar PV, scaled to the same energy as Alt_7A.

Floating PV	**Distribution of economic returns (at constant prices)**			
Discount rate	8.0%			
	economic returns	NPV, $USb	Levelised costs&benefits	USc/kWh
ERR (power)	7.8%	-0.05	Power	-8.10
ERR (incl. externalities)	7.8%	-0.05	Fishery damage	0.00
ERR (incl. GHG)	10.8%	0.39	Sediment damage	0.00
GHG valuation	@WorldBank ($30/tonCO2+)		total	-8.10
			energy benefit	5.56
			capacity benefit	2.40
persons displaced	0		Net	-0.15



At this scale of solar PV, the integration issues would become more significant, though not necessarily negatively so. The main problem is rapid fluctuation of PV output due to passing cloud cover – but if, for example, all hydro projects in Cambodia had some floating PV, the diversity effect would significantly reduce the requirement for energy storage systems to mitigate the short term output fluctuations – recent studies in Spain have shown the value of such spatial diversity.[112]

However, it is fairly clear that compared to the two hydro alternatives, solar PV is by far the best option, the **only one with a positive economic rate of return when externalities are included**.

Mitigation options for Alt 7A

The extent to which the three mitigation options change the evaluation is shown in Table 11-32. Alt 7B has low impact turbines, resulting in a reduction of fishery damage costs, equal to 1.96 USc/kWh. However, as noted, these turbines will likely involve higher costs (of 1.9 USc/kWh), so a small net benefit. However, the $1billion for screens is not justified by the achieved benefits. Over time, the cost of low-impact turbines may well fall (and achieve a lower efficiency penalty) – but the minor improvement in net benefit will not make Alt-7B a viable option.

Table 11-32. Impact of mitigation options at Alt 7A (as change in levelised cost of energy, USc/kWh).

		Increase in benefits	Increase in cost	Net change
		[1]	[2]	[3]
Alt-7B	low impact turbines	1.96	-1.90	0.06
Alt-7C	Screens	0.82	-3.10	-2.28
Alt-7D	low impact turbines+screens	2.47	-5.50	-3.03

[1] namely the reduction in fishery damage costs, from Table 11-26.
[2] from Table 11-8

Sensitivity Analysis

Several important assumptions are worth assessment at this stage (leaving the formal risk assessment to Chapter 12). The first is the discount rate, which as discussed above plays an important role when comparing NPV and levelised costs per kWh. However, as shown in Table 11-33, the choice of discount rate does not change the relative ranking of the options. The solar PV option has zero environmental damage costs, and the best net benefit, regardless of discount rate. There is no need to apply different discount rates to different costs and benefits.

112 This study (de la Parra *et al*., 2015) examined the spatial diversity effect of 6 solar PV projects scattered over an area of some 315 km2, all fitted with vertical-axis trackers. Using 1-second data over a one year period the study found significant savings in ESS required when this was located at a centralized collection point.

Table 11-33. Sensitivity to the discount rate: levelised cost USc/kWh.

		Sambor CSP	Alt 7-A	Solar PV
Power cost	6%	4.88	6.61	6.93
	8%	5.99	8.12	8.10
	10%	7.26	9.8	9.34
Damage costs	6%	4.51	4.71	0.00
	8%	4.64	4.74	0.00
	10%	4.78	4.76	0.00
Net benefit	6%	-1.76	-3.20	0.66
	8%	-2.56	-4.26	-0.15
	10%	-3.49	-5.47	-1.01

A second concern the timing of externality damage costs. The assumption in the analysis is that the full impact is experienced in the first year of operation (as presented in the previous tables). This may well be a pessimistic assumption – some of the impacts may only be felt after several years. On the other hand, assuming zero damages during construction is optimistic: not only may the start of reservoir filling commence many months before first commercial power, but the construction – particularly of a massive mainstream dam (as for Sambor CSP) – is massively disruptive of natural flow, involving construction and demolition of coffer dams, and temporary diversion channels. Indeed, fishways may only function properly once the project is fully operational, so both upstream and downstream passage will be severely affected during the construction phase.

As shown in Table 11-34, these assumptions make no material difference to the NPV of damage costs. Obviously, if damage costs only start gradually after power generation starts, the NPV of damage costs is lowest; if damage costs start already during construction – which would appear to be most likely - the costs will be higher.

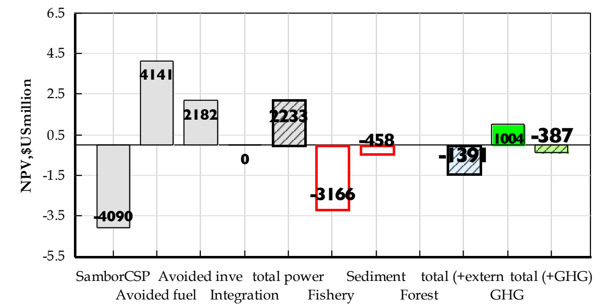
Table 11-34. Impact of the timing of fishery damage costs (Sambor CSP).

	Damage costs in construction	Damage costs in operation	NPV fishery damage cost (NPV, $USm, 8% discount rate
Baseline (as in above results tables)	None	100% of values shown in Table 11-25	$3,166m
Damage costs increased gradually	None	40% in year 1, increasing to 100% in year 4	$2,856m
Damage costs begin in first year of construction	10% in year one, increasing to 50% in last year	60% in first year, reaching 100% in year 5	$3,370m

The third, and arguably the most important, is the valuation of benefits, which are primarily a function of the forecast for future fossil fuel prices. As noted, the above assessment is aligned to the mid-2017 forecast of the World Bank, resulting in a valuation of the avoided cost of thermal energy (based on gas) at 5.55USc/kWh. If we assume a more rapid increase in LNG price, with US$10/mmBTU reached by 2025 rather than by 2030, then the levelised avoided cost of energy increases to 6.17 USc/kWh.

At this price, the comparison of the floating PV option and Sambor CSP shifts even further in favour of the PV option, as shown in Figure 11-11. Now the net economic benefit of the PV option is a positive $152 million, whereas Sambor CSP still shows a significant net *loss* of $1,391 million.

SamborCSP	**Distribution of economic returns (at constant prices)**			
Discount rate	8.0%			
	returns	**$USb**	**Levelised costs&benefits USc/kWh**	
ERR (power)	12.9%	2.23	Power	-5.99
ERR (incl. externalities)	4.5%	-1.39	Fishery damage	-4.64
ERR (incl. GHG)	7.1%	-0.39	Sediment damage	-0.67
GHG valuation@WorldBank ($30/tonCO2+)			total	-11.30
			energy benefit	6.17
			capacity benefit	3.20
persons displaced	**21440**		Net	**-1.93**



Floating PV	**Distribution of economic returns (at constant prices)**			
Discount rate	8.0%			
	returns	**$USb**	**Levelised costs&benefits USc/kWh**	
ERR (power)	8.8%	0.15	Power	-8.10
ERR (incl. externalities)	8.8%	0.15	Fishery damage	0.00
ERR (incl. GHG)	11.8%	0.58	Sediment damage	0.00
GHG valuation@WorldBank ($30/tonCO2+)			total	-8.10
			energy benefit	6.17
			capacity benefit	2.40
persons displaced	**0**		Net	**0.47**

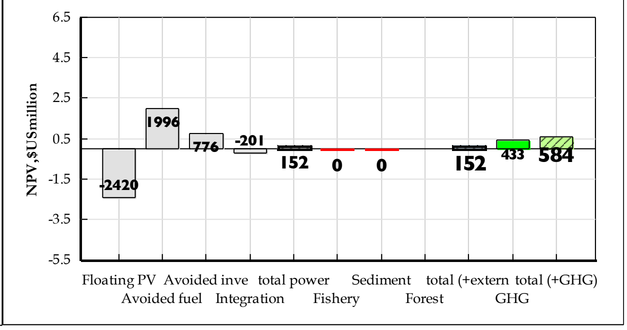


Figure 11-11. Comparison of Sambor and floating solar PV for higher gas prices.

