VOLUME 3
Floating Solar PV Alternative

SUSTAINABLE HYDROPOWER MASTER PLAN FOR THE XE KONG BASIN IN LAO PDR

FINAL REPORT

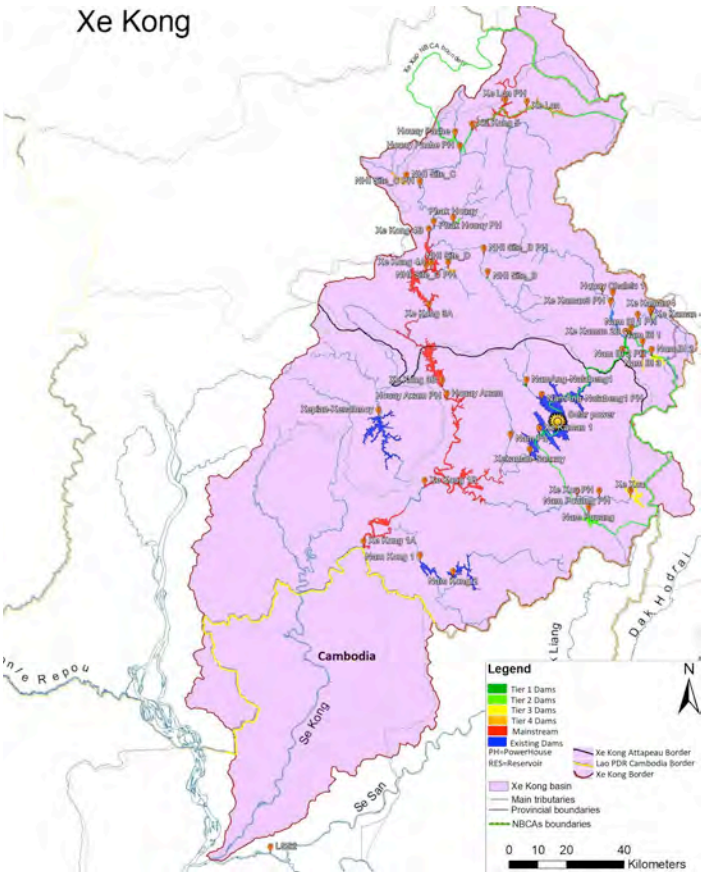
A component of

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

Submitted to
Government of Lao PDR

Submitted by
Natural Heritage Institute, San Francisco, California
In Association with the National University of Lao

January 2018



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Sustainable Hydropower Master Plan for the Xe Kong Basin in Lao PDR

Final Report

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Supported with Funding from:

The United States Agency for International Development

The MacArthur Foundation

The Margaret A. Cargill Foundation

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Acronyms

3S	Xe Kong, Se San and Sre Pok Rivers, known collectively as the "3S" rivers
ADB	Asian Development Bank
AIT	Asian Institute of Technology
ASEAN	Association of Southeast Asia Nations
BOO	Build-Operate-Own projects
BOS	Balance of System
BOT	Build-Operate Transfer projects
CA	Concession Agreement
CAPEX	Capital Expenditure (or upfront capital expenditure)
CFD	Computational Fluid Dynamics
CIA	Cumulative Impact Assessment
CIAGs	Cumulative Impact Assessment Guidelines
CIP	Committee for Investment Promotion and Management
CIR	Capacity Inflow Ratio
COD	Commercial Operation Date
CPU	Catch Per Unit
CPUE	Catch Per Unit Effort
DEB	Department of Energy Business
DEPP	Department of Energy Policy and Planning
DNEI	Department of Natural Resources and Environment Inspection
DNREP	Department of Natural Resources and Environmental Policy
DWR	Department of Water Resources
ECAFE	Economic Commission for Asia and the Far East
ECC	Environmental Compliance Certificate
EDL	Électricité du Laos
EIA	Environmental Impact Assessment
EMDP	Ethnic Minority Development Plan
EMMP	Environmental Management and Monitoring Plan
EPA	Environmental Protection Agency of the United States
EPC	Engineering Procurement and Construction
EPCI	Equity Project Cost Investment
EPRI	Electric Power Research Institute (of the US)
ESIA	Environmental and Social Impact Assessment
ESMMP	Environmental and Social Management and Monitoring Plan

EVN	Électricité du Vietnam; and same acronym refers to energy demand curve
FI	Flood Index
FS	Feasibility Study
FTCC	Floating Tracking Cooling Concentrator
GHI	Global Horizontal Irradiance
GL	Gigaliters
GMS	Greater Mekong System
GoL	Government of Lao PDR
GWh	Gigawatt hours
GWh/y	Gigawatt hours per year
HIA	Health Impact Assessment
HPD	Hydropower Development
HSAP	Hydropower Sustainability Assessment Protocol (of IHA)
HWL	High Water Level
IADB	Inter-American Development Bank
IC	Insurance Cost
IDC	Interest During Construction
IEE	Initial Environmental Examination
IEI	Inverter Warranty Extension Investment
IFC	International Finance Corporation
IFI	International Finance Institutions
IFReDI	Inland Fisheries Research and Development Institute
IHA	International Hydropower Association
IMC	Inter-Ministerial Committee
IP	Ingress Protection
IP65	International classification for the ingress protection
IPP	Independent Power Producer
IRD	Irradiance
IRENA	International Renewable Energy Agency
ITRPV	International Technology Roadmap of Photovoltaic
JICA	Japanese International Development Agency
JMA	Japan Meteorological Agency
Km	Kilometers
kPA	Kilopascal, a unit of pressure
kWac	kilowatt AC power
kWp	Kilowatt peak (peak power)

LAC	Limits of Acceptable Change
LAK	Lao Kip (currency of Lao PDR)
LCOE	Levelised Cost of Electricity
LEK	Local Ecological Knowledge
LEPTS	Lao Electrical Power Technical Standards
LMB	Lower Mekong Basin
LMS	Lower Migratory System
LSS2	Lower Se San 2
LTCR	Long-Term Capacity Ratio
m	Meters
m^3/s	Meters per second
mill m^3	Million meters cubed (for total reservoir volume)
MAF	Ministry of Agriculture and Forestry
MDS	Multi-Dimensional Scaling
MEM	Ministry of Energy and Mines
MIGA	Multilateral Investment Guarantee Agency
MMS	Middle Migratory System
MoNRE	Ministry of Natural Resources and Environment
MoF	Ministry of Finance
MOU	Memorandum of Understanding
MPI	Ministry of Planning and Investment
MR	Mutilation Ratio (a component of a blade strike model)
MRF	Multiple Reference Frame
MRC	Mekong River Commission
MRCS	Mekong River Commission Secretariat
MSSS	Maximum Sustainable Swimming Speed
MTBF	Mean Time Between Failures
Mt/yr	Metric ton per year
MW	Megawatts
MWac	Megawatt AC power
MWp	Megawatt peak
NBCA	National Biodiversity Conservation Areas
NDR	Nominal Discount Rate
NHI	Natural Heritage Institute
NTEC	Nam Theun 2 Electricity Consortium
NTFPs	Non-Timber Forest Products

NUoL	National University of Lao
OAAs	Other Aquatic Animals
O&M	Operation & Management/ Operating & Maintenance Cost
PAPs	Project-Affected Persons
PDA	Project Development Agreement
PDEM	Provincial Department of Energy and Mines
PDPI	Provincial Department of Planning and Investment
PDPVII	The Power Development Plan VII
PID-free	The PV module is free from Potential-Induced Degradation
PPA	Power Purchasing Agreement
PPP	Public-Private Partnerships
PR	Performance Ratio
PSHD	Policy on Sustainable Hydropower Development in Lao PDR
PV	Photo Voltaic
RAP	Resettlement Action Plan
RC	Resettlement Committee
rpm	revolutions per minute
RSCP	River System Coordination Plan
R&R	Resettlement and Relocation
SDR	System Degradation Rate
SERIS	Solar Energy Research Institute of Singapore
SESO	The Standard Environmental and Social Obligations
SHA	Shareholder Agreement
SIA	Social Impact Assessment
SOP	Social Action Plan
SR	Scoping Report
SSY	Suspended Sediment Yield
ST	Stung Treng monitoring site
SWAT	Soil and Water Assessment Tool
TbEIA	Transboundary Environmental and Social Impact Assessment
TF	Total Flow
ToR	Terms of Reference
TP	Tax Payment
NT2	Nam Theun 2
TWL	Tail Water Levels
UN	United Nations

UPS	Upper Migratory System
WATT	Weighted Average Cost of Capital
W/m	Watts per cubic meter, such as the measurement for Turbulence
Wp	Watt-peak
XK1	Xe Kaman 1 Hydropower project

EXECUTIVE SUMMARY

The past few years have seen a dramatic reduction in cost of solar photovoltaic power generation (Solar PV) which therefore presents a renewable energy enhancement to existing hydropower facilities in the Xe Kong Basin that would avoid the high environmental damage costs of building new hydro projects on the mainstream instead.