Distributional Analysis

Who wins and who loses? The net power benefits will be distributed among EdC's consumers, the developer, and Government. The shares to each will be settled by negotiation between Government and the developer, and by the taxes (or tax concessions). If we assume Government captures 35%, EdC's consumers 50% and the IPP 15%, then the distribution of costs and benefits among the stakeholders would appear as shown in Figure 11-12. The GHG emission benefit accrues to the global community; sediment damage to Vietnam, and Fishery Damage 85% to Cambodia and 15% to Vietnam.

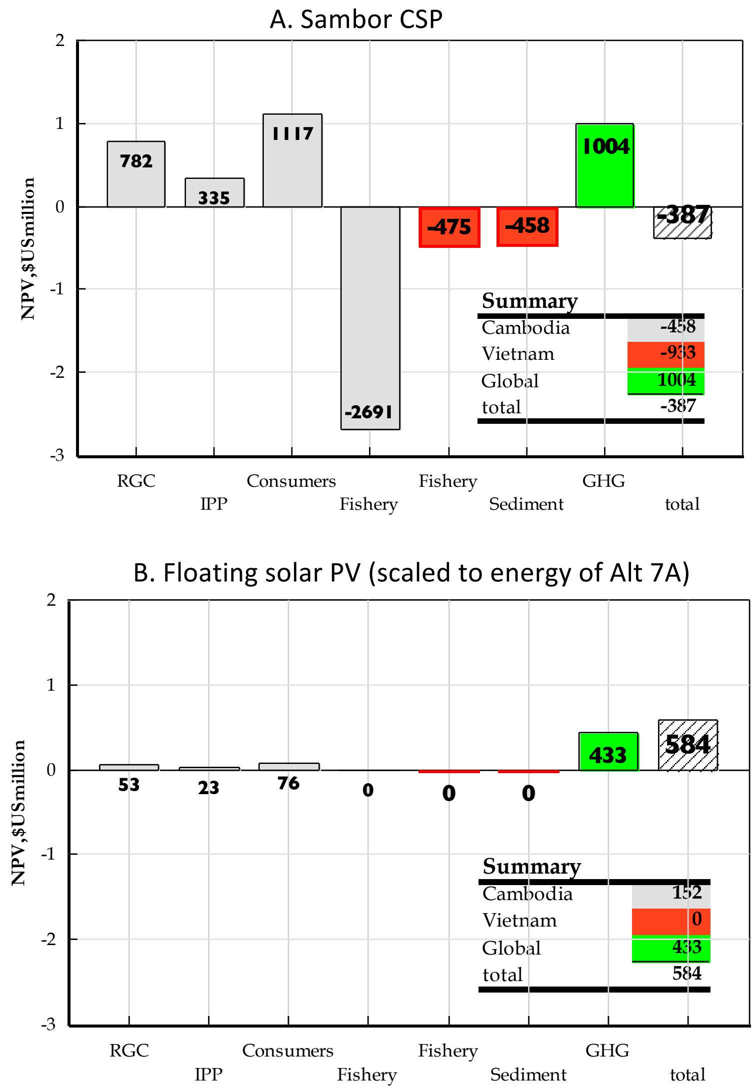


Figure 11-12. Distribution of costs and benefits (as NPVs, 8% discount rate).

For a large mainstream hydro project at Sambor, the biggest loser is Vietnam. Cambodia is also a loser, because its fishery damages far outweigh the power benefits: Vietnam, however, receives no benefits. However, for the floating PV, *nobody* loses. Vietnam is unaffected, and Cambodia receives only power benefits.

Financial Assessment

This preliminary assessment of the impact of financing options on the financial cost of solar PV power to EdC is based on the alternative financing packages shown in Table 11-35 – which ranges from commercial debt to concessional carbon finance. We assume that the entire debt is financed under the terms shown – in practice there may well be several debt tranches financed under different terms, but our purpose here is simply to illustrate the range of potential PPA prices.

Table 11-35. Financing alternatives.

	Commercial Debt	Commercial debt+IFI PRG	IBRD finance (libor+fixed spread)	Concessionary carbon finance
Equity fraction	30%	30%	30%	30%
Debt fraction	70%	70%	70%	70%
Post-construction tenor(1)	10	12	15	20
Interest rate	7%	5.5%	4%	1.25%
Return on equity	15%	.15%	15%	15%
PRG cost (2).		0.25%		

(1) assuming a grace period during construction
(2) Assuming leverage of 1.6

The cost of equity will depend on the risk perception of investors, and certainly in the case of larger scale projects, on the risk perceptions of foreign investors (and on country risk in particular). In practice, with some IFI involvement, the target equity return may be slightly lower (in consequence of the due diligence of the IFIs that is based on worldwide experience: for this simulation, we assume 15% for all options. [113]

Other assumptions in the financial analysis are as follows

- The calculations are in nominal US$,
- The PPA assumes a constant value denominated in US$ (following the PPA at LSS2) (which means a falling tariff in real terms),
- The life of the PPA is 25 years,
- Interest is capitalized,
- Loans provide for repayment of principal in equal installments, with interest calculated on the average of opening and closing balances each year,
- With capital costs decreasing over time, the results are presented just for a first 50 MW tranche assumed at 2019 price levels (so US$1,030/kW, as in the economic analysis). It is assumed there are no import duties or VAT, so the financial and economic overnight capital costs are the same.
- Debt service reserve account of 6-months cover, 50% to be funded up front.
- No additional costs for integration and transmission.
- The tariffs are exclusive of any corporate income tax. Such a tax is a transfer payment which does *not* in fact fall on the IPP developer: the greater the tax rate, the higher must be the tariff.

[113] We doubt the value of any complex calculation of equity returns based on the so-called “Capital Asset Pricing Model.” This model requires, among many other assumptions, a value of “beta”, the sensitivity of investors returns to market returns, and “risk-free rates” - plausible for the USA or countries with established capital markets, but which would require quite arbitrary assumptions for a country like Cambodia.

The results of this simulation are shown in Table 11-36. The concessionary finance will highly unlikely cover the entire debt, so the probable range of PPA price is between 8 and 10 USc/kWh. The Debt service cover ratios (DSCR) are highly satisfactory.

Table 11-36. Indicative financial results.

	PPA price	DSCR	WACC
Commercial Debt	10.2	1.51	10.4
Commercial Debt+IFI PRG	10.0	1.41	8.4
IBRD finance	8.9	1.65	7.3
GCF Concessionary finance	7.5	2.29	4.5

When likely integration costs are added (which from the economic analysis can be seen to add about 10% to the capital cost), the required PPA tariff increases as shown in Table 11-37, by about 0.9 USc/kWh for commercial finance.

Table 11-37. Impact of integration costs: PPA price in USc/kWh.

	PPA price PV only	PPA price including Integration costs
Commercial Debt	10.2	11.1
Commercial Debt+IFI PRG	10.0	10.9
IBRD finance	8.9	9.6
GCF Concessionary finance	7.5	8.1

Figure 11-13 shows the results of a full sensitivity analysis for most of the uncertainties in such calculation. This shows a typical range of uncertainty of $\pm$0.5 USc/kWh.

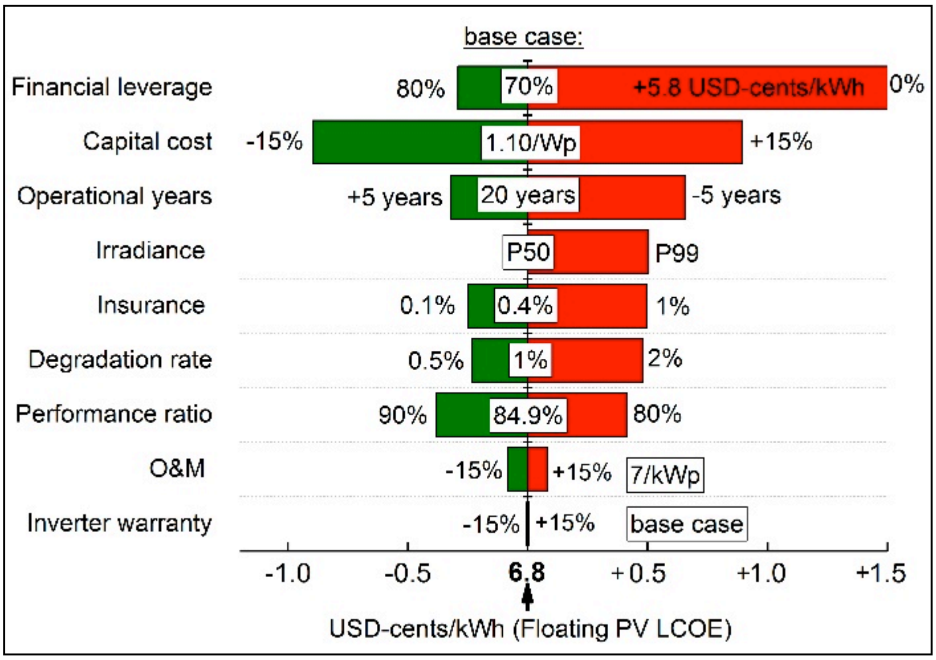


Figure 11-13. Sensitivity analysis. Source: SERIS Financial model.

Note that these results are for a first tranche of 50MW financed in 2018 at the then prevailing price. When we use 900$/kW as may be expected by the early 2020s, the tariffs are significantly lower. As experience with the technology grows, the risk perceptions will decrease, and equity returns can be expected to be reduced. The impact of these trends is illustrated in Table 11-38.

Table 11-38. Tariffs at future PV system prices.

	Baseline $1030/kW	2025 prices $929/kW	2025 prices, 12% equity return
Commercial Debt	10.2	9.6	8.9
Commercial Debt+IFI PRG	10.0	9.4	8.6
IBRD finance	8.9	8.3	7.7
GCF Concessionary finance	7.5	7.0	6.5

This analysis can also be reversed, namely by fixing the tariff, and asking what equity return would be available: the results are shown in Table 11-39.

Table 11-39. Equity return at given tariffs (excluding integration costs, 10% reduction in CAPEX).

Tariff, USc/kWh	6	8	10
Commercial Debt	0.3%	8.5%	16.9%
Commercial Debt+IFI PRG	3.9%	10.1%	17.2%
IBRD finance	5.1%	13.5%	22.6%
GCF Concessionary finance	8.7%	20.5%	31.3%

Hydro Options

It is very difficult to see how Sambor CSP can be financed without some degree of credit enhancement. Under the same assumptions for commercial financing (10-year post construction tenor and 7% interest rate), the tariff required for a 15% FIRR is 8.96 USc/kWh (again, under the assumption of no tax or transfer payments). If financed under the same terms as LSS2 (6.5% interest over 15 years), this falls to 8.3 USc/kWh. We have no details about the exact source of finance, but a 15-year post construction tenor with 5 years grace during construction appears to have a considerable element of concessional finance, presumably from China.[114]

The tariff for Alt_7A is considerably higher at 13.12 USc/kWh at pure commercial finance, and 12.18 USc/kWh at LSS2 debt terms – though at such tariffs, the DSCR is good. We doubt that at such PPA price, the hydro project would be of much interest to EdC and RGC.

Table 11-40. Summary of tariffs, 15% FIRR.

	tariff	DSCR
Commercial		
Sambor CSP	8.96	1.31
Alt 7A	13.12	1.25
LSS2 financing		
Sambor CSP	8.34	1.54
Alt 7A	12.18	1.47

[114] It may be noted that this calculation is under the assumption that 100% of energy generation is available in year 1 of operation. With the actual plan as presented in the CSP FS of only 20% of energy in year 1, reaching 100% only in year 5, the necessary tariff is above 12 USc/kWh, so quite infeasible.

Conclusions of the Economic & Financial Analysis

Hydro Options at Sambor

If externalities were of no concern, construction of a large hydro project at Sambor, along the lines proposed by the CSP FS for 2,600 MW, would be economically rational, with a levelised economic cost of 6.0 USc/kWh, as compared to 5.0 USc/kWh at LSS2.[115]

However, all the hydro options impose very large externality costs on downstream fisheries and on the Mekong delta: in the case of CSP, fishery damage costs amount to 4.64 USc/kWh, compared to 4.74 USc/kWh for Sambor Alt_7-A under the assumption of 80% upstream passage success (even though in absolute terms the fishery damage cost for CSP is five times larger than at Alt_7-A, the sheer scale of CSP spreads these damage costs over 11,000 GWh per year rather than 4,240 GWh (for Alt_7-A).

The analysis suggests the potential benefits of the fish friendly turbine Alt_7-B option: depending on the results of a commercial scale demonstration, the fishery damage costs can be cost-effectively reduced over Alt_7-A. Although the production cost before externalities increases by 1.9 USc/kWh, the fishery damage costs decrease by 2.0 USc/kWh. Such designs should certainly be assessed in more detail at the detailed feasibility study stage. However, the incremental benefits of fish screens in reducing fishery damage costs are insufficient to justify the high cost ($1 billion in additional capital cost).

Whether a 95% upstream passage success rate can in fact be achieved is uncertain: there remains disagreement even among experts. The main difficulty for the fish passage design is the sheer diversity of the fishery: to achieve 95% for a single species may be reasonable, but to achieve 95% *on average* implies the success rate for some species would have to approach 100% to offset those for which only 90 % may be achieved.

Moreover, quantification of the damage costs on fisheries and on the Mekong delta are subject to high uncertainty. Some studies hold that the value of the fishery can be measured by the retail market price of fish delivered, with valuations that run into the billions of dollars (that far exceed the benefits of the additional electricity); others note that that the fishery is largely unsustainable anyway, and would decline from over-fishing even in the absence of a Sambor dam; and still others point out that what is really at stake is the livelihood and food security of large numbers of the rural poor, and that while the relatively better off urban consumers could afford to adjust to other forms of protein, for the rural poor the impact would be catastrophic. In any event, however measured and valued, the share of total GDP contributed by fisheries is in decline in both Vietnam and Cambodia.

Such valuation arguments are further compounded by disputes over even more basic questions about the discount rate. Economists argue that the choice of discount rate can be determined precisely by application of the tools of economic analysis – grounded either in the principles of welfare economics and inter-generational equity, or of the economic opportunity cost of capital – though whatever approach is used requires a range of further assumptions. In reality it is about the

[115] At 8% discount rate. At 10%, Sambor has a levelised cost of 6.8 USc.kWh, LSS2 5.4 USc/kWh.

weights that society places on consumption in the short term against consumption in the longer term, judgments about which can only be made by Governments on behalf of their country.

The damage costs are subject to high uncertainty, not least because of uncertainties about the proportion of migratory fish having spawning ground upstream of Sambor, and the extent of damage and sediment capture at hydro projects above Sambor. As noted in Chapter 8, there are also many uncertainties about the ability to model the impact of Sambor on the sustainable yield of the fishery, and our estimates of fish mortality of the new fish-friendly turbines are not based on detailed modeling (or field experience) but on extrapolations of the very preliminary data from the developers of such turbines (which have yet to be proven at commercial scale.

Whatever may be the resolution of these uncertainties, the CSP design will result in catastrophic damage to the Tonle Sap fishery. Moreover, CSP cannot benefit from low cost finance (say with a partial risk guarantee from the World Bank which would lower the commercial interest rate by 2-2.5 % - because this would require no objection from Vietnam – and which is very unlikely to be provided). What can be said with considerable certainty is that all of the alternatives studied by this report will have a much lower impact on the fishery than CSP.

The principal question is what decision should the RGC make on Sambor given these various uncertainties – the results of which may only become apparent once a Sambor project is built, at which point the damages may be irreversible. This question is the subject of the risk assessment provided in the next Chapter.

In short, only under the most unrealistically optimistic assumptions can one demonstrate net economic benefits for a mainstream hydro project, even when the most advanced mitigation techniques are employed (small reservoir size to maintain downstream flow velocities, fish friendly turbines, extensive upstream fish passages, fish screens, and sediment flushing). The argument that reservoir aquaculture can offset downstream capture fisheries is wishful thinking, unsupported by the evidence of the international experience.