Because solar panels only produce power when the sun shines, and even then, rapid changes in output occur when clouds pass over, integration of the output into a power grid can be problematic at large scale (100 MW and more). One way of addressing these integration problems is to combine a solar PV project with a hydro project. The flexibility of power output from hydro turbines allows the hydro project to function as a large battery, allowing the combined project to deliver into the grid smoothed and dispatchable power. 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. When water storage is possible, it also allows high-value hydropower to be produced at peak demand time.

Two other advantages of installing solar PV at an existing hydropower reservoir are:

(1) the benefit of using existing electrical infrastructure, including high voltage grid access and transformation devices. This drastically lowers the overall costs and allows projects to be deployed quickly.
(2) Avoiding the need to acquire large land areas and the need for resettlement and relocation of large numbers of persons.

For these reasons, the Master Plan examines the deployment of floating solar PV at the largest existing hydropower reservoir in the Xe Kong Basin, the Xe Kaman 1 hydro power project ("XK1"), as an additional electricity generation source. This project is owned and operated by the Viet-Lao Joint Stock Company (VLJSC) under a concession agreement with the Government of Lao. The project consists of the Xe Kaman 1 hydropower plant at the upper level and the lower level and the Xe Kaman Sanxay hydropower plant at the lower level with a total design capacity of 322 MW and a planned total output of 1.22 billion kWh per year. The lower reservoir can be operated as a re-regulation reservoir to counteract the large daily distortions in the downstream flow pattern that result from hydro-peaking operations that would be associated with hybrid operations with a solar component. This is important because these distortions can be quite detrimental to the fishery.

In general, during most months of the year (Dec to Aug), solar PV compliments well the hydro power generation. However, during the wet months, there is an oversupply of water and hydro facility is normally running at its peak capacity. Depending on the carrying capacity of the transmission line from Xe Kaman, the PV/Hydro hybrid generating facility could face curtailment during September to November.

The limitations on the scale of floating PV that could be installed on the Xe Kaman Reservoir are:

- The transmission evacuation capacity. The evacuation of the power from Xe Kaman 1 is through a 230 kV double-circuit transmission line to Pleiku 2 500kV substation in Vietnam, with a nominal capacity of 666 MW, which can be upgraded to 800 MW if required (e.g. in case the Floating Solar addition would go beyond the nominal line capacity). The load flow results show that the existing 230 kV line will experience constraints once the PV installation reaches 400 MWp. For a further PV capacity increase, it is recommended to upgrade the line capacity to 800 MWp. For any PV installation above 500 MWp, it is recommended to build new transmission lines for safe operation of the transmission lines.

- The ability of the EVN grid to absorb short-term fluctuations- though this can always be mitigated (at a cost) by storage batteries or flywheels. With Xe Kaman representing a small contribution to the very large installed capacity of Vietnam, the ability to make a few hundred MW of solar PV dispatchable may not be a significant constraint.

- Environmental limits – there would likely be limits as to how much of the surface area one can cover before there may arise questions regarding water quality, the eco-system, and the impact on any reservoir fisheries. But even coverage of only 10-15% of the total water surface area would in principle allow more than 1,000 MW

The maximum PV that can be made dispatchable by ramping down of hydro units is 217 MW, so about two thirds of the installed hydro capacity. A PV project with a first phase of 200 MW, followed by a second phase of another 200 MW should be the subject of a detailed feasibility study. Once the concept has been proven, and 400 MW absorbed by the EVN grid without difficulty, one may then examine the feasibility of additional tranches as may require transmission line upgrades or additional evacuation capacity (perhaps involving other hydro projects in Laos as well).

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. Such a project would be eligible for concessional financing, which greatly increases its financial viability. The modularity and short construction periods make this technology well suited to the uncertainties of load growth in Laos – 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. In the case of PV evacuated into the EVN system of Vietnam (as would be the case at Xe Kaman 1), the potential demand in Vietnam is so large that annual increments of 500 MW could easily be accommodated.

- 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 Francis turbines at XK1 cannot absorb short-term output fluctuations, reactive compensation and – as last resort - battery storage systems will be able to mitigate this impact at relatively small incremental cost.

- ~400 MWp of additional Floating PV can be accommodated on the existing 666 MW transmission line, which increases to almost ~500 MWp in case the line is upgraded to 800 MW.