Floating Solar PV

Based on the economic analysis one may say with high certainty that the expected economic returns, when probable environmental damage costs are included, are much greater for the floating solar PV augmentation at LSS2 than for any Mekong mainstream hydro project, and most certainty greater than for even the Alt 7A alternative whose engineering design provides the best chance for mitigating the downstream damage costs. **Quite simply, the floating solar PV project has no material negative environmental externalities**: the risk profile of this option – to be discussed further in Chapter 12 – is very low, and will completely avoid the inevitable controversy of a mainstream hydro project – whether over the 20,000 people that would need to be resettled at Sambor CSP, the impacts on Vietnam's Mekong delta, and above all the uncertainty over the damage to the downstream Cambodian fishery.

The present PPA tariff at LSS2 is 6.95 USc/kWh. Neither the Sambor hydro options, nor the floating PV can reach this level of tariff in the short term, though future price decreases in solar modules will result in prices that may reach this level. The key will be competitive bidding for the EPC to deliver the PV panels. To be sure, there remains some uncertainty over integration costs, but the good news is that these costs – particularly for fast-response storage to even out the fluctuations associated with cloud cover variations, are falling as rapidly as the PV module costs have fallen over the past few years.

Moreover, the analysis shows that credit enhancements obtainable through the IFIs offers great scope for reduction of the tariff. In the absence of significant environmental damage costs, the safeguards policies of the IFIs that are required for eligibility for IFI involvement are straightforward – which are simply unavailable to a mainstream project likely to be vigorously opposed by Vietnam.

The financial analysis has been presented exclusive of tax. Corporate income tax is a transfer payment from consumers of electricity to the Government. The RGC may of course wish to benefit from Sambor or from a solar PV project, for which a variety of mechanisms are possible, including corporate income tax, royalties, or other negotiated payments.

The distributional analysis highlights the unequal shares of costs and benefits for a mainstream project at Sambor. Vietnam experiences only costs, whereas at least Cambodia generates substantial power benefits. By contrast, the floating PV project has no losers: Vietnam is unaffected, and Cambodia has only winners.

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12 RISK ASSESSMENT

At its inception, this assessment of Sambor Dam alternatives set a performance standard of 95% success for upstream passage (fish pass efficiency) and also for downstream survival. Those goals have driven the exploration for a maximal mitigation approach that is practical and achievable. This performance standard reflects globally-recognized best practices for sustainable hydropower, as enshrined in the Mekong River Commission (MRC) paper on sustainable hydropower (MRC, 2015), and sets a new global standard for sustainable hydropower. To our knowledge, these performance standards have not been attained at any other hydropower facility. The essential question is whether the Sambor 7 (Sambor Alt_7) design and operations would achieve them in reality. From what we know about fish behavior and fish passage designs, we can only state that the measures incorporated in the NHI Sambor conceptual designs are more likely to achieve these performance standards than any other alternative that we assessed, or that we could conceive.

Nevertheless, the Natural Heritage Institute (NHI) team acknowledges that the scientific studies performed in this concept study do not provide enough information to be entirely confident. In theory, these mitigation measures should be successful, but in fact they are novel and have not been tested in the real world. And, the record of success in designs that have been tested counsels caution in predicting results. The empirical record on upstream fish pass efficiency for advanced fish passage facilities and dam operations around the world for non-salmonids, such as the tropical fish inhabiting the Mekong, averages only about 20% (Noonan *et al*, 2012). Several facilities have reported 0% efficiency.

We must therefore conclude that even the maximally efficient designs that the NHI team has developed carry an appreciable degree of risk. It is important to understand that the consequences associated with this degree of risk in a system such as the Mekong can be unacceptably large. For instance, if these most advanced measures achieve only an 80% upstream fish pass efficiency, rather than the 95% goal, the population model for Alt_7-A predicts a cumulative decline in harvestable biomass below the dam of 45%. Even if mortality rates in fish-friendly Alden turbines is only in the 1-5% range as claimed, if upstream passage rate is only 80%, then in any event the *aggregate* loss of MSY (Maximum Sustainable Yield) cannot be less than 20%. Moreover, if there is non-zero mortality of larvae (as would be the case in very large reservoirs where flow velocities are insufficient), aggregate survival is further reduced, no matter how low is the mortality of turbine passage. This is dependent on the operations management of the project, which calls for drawing down the reservoir to assure sufficient flow velocity: whether the operator would actually do this as required constitutes a further risk factor.

As these predictions themselves are based on assumptions that are fraught with uncertainties, the only conclusion we can make with absolute certainty is that the risk associated with any dam design and operation, sited in the midst of the world's greatest corridor for migratory fish biomass, is sufficiently large that the prudent course is for the Royal Government of Cambodia (RGC) to investigate a full range of renewable power options, including those that may avoid damming the mainstream Mekong. We can also state with high certainty that whatever may be these uncertainties, the original 2,600 MW design concept for Sambor will have a substantially higher risk of irreversible damage on downstream fisheries and the Mekong delta than the NHI Sambor Alt_7-A design.

It is important to note that, while the level of detail presented in this concept design is much greater than is typical of a *pre-feasibility study*, if proponents subsequently undertake a more extensive feasibility study, the uncertainties noted at the current stage of analysis must be addressed and resolved for review by the RGC, the MRC, its member countries, and civil society in general.

Valuation Issues

This Chapter expresses risk as a judgment about the probability that the costs of a hydropower project exceed its benefits: in other words, about the *economic consequences* of investment decisions at Sambor.

However, there are also ethical and distributional dimensions to risk – even if the benefits of power generation exceed the probable *economic* damages to the downstream fishery, these damages may fall on a narrow segment of the population (predominantly poor and rural fishermen) who receive few of the power benefits of the project. And, even if difficult to value in monetary terms, society also gives *existence* value to natural eco-systems (perhaps most visibly demonstrated in the case of dolphins): whatever may be the economic damage, the *avoidable* loss of unique species or ecosystems is seen by many as unacceptable. However, these equity and ethical considerations constitute attributes that are distinct from economic considerations.

For example, one could value dolphins purely by the economic net benefits of the related tourism, whose economic benefits are estimated at a few hundred thousands of dollars per year.[116] These will be of no consequence to a cost-benefit assessment (CBA) or economic risk assessment whose impact is in a few hundreds of millions of dollars. Nevertheless, the *existence* (or “cultural”) value of dolphins should not be ignored simply because it does not appear in a CBA for lack of *economic* significance. Rather, the RGC should expressly consider the risks to the existence value of dolphins (as set out in Chapter 9) as a *separate and distinct attribute*, to be explicitly traded off against the economic benefits of a hydro project.

The Hierarchy of Risks

For a potential hydropower investment at Sambor to produce the desired result of net economic benefits requires calculations both of costs and of benefits. Both have high uncertainty.

Benefits

The economic benefits of a hydro project at Sambor have been assessed as the avoided cost of the thermal alternative. The construction costs of a gas-fired combined cycle project powered by Liquid Natural Gas (LNG) are known with reasonable certainly, but the main uncertainty is that of the future price of gas: over the past decade this has varied from US$6/mmBTU to US$16/mmBTU (see Figure 11-4). In this report, we have used the latest World Bank forecast of US$10/mmBTU as the average long-term price.

Hydro Production Costs

One can also be reasonably confident of the cost estimates for Sambor CSP and the basic Sambor Alt_7-A design, which follow well established engineering experience, and include the usual

116 See Chapter 9.

provisions for contingencies. In hydro projects the main uncertainty concerns civil engineering costs associated with geotechnical foundation conditions and tunneling risks. A Sambor project involves none of the latter, and the geotechnical conditions are generally satisfactory. Therefore, with the production costs of the Sambor hydro alternatives in the range of 6.8 USc/kWh (for CSP) to 9.1 USc/kWh for Alt_7-A and 11 USc/kWh for Alt_7-B, in the *absence of externalities* one can be reasonably confident that hydro development is economic.

Externalities

We summarize the key uncertainties in the calculation of the externality damage costs of hydro projects as shown in Table 12-1.

Table 12-1. Summary of uncertainties relating to fishery damages.

Uncertainty	Baseline assumption in this Report	Range of uncertainty	Options for Resolution
Impacts of upstream dams on hydrology	Not considered	Several upstream dams (and notably those in China) have significant seasonal storage capacity, which may change the seasonal patterns of inflow and water levels into the Ton Le Sap	In the absence of a comprehensive basin model of Mekong hydrology including China, and information on operating policies of upstream dams in China, only the future will tell whether the total fishery volume in the LMB will decline as a result.
Proportion of the LMB fishery that is migratory	38%	Somewhat speculative. The value chosen is from a single reference in the literature (which many other studies have also used)	While the total volume of fish in the LMB is known with reasonable certainty, the extent to which current yields are sustainable is controversial.
Volume of migratory fish presently passing the Sambor site	70% (of the total migratory population)	Speculative in the absence of better field data, and based purely on anecdotal information (many species can be observed passing the Sambor site in large numbers)	Improved field data are needed. We urge its initiation as one of the highest priorities for the MRC.
Fishing mortality	Fish populations in the LMB are exploited at rates that maximize yield	Little is known about rates of fishing mortality in the Mekong, and few estimates have been published.	The assumption probably understates the impact of the dam. The fishery that experiences high rates of migration through the Sambor reach is heavily exploited by fishers.
Impact of hydropower projects on the migratory fishery upstream of Sambor	Not included	Unknown	Depends on actual impact of Xayaburi, Don Sahong and LSS2. The absence of a comprehensive dynamic model of the Mekong fishery is a severe handicap. This needs to be initiated by the MRC as soon as possible.
Ability of migratory fish to find alternative spawning sites	Not considered	Unknown	Only the construction of the dam can provide certainty – at which point impact may be irreversible

Uncertainty	Baseline assumption in this Report	Range of uncertainty	Options for Resolution
Upstream fish passage success	80%	95% might be achieved, but past international experience shows average passage rates to be in the 40-60% range even for well designed fishways optimized for just a few species.	Operating experience from Xayaburi and LSS2, now under construction, can provide better confirmation of the adequacy of current designs. Actual upstream passage success can only be predicted, not confirmed.
Energetic costs of Upstream passage of adults to spawning grounds.	The upstream passage estimates assume that individuals experience no additional mortality or diminished reproductive capacity associated with upstream passage via ladders or other passes	In reality, some mortality and diminished reproductive capacity might be expected due to the high energetic costs associated with passage and the increased likelihood of predation in dam vicinity.	The results presented here may therefore be conservative. This assumption tends to understate the actual impacts. It bears on the likelihood of achieving 95% success rate in upstream fish passage. This risk is exacerbated if there is a major departure from the performance goal.
Larval passage downstream	95%	The main determinant is the flow velocity through the reservoir, which requires the reservoir to be drawn down at certain time.	We can be reasonably confident that the very large size of the CSP reservoir will result in close to 100% larval mortality: the 7A design and operation is deemed to provide the minimum velocities to ensure high survival. Whether the operator will actually draw down the reservoir when required to maintain velocities constitutes a risk fact: this would be difficult to monitor and enforce in practice.
Downstream fish passage	At 95% upstream passage, between 6% – 19% decline in MSY	At the time of writing, our ability to model blade strike mortality is limited to conventional Kaplan turbines.	See switching value analysis below. Further modeling studies will be available by December 2017 to be reported in the final version of this study
Population structure:	The species of fish included are assumed to comprise a single interconnected meta-population in the LMB	Potential impacts will be highly sensitive to this assumption. This assumption also tends to overstate the probable impacts of the dam and is therefore appropriately conservative. If there are multiple populations using different reaches of the river, the dam may affect only some, not all of these populations.	In the absence of a comprehensive LMB fishery dynamics model that includes all of the major species, it is difficult to narrow the range of this uncertainty.
Value of fish	$1.5/kg	Some past studies have attributed values of as much as $3.50/kg. Recent value chain studies suggest net added value of at least $1/kg for Snakehead (see Figures 10-9 and 10-10)	The actual economic impact of severe decline in sustainable fishery yields will depend on the relevant regional multipliers, particularly in the Ton Le Sap area. But in the absence of any rigorous regional economic impact studies, multiplier values are speculative.

Several conclusions may be drawn from this list of uncertainties:

- The Mekong River is unique in its diversity of species. There is no comparator in international experience. Therefore, the predictions of upstream passage success are based in expert judgement, which is not uniform among professionals. The NHI study team believes that the extensive fishway facilities described in Chapter 7 incorporate all features known to improve survival rates and are the best that can possibly be designed. But, to achieve 95 % average passage across so wide a range of species implies that some species achieve passage successes close to 100%. This is unprecedented.

- Predictions of downstream fish passage depend on the accuracy of modeling of blade strike, screen impingement, reservoir flow velocity, and fishery dynamics. At the time of writing we have conducted only some preliminary studies, with particular gaps on the performance of new fish friendly turbines – which is difficult given that there is as yet no full-scale commercial demonstration of these designs.

- Several of the uncertainties cannot be narrowed by improved modeling, but would need to await actual construction of a Sambor dam, at which point the impacts may be irreversible.

- The combination of large uncertainties in our understanding the migratory fish behavior under the wide range of species at risk and the untested nature of the mitigation measures means that the risks associated with even the fully mitigated Sambor Alt_7-A option are very large.

Switching Values Analysis

Upstream Passage

In the fishpass design discussion in Chapter 7 and in the economic analysis of Chapter 11, we present a range of mitigation options to improve the fish survival of the Sambor Alt_7-A baseline design. The hypothesized improvements in performance are shown in Table 12-2. Reliable model results are available only for the baseline option Sambor Alt_7-A: the improvements attributable to improved turbines are based simply on preliminary information from the designers of new turbines – but as noted, there is as yet no full scale commercial demonstration of such machines. In any event, these MSY loss estimates should be seen as placeholders to be revised in our final report.

Table 12-2. Hypothesized improvements for the mitigation options (total MSY loss, as %).

	% upstream passage			
Option	95%	80%	60%	40%
Alt_7-A	19%	45%	81%	100%
Alt_7-B = 7-A+improved turbines	8%	23%	45%	90%
Alt_7-C= 7-A+ coarse fish screens	10%	37%	72%	80%
Alt_7-D= 7-A+ coarse fish screens + improved turbines	6%	21%	42%	50%

This analysis can be turned around. Instead of making an assumption on MSY (subject to considerable uncertainty) and then calculating net benefits, we can ask what would be the required value of the MSY loss assumption to ensure a positive result (i.e. below which net economic benefits are positive). Such a value is known in cost-benefit analysis as the “switching value.”

Table 12-3 shows a sensitivity analysis of the loss of MSY as a function of the upstream passage rate and the value of fish ($/kg). The switching values for MSY shows the **maximum** value of MSY that would assure net economic benefit. Note that these switching values do not need any modeling of downstream passage success (mortality from blade strike or barotraumas) – they simply inform what the results of the modeling should be if net benefits are to be achieved, given a particular cost and efficiency of the turbines.

Table 12-3. Switching values analysis.