- A floating PV system at XK1 can be added without in any way detracting the ongoing hydro operations. Given the strong interest of the present operator/owner of XK1, 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 XK1. However, engineering solutions are available to mitigate this risk.

11 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 transmission lines with limited capacity, this becomes a significant issue.

One way of addressing these integration problems is to combine 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. However, this mode of operation may create large daily distortions in the downstream flow pattern, that can be quite detrimental to the fishery and therefore requires mitigation whenever applicable.

The first such hybrid 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, were added to a 1,280 MW hydro project. This project is described in some detail in Appendix 11.1, 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 Laos, 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 PV.

For this reason, we have examined the possibility of floating solar PV at the existing Xe Kaman 1 hydro power project ("XK1"), as an additional electricity generation source (see Figure 11-1).

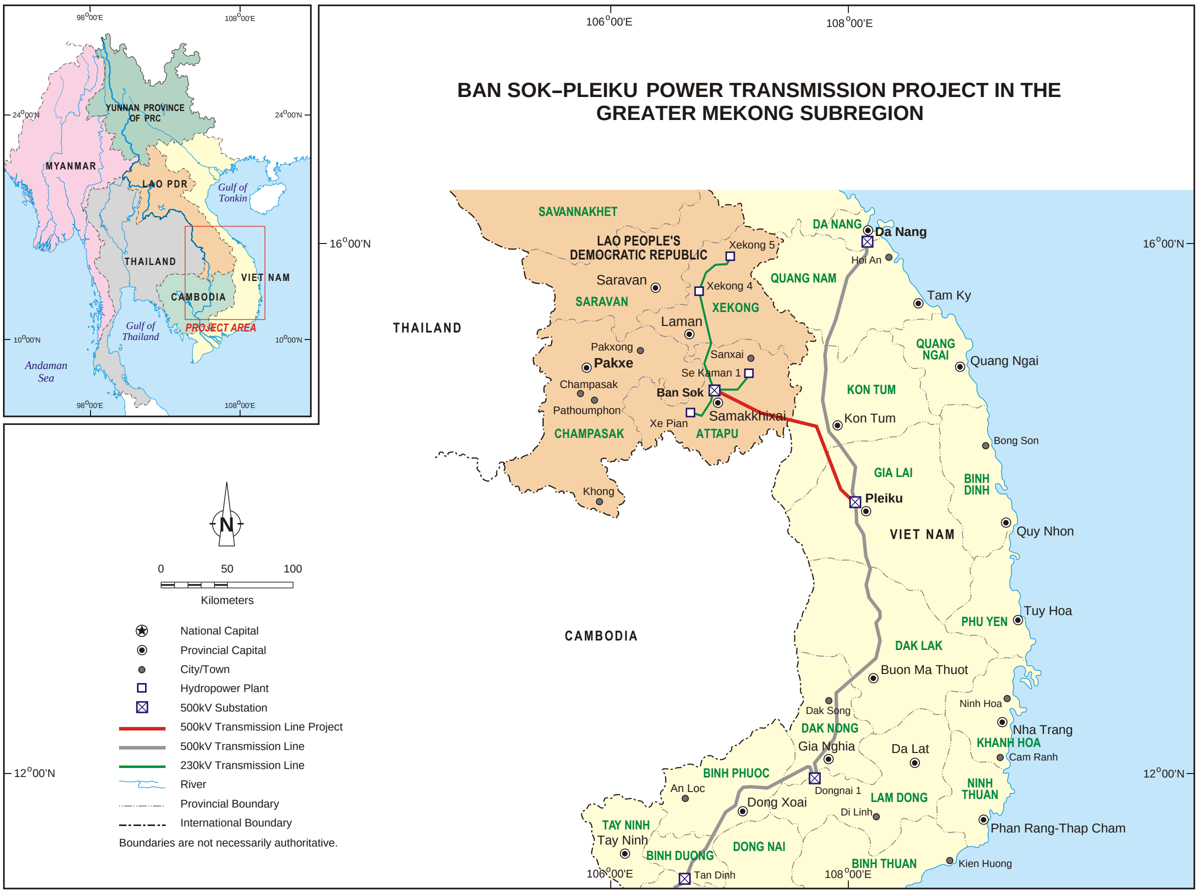


Figure 0-1. Location of the XK1 project and transmission line inter-connection to Vietnam (Source: ADB, 2008).