		Upstream passage	Fish value $/kg	Alt_7-A	Alt_7-B +new turbines	Alt_7-C +fish screens	Alt_7-D +new turbines +screens
1	baseline assumptions	**95%**	**1.5**	**19%**	**8%**	**10%**	**6%**
2	switching values	95%	1.0	44.7%	32.0%	2.7%	-10.3%
3		95%	1.5	29.7%	21.3%	1.8%	-6.9%
4		95%	2.0	22.3%	16.0%	1.3%	-5.1%
5		95%	2.5	17.8%	12.8%	1.1%	-4.1%
6		95%	3.0	14.8%	10.7%	0.9%	0.0%
	baseline assumptions	**80%**	**1.5**	45%	23%	37%	21%
	switching values	80%	1.0	44.7%	32.0%	2.7%	-10.3%
		80%	1.5	29.7%	21.3%	1.8%	-6.9%
		80%	2.0	22.3%	16.0%	1.3%	-5.1%
		80%	2.5	17.8%	12.8%	1.1%	-4.1%
		80%	3.0	14.8%	10.7%	0.9%	-3.4%
	baseline assumptions	**60%**	**1.5**	81%	45%	72%	45%
	switching values	60%	1.0	44.7%	32.0%	2.7%	-10.3%
		60%	1.5	29.7%	21.3%	1.8%	-6.9%
		60%	2.0	22.3%	16.0%	1.3%	-5.1%
		60%	2.5	17.8%	12.8%	1.1%	-4.1%
		60%	3.0	14.8%	10.7%	0.9%	-3.4%
	baseline assumptions	**40%**	**1.5**	100%	90.0%	80.0%	50.0%
	switching values	**40%**	1.0	44.7%	32.0%	2.7%	-10.3%
		40%	1.5	29.7%	21.3%	1.8%	-6.9%
		40%	2.0	22.3%	16.0%	1.3%	-5.1%
		40%	2.5	17.8%	12.8%	1.1%	-4.1%
		40%	3.0	14.8%	10.7%	0.9%	-3.4%

Values in yellow indicate MSY loss values that are *lower* than the baseline assumption. For example, at US$3.00/kg and 95% passage, the MSY loss would need to be less than 14.8% to achieve a net benefit, so a lower loss than the baseline of 19.4%. On the other hand, at US$1.5/kg, the MSY loss at 95% could be as high as 29.7% and still achieve a net benefit.

Cells in red indicate values that are virtually impossible to achieve in practice. For example, if upstream passage is 80%, it will be difficult to achieve a total MSY loss of just 2.7% (even at US$1.0/kg fish value). Negative and zero values may be correct as a matter of arithmetic, but obviously not achievable.

At 40 % upstream passage, corresponding to the average international experience reported by Noonan, the modelling for Sambor Alt_7-A indicates collapse of the fishery (i.e. MSY loss of 100%). The baseline assumptions for the mitigation options at this low level of upstream passage are subject to even greater uncertainty than for the higher passage values, since reliable modeling results are still pending. However, at 40% upstream passage it is highly unlikely that one can achieve significantly lower MSY loss less than 40%.

Conclusions

This allows several important conclusions:

- Sambor Alt_7-C and Sambor Alt_7-D, which involve the addition of fish screens, are unlikely to be economic, *even if 95% passage rates were achieved* – the additional US$1 billion in capital cost of fish screens is not justified. The required average rates of MSY loss of less than 5 % are most unlikely to be achieved. Further study should therefore be focused on the application of low impact turbines (i.e. on Alt_7-B). Discussions with Alden, whose low impact turbines are at an advanced stage of design, are ongoing, and will be reported in the final report of the study in December 2017.
- Even at the conservative values assumed for the incremental costs of Alden turbines, the aggregate mortality could be as high as 21% to achieve a positive result for Alt_7-B at 80% upstream passage. Given preliminary indications from Alden of fish survival rates of 97-100% for five North American species across wide ranges of sizes, compared to comparable survival rates for Kaplan and Francis turbines of less than 85%, the prospects for this technology are promising.
- At high fish valuations, net benefits cannot be reasonably achieved if 95% upstream passage is not achieved. Unfortunately, this upstream passage success rate cannot itself be modeled – only once the project is built can we be certain of performance – and the worldwide experience is that passage rates of even more than 60% are rare.
- At 40% upstream passage, even at low fish valuations, it is most unlikely that any of the mitigation options can stave off collapse – though it is true that this does not take into account possible adaptations (such as finding new spawning grounds). As noted previously, the risk is that this can only be determined once the dam is built, at which point the damage may be irreversible.

More importantly, the encouraging results for fish-friendly turbines are subject to two *caveats*: first, that these turbines have yet to be demonstrated at commercial scale, which makes it very unlikely that an Independent Power Producer (IPP) would use this technology until that demonstration occurs. *This constitutes a further reason for RGC not to make a premature decision to commit to a hydro project at Sambor.*

Secondly, the main shortcoming of the switching values analysis is that all other variables are assumed to be unchanged. However, given so many variable subject to high uncertainty as shown in Table 12-2, this analysis has its own shortcomings. Indeed, even if the modeling of downstream passage provided reliable results on MSY loss with limited range of uncertainty, the calculation of net *economic* benefits is still subject to high uncertainty (given other uncertainties in LNG prices, the incremental costs and efficiency penalties of alternative mitigation measures, and the valuation of fish).

Probabilistic Assessment of the Hydro Options

Wide ranges in input assumptions result in wide ranges of estimates of net economic benefits. Ideally, if all the input assumptions subject to uncertainty were defined as probability distributions, one could then run the economic analysis many times to generate a probability distribution of net economic benefits, which then allows a judgment about the probability of achieving the development objective.

This approach to risk assessment is known as Monte Carlo simulation. This is a useful approach where indeed the definition of probability distributions has an empirical basis: such as hydrology variations around the mean, or the world-wide experience with dam construction costs.

However, the many variables involved in the Sambor Alternatives Assessment defy such definition. As noted in Chapter 11, the track record of forecasting future LNG prices is poor: who can reasonably define a probability distribution for the LNG price in 2030? Many of the variables required for the calculation of fish damage costs are similarly without empirical experience or evidence – as discussed above, the proportion of fish that spawn below Sambor is simply unknown, and could take on almost any value between 10 and 90%.

In such situations experts will often disagree on what is the most likely value, and "baseline" calculations will be contested on either side of the chosen value. However, while experts may disagree strongly over the most *likely* value, agreement on the plausible range of uncertainty may be more easily found. This leads to a modification of the usual Monte Carlo approach, in which one makes *no* assumptions at all about the probability distribution within an agreed plausible range of uncertainty. In some cases, this range is intrinsically bounded: the upstream passage success assumption cannot lie outside the range of 0 and 1.0. In effect, one runs a Monte Carlo simulation with uniform distributions for all variables – in other words, across the entire universe of potential futures (or at least a random sample of several thousand of these futures).

Table 12-4 shows a list of assumptions that are likely to have a significant impact on fishery damage costs and the net economic benefits. For each we show the value selected for the baseline, and a high and a low value around this which shows a plausible range of variation. For example, we have taken as a baseline the latest estimate of the MRC for the total size of the Lower Mekong Basin (LMB) fishery: A plausible range of uncertainty would include at least the range of values reported in the literature (recall Table 11-18).

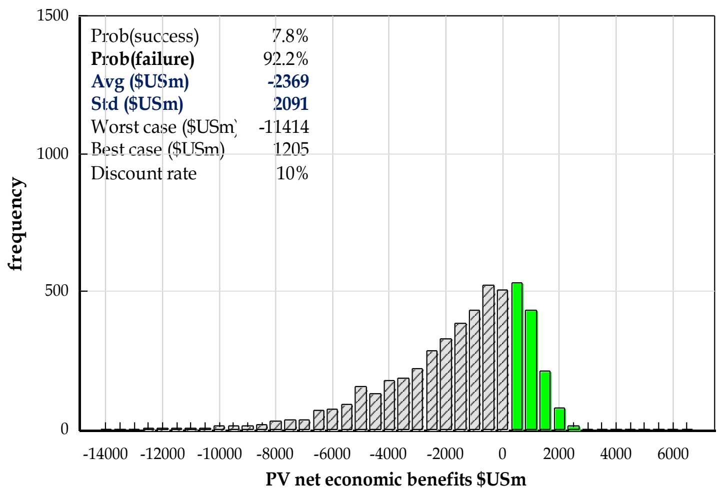
Table 12-4. Plausible ranges of uncertainty.

		low	Baseline	high
1 LNG cif Japan	$/mmBTU	7	10.0	12
2 FSRU tolling fee	$/mmBTU	0.8	1.0	1.5
3 LNG-CCGT capital cost	$/kW	925	800	1100
4 Fish yield	Mtpy	1,000,000	1,200,000	1,500,000
5 Migratory fraction	[ ]	0.28	0.38	0.48
6 Spawn below Sambor	[ ]	0.1	0.30	0.9
7 Upstream passage success	[ ]	0.4	0.80	0.95

			low	Baseline	high
8	7A MSY impact	[ ]	0.2	0.45	0.8
9	7B MSY impact	[ ]	0.1	0.23	0.6
10	7C MSY impact	[ ]	0.1	0.37	0.6
11	7D MSY impact	[ ]	0.05	0.21	0.3
12	Fish value	$/kg	0.5	1.5	3.5
13	Capital cost of 7A	$/kW	2000	2125	2200
14	Incremental capital cost of fish friendly turbine (as % of Kaplan turbine cost)	[ ]	10%	15%	30%
15	Efficiency penalty of fish friendly turbine	[ ]	5%	15%	20%
16	R&R cost per person	$	3500	10000	15000
17	Incremental fish screen cost	USm	800	1000	1200

The results of this simulation are shown in Figure 12-1. When one looks at all possible futures, without any prior judgement about the shape of the probability distributions, the chances of a successful project – i.e. one in which the net economic benefits are greater than zero – is very small, less than 1 in 10. Even with the successful development of new fish friendly turbines, there is only a one in four chance of a successful project.