The Xe Kaman 1 Hydro Project

In 2008, the Government of Lao PDR and Viet-Lao Joint Stock Company (VLJSC) signed a Project Development Agreement (PDA) for the proposed Xe Kaman hydropower plant located, on the Xe Kaman River in Sanxay and Xayxettha districts of Attapeu province, about 40 km from the Laos-Vietnam border. The project would comprise at the upper level the Xe Kaman 1 hydropower plant, and at the lower level the Xe Kaman Sanxay hydropower plant, with a total design capacity of 322 MW and a planned total output of 1.22 billion kWh per year. For the operation, a joint venture was formed in 2010 between Viet-Lao Joint Stock Company and Electricite du Laos: Xe Kaman 1 Power Company Ltd. After signing the Commercial Agreement in February 2011, ground-breaking for Xe Kaman 1 took place a month later in March 2011. Five years later, commercial operation started in 2016.

Table 11-1 summarizes the important features of the Xe Kaman 1 hydropower development, as well as for the related Xe Kaman 3 project, including the respective transmission lines to Vietnam.

Table 0-1. The Xe Kaman 1 project.

#	Parameters	Unit	Xe Kaman 1	Xe Kaman Sanxay	Xe Kaman 3	Xe Kaman 1-Pleku 2 230kV Line	Xe Kaman 3-Thanh My 220kV Line
1	Total investment cost	Million USD	426.52	60.64	449	52.3	
2	Reservoir volume	Million m^3	4,800	8.65	141.49		
3	Useful volume	Million m^3	1,680	2.2	108.54		
4	Installation capacity	MW	290	36	250		
5	Max capacity of transmission line to Vietnam (in the absence of N-1 condition)	MW				800	550
6	Annual average output	Million kWh	1,096	123	1,006		
7	Power tariff on 25-year average expectedly applicable to EVN	UScent/kWh	6.4	6.4	6.50		
8	Annual average revenue	Million USD	60.77	6.82	65.39		
9	Lao Government's expected yearly average benefits from projects	Million USD	9.10	1.02	7.61		
10	Operation period		August 2016	June 2017	June 2013	August 2016	June 2013

Figure 11-2 and Figure 11-3 show the Xe Kaman 1 hydro dam and the switch yard where the transmission line to Pleiku 2 in Vietnam starts.

Figure 0-2. Xe Kaman 1: hydro power dam.

Figure 0-3. Xe Kaman 1: switch yard with transmission.

Transmission arrangements

The evacuation of the power from Xe Kaman 1 is through a 230 kV double-circuit transmission line to Pleiku 2 500kV substation in Vietnam, with a nominal capacity of 666 MW, which can be upgraded to 800 MW if required (e.g. in case the Floating Solar addition would go beyond the nominal line capacity). The 70.6 km section from Xe Kaman 1 to the Vietnamese border (USD 52.3 million investment) is owned and operated by Viet Lao Joint Stock Company, while the section between the border and Pleiku 2 is owned and operated by Electricity of Vietnam, EVN (USD 113 million investment).

Although under the terms of the agreement 20% of the power is due to Laos, all of the Xe Kaman 1 power is evacuated through the transmission line to Vietnam, and synchronized with the Vietnam Grid.[1] This share is then wheeled back into Laos through other inter-connections. However, the important technical point is that Xe Kaman 1 is connected to the relatively strong Vietnam Grid, not the weak grid of Laos.

There would doubtless need to be a similar provision for any additional solar power: the advantage to Laos being that any power received from the main EVN grid would be smoothed of any short-term fluctuations.

Implementation Issues

How would such an add-on be implemented? Since the whole point of the concept is to integrate closely the electrical systems and operational performance of the PV and hydro components, it would not be practical to bring in a new developer to implement a solar PV add-on.[2] In short, only if VLPJSC is interested in developing the additional floating PV project at Xe Kaman 1 would a detailed Feasibility Study (FS) be undertaken, and then implemented by VLPJSC.

[1] This is quite different to the arrangements at the Nam Theun 2 project, where the share of hydro power destined for Laos is generated in a separate power house (and penstock) that is synchronized with the Lao grid, as opposed to the main powerhouse and switchyard that is synchronized to the Thai grid.

[2] 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 VLPJSC.

Commercial Issues

The options on how a PPA to cover PV production 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. The current PPA provides for a reduced price (50%) for surplus energy (i.e. beyond the contractual minimum). As will be shown below, it seems unlikely that PV energy would be profitable at the reduced price: most likely it 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.

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 Xe Kaman switchyard.[3] There should be no problem providing check metering facilities to separate hydro and PV generation.