Sambor Alt_7-A



Sambor Alt_7-B

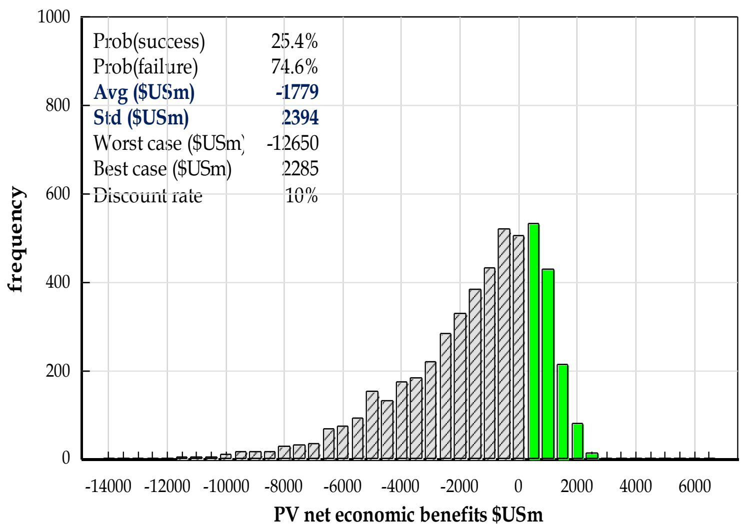


Figure 12-1. Probability distributions of the present value of net economic benefits for Alt_7-A (top image) and Alt_7-B (bottom image).

However, even successful mitigation and a project with net economic benefits does not resolve the question of whether RGC is willing to accept a significant fishery impact.

Risk Assessment of Solar PV

The risks of a solar PV project are far smaller than for large hydro projects:

- For all major risk categories, those of solar PV are more easily mitigated, and with predictable performance, and benefiting from dramatic future cost reductions.
- There is no comparable set of concerns as arise from dam safety and catastrophic accidents: the worst that can happen at a floating PV project is that the panels sink: the worst that can happen at a major hydro project is catastrophic powerhouse flooding or dam breaks. Perhaps the former is more likely than the latter, but the outcome of any failure is not comparable.
- The financial risks are smaller: construction times are very short, and not subject to delays attributable to geotechnical and construction risk. It is highly unlikely that a developer would need to raise additional financing during construction – not at all uncommon at hydro projects.

Table 12-5 presents a detailed risk comparison of Solar PV with a large hydro project on the Mekong mainstream.

Table 12-5. Risk comparison.

	Nature of risk	LMB Mainstream Hydro	Floating PV (at LSS2)
Weather (1)			
Droughts		Low (6)	None (may in fact be beneficial if cloud cover reduced)
Inter-annual resource variability	Analysis in Chapter 11 illustrates high variability of LSS2 inflows.	Medium (5)	Low (natural variation in insolation likely no more than ± 10%)
Extreme weather events			
Typhoon-related	High wind speeds if typhoon tracks enter Cambodia (see Box 11-1)	None	~~High~~ Some risk, but sound engineering practice to prevent wave and wind damage can mitigate
Accidents			
Operational	Powerhouse flooding due to equipment failures is the most common severe accident at hydro projects (though rare)	Very low	None (no moving parts, failure in panels or inverters do not have catastrophic impacts)
Geotechnical risks			
Earthquake		Very low (7), mitigated by safety factors in construction	None
Ground conditions	Unfavorable ground conditions are the most common cause of increased construction costs and construction delays	Medium (2)	None

	Nature of risk	LMB Mainstream Hydro	Floating PV (at LSS2)
Transmission related risks			
System stability		None	Low (can be mitigated by battery storage and reactive compensation)
Environmental risks			
Fishery damage	See Chapter 8	High	None
Sediment related impacts	See Chapter 4 and Chapter 6	High	None
Risks associated with inundation	Loss of forest, loss of biodiversity	Low (4)	None
Risks to downstream livelihoods	Impacts due to rapid changes in downstream water levels, impact on riverbank uses.	High	None
Hazardous materials		None	Low (arise only if battery storage is required, for which disposal requires careful management)
Decommissioning		Low	None (removing panels and simple floating structures has low risk)
Climate change risks			
Changes to inflow hydrology	Most likely is intensification of storms, leading to higher spill volumes in run-of-river or daily peaking projects	Low (3) (and long term)	None

Notes

(1) Climate change will of course affect weather in the longer term. However, droughts and inter-annual variability will occur even in the short term, and even in the absence of climate change impacts.

(2) Low only in the particular case of projects in Cambodia where indications do not suggest high likelihood of geotechnical problems.

(3) In the case of the LMB not affected by glaciers and snowmelt. The risks are much higher in the Himalayan projects. In Peru, hydro project inflows have increased in the short term due to higher than expected rates of glacier melting – but once depleted, inflows will be significantly diminished.

(4) Much of the area to be inundated at Sambor is has sparse forest cover.

(5) It is possible that large volumes of storage upstream of LSS2, or upstream of any hydro project at Sambor, will reduce the variability of inflows. This has been observed at Sambor (due mainly to projects in China), but not yet evident in the LSS2 inflows. The inflow average at LSS2 (49 years of historical inflows) is 1384 MCM, with standard deviation of 254 MCM, so the coefficient of variation is 18%.

(6) Figure 10-35 shows that (at least in the historical record) very few very low inflow years are followed by a second or third year that also has very low inflows. However, there is some evidence that the filling of the huge reservoirs on the Lancang in China has exacerbated low flow conditions in recent years: but filling inactive storage upstream is a one-time event.

(7) In comparison with projects in the Andes and Himalayas and more geologically active areas.

Commercial Readiness

A significant question for solar PV augmentation is the commercial readiness of the technology. This is no issue for large hydro, for which the commercial readiness of conventional turbines is unquestioned, for which manufacturer's warranties for performance and generally accepted (and procedures for calculating liquidated damages in the event of non-performance). A private investor in large hydro has few concerns in this respect, the risks in this regard being far lower than geotechnical or hydrology risk.

With some 21,000 MW of Solar PV now installed worldwide, solar PV technology has evolved to the point at which it is generally accepted worldwide, and very large scale projects are now routine (such as the 650 MW facility completed in late 2016 at Kamuthi, in India). PV modules are now manufactured to the point at which warranties can extend to 20 years. Moreover, it is worth noting that while a hydro turbine-generator is a highly complex device with moving and delicate parts that require careful monitoring and rigorous maintenance, solar panels, once installed, are quite robust. To be sure, there are operational risks that emerge over time that require attention (as noted in Chapter 10), but the mitigation measures (such as regular cleaning) pose few problems in practice. These are really no different in scope and importance than routine measures at hydro projects (such trash rack cleaning).

The one component of a PV project that is likely to have shorter working life than the panels themselves are the inverters, which may require periodic replacement. But again, as discussed in Chapter 10, inverter costs are falling and warranties are getting longer. Indeed, in principle this is no different to major maintenance issues at large hydro projects (e.g., runner blade replacement due to blade erosion). Lenders' imposition of a major maintenance reserve account for inverter replacement would be no different to those required at large hydro projects.