Financing issues

A solar PV add-on at any existing hydro project, including others in Laos, will depend crucially on the financing arrangements, since the tariff necessary to achieve an adequate return to the equity investors is directly related to the cost of debt finance. The most obvious approach to achieve a lower cost of debt is to secure concessional finance.

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:

- A project on an international river requires a written "no objection" certification of the downstream riparian. Whether this would be required for hydro projects in the Xe Kong river is unclear – in this case from the Government of Cambodia (though the ultimate downstream riparian would again be 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.

[3] It is true that one might hypothesize a completely separate entity to build, own and operate the floating PV add-on, with this entity selling power to VLPJSC. 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 VLPJSC because it 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.

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).[4]

It may be objected that any kind of IFI finance would require a sovereign guarantee. But 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 a 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 production plan of VLPJSC.

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 the hydro operator and the off-taker, 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.

[4] 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.

The Solar Resource of Laos

Solar energy potential in Laos is considered high, with an average of slightly over 5 kWh/m^2 per day (see Table 11-2 below) or equivalent to 1800-1900 kWh/m^2 per year (Figure 11-4) and average sunshine duration of 6–9 hours per day. Solar energy is estimated to have technical potential of 8,100MW and energy output of 14,781 GWh per year. According to EDC, solar energy can serve up to 5%–10% of total generation in the long run (GreenTech Media, 2017).

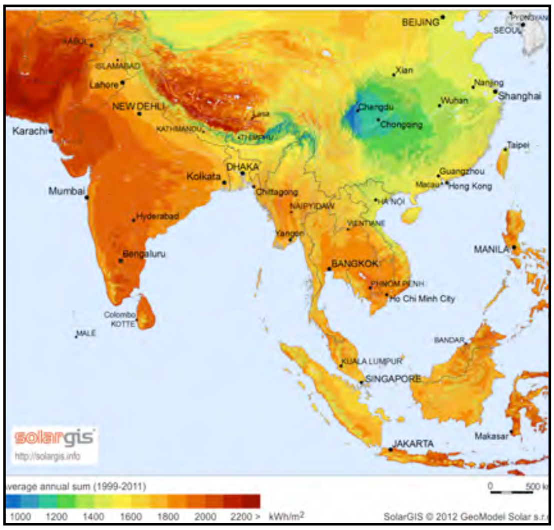


Figure 0-4. Solar resource map for Asia (Source: SolarGIS).

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. 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. There are limited sources of ground based meteorological stations in Laos (Figure 11-5). 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.

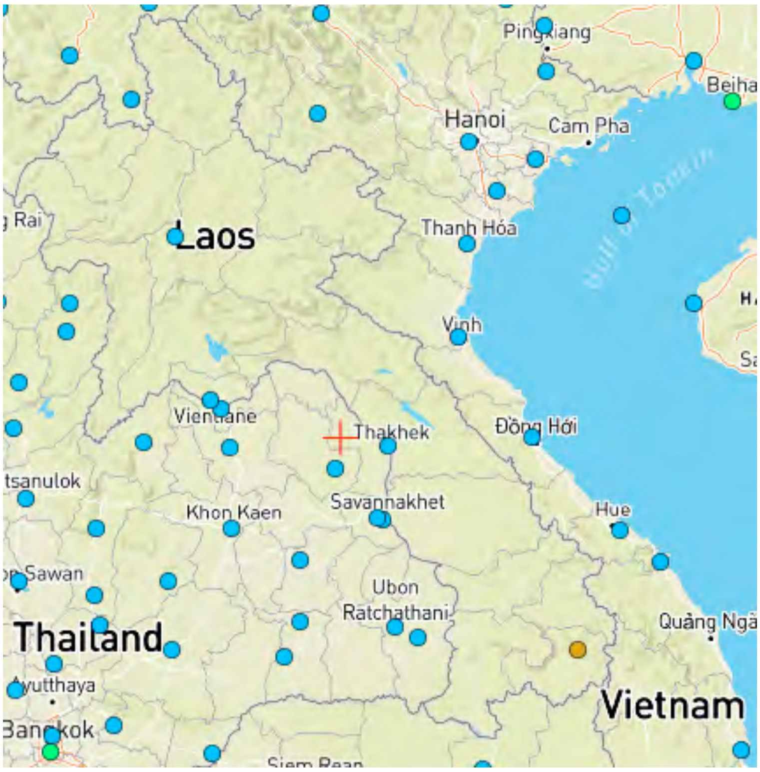


Figure 0-5. Map of Weather Stations