The major question for our proposal for PV augmentation at Lower Sesan 2 (LSS2) is really about the floatation methodology. Experience with this is admittedly much more limited. However, this is about well understood mechanical engineering, and the very rapid growth in floating PV projects worldwide (again as noted in Chapter 10) is testimony to the fact that what constitutes a reliable design is now well understood by vendors of such systems.

In any event, a developer does not have to commit to the entire ultimate scale of project on day one – PV is easily modularized, so an initial 25-50 MW commitment in any event has low risk – unlike the up-front commitment for 1,000 MW of a large hydro project. Any operational problems can be sorted out at small scale, before commitments are made for additional tranches: indeed, with costs of all components of PV project expected to fall, phased development is in any event desirable.

Financial Risk

The modularity and lack of scale economy of PV projects results in a significantly lower degree of financial risk compared to a 2,600 MW scale project at Sambor.

First, we note the role of interest during construction(IDC). Typically, comparisons of capital costs are made on the basis of so-called overnight costs, so Sambor at US$1,984 per KW, Solar PV at around US$1,000/kW.[117] But Sambor takes at least six years to build, adding an additional 20-25% of costs due to interest during construction. A PV project can be built in less than a year, so IDC may be a few percent, at most. Thus, the real cost of Sambor is around US$2,550/kW, while solar PV is around US$1,050/kW.

[117] See Table 11-1.

Second, a solar PV project could be built in tranches of 50-100 MW: so the investment for the first 50 MW of PV will be around US$50 million. At 70:30 Debt: equity ratio, that means at financial closure some US$35million of debt needs to be mobilized. Sambor at 2,600 MW requires total debt finance (including capitalized IDC) of US$4.6 *billion*. US$35 million is easily mobilized from a single source; US$4.6 *billion* requires significant syndication. Indeed, with a construction time of less than one year, finance for a second 50 MW PV project (given a very low probability of construction delay) makes raising a second tranche relatively easy, as revenues begin to flow almost immediately.

Whether large or small, projects promoted by IPPs require a bankable Power Purchase Agreement (PPA) to get to financial closure. And what makes for a bankable PPA is mainly the creditworthiness of the off-taker, bolstered if need be by sovereign guarantees – as was required for LSS2. Signing a 20 year PPA for a 11,000 GWh per year implies a commitment of the buyer of US$880 million per year (assuming an 8USc/kWh tariff). Almost certainly this would require an RGC guarantee. A 20 year PPA for a 50 MW PV project implies revenue to be guaranteed for only around 80 GWh per year, or US$6.4 million. To be sure each tranche would require the same again, but instead of six years of no revenue with a large hydro project, revenue flows within a year of the start of construction. In short, the risk exposure of PV is lower because:

- Mobilizing debt finance in small tranches is much easier than for multi-billion dollar projects,
- Very small risk of construction delays due to environmental and NGO opposition to hydro, so revenue flows within a year after construction start,
- Much smaller requirement for Government guarantees,
- Deemed generation provisions in PPA unnecessary because more easily matched to load growth of the off-taker,
- Financial closure much easier to secure to a predictable timetable.

None of this means that PPA negotiations will necessarily be easy, given likely concerns of the Electricity of Cambodia (EdC) about intermittency issues. But, whatever may be the difficulties, they pale into insignificance when compared to those of a multi-billion dollar hydro project. To get the environmental clearances, negotiate a PPA, prepare bidding documents, and mobilize the finance would take at least three years; with another six years for construction, that means that even if the RGC committed to Sambor in 2018, construction could unlikely begin before 2021-2022, so 2027-2028 is the earliest conceivable date of commissioning.

Whether Sambor could be built for export to Vietnam or Thailand is indeed worth consideration. The Electricity of Vietnam (EVN) will likely obtain a commercial credit rating in 2018, but is a long way from being seen as commercially creditworthy for a private 2,600 MW-scale project: and the appetite of the Government of Vietnam for extending guarantees of the type offered by RGC to LSS2 sufficient for a 20-year PPA seems most unlikely. The Electricity and Gas Authority of Thailand (EGAT) may be more creditworthy, with strong domestic banks willing to lend to EGAT projects (as at Xayaburi), but what would be their interest in Sambor is unknown. Private investors would see such a project as relatively high-risk, with correspondingly higher required equity returns. With International Finance Institutions (IFIs) and concessional financing not available to a large mainstream project in the LMB, interest rates will be high.

In short, the level of financial risk for Sambor is extremely high; the level of risk for a multi-tranche solar PV augmentation project at LSS2 is much smaller and more easily mitigated.

Mitigation risk

Finally, there exists an additional level of risk associated with the mitigation of the various technical risks identified in Table 12-5. As noted, we have proposed a number of mitigation measures for a Sambor dam that will mitigate the fishery damage costs of a mainstream hydro project. But, there remains significant uncertainty about the effectiveness of these measures; while we have proposed design principles for upstream fish passage, based on international best practice, the fishery in the Mekong is unique in its diversity, and we cannot have great certainty in their effectiveness.

This is in contrast to the mitigation measures that apply to solar PV. The technical performance of battery storage, of modern reactive compensation devices, of flywheels, are all predictable with reasonable certainty, and the only significant uncertainty is the rate at which their costs will *decrease*. It is true that EdC must be convinced that the intermittent nature of PV can be mitigated by a combination of hydro ramping flexibility and storage options, but here the international experience provides considerable comfort: unlike the unique nature of the Mekong fishery, the problems faced by EdC have been successfully solved by technical interventions by large numbers of other utilities – for example, in many small African countries solar PV has been successfully integrated. These same solution approaches are directly applicable to the Cambodian experience – quite different to the difficulties of extrapolating fishery impacts from one country to another.

Conclusion

All of the Sambor dam alternatives have a high risk of providing a negative net benefit under the current state of knowledge. The prudent course is to defer a decision until these uncertainties can be narrowed.

This report demonstrates that the no-dam alternative of floating PV at LSS2 is by far the best renewable energy option, and should move quickly to a more detailed feasibility study. Even when integration costs are included, the likely generation price is comparable to that of hydro projects, and considerably below the cost of a hydro project that incorporates the best available fishery damage and sediment management mitigation (such as Alt 7-A). The PV alternative may have some small level of technology risk, but this is far outweighed by the complete absence of environmental damage risks,

Clearly, while we have demonstrated the proof-of-concept, we have not had access to the necessary detailed technical information of the project at LSS2 that permit definitive conclusions about its feasibility: additional information (particularly on ramp rates and the technical characteristics of the generators) will be necessary to confirm the technical and financial feasibility. Nevertheless, the following is worth noting:

- A 400 MW scale solar PV project can be implemented at LSS2 without any risk of disrupting ongoing hydro operations.

- A first phase of 50 MW – 100 MW could easily serve as a pilot before making commitments to the remaining 300-350 MW, without loss of economic benefits (very easy to add additional modules without loss of any economies of scale).
- Compared to any project at Sambor, such a project could easily be implemented by 2019: the environmental clearances would be routine and unlikely to delay implementation.
- To achieve the necessary benefits of hydro-PV integration, the augmentation project can *only* be undertaken by the existing operator at LSS2: a different owner/operator for the PV component at LSS2 would be contractually and technically impossible.
- A solar PV project at LSS2 does not foreclose a Sambor hydro project or a Sambor hydro/solar hybrid project: however, the LSS2 PV project is clearly the better option for meeting the next increment of demand for power consumption of export as it avoids the considerable risks, public controversy, and the strong opposition of Vietnam. Moreover, deferral of a decision on Sambor allows further time to resolve the uncertainties about fishery damage costs: once LSS2 and Xayaburi are both in operation the extent of fishery damage at these projects can be confirmed. The longer a Sambor dam is deferred, the less financially attractive it is likely to be compared to solar PV alternatives with their steadily declining costs. Indeed, there may never come a time in the future when a Sambor dam is the next least-cost option for Cambodia in strictly financial terms; more certainly, it will never be the best next option when the natural resource costs are taken into account.
- If RGC were to make a decision to build a project at Sambor, this report provides the design principles that should be followed to minimize the environmental impacts (fish friendly turbines, extensive fish passage facilities, engineering and reservoir designs to maximize flow velocities in the reservoir and allow effective sediment flushing practices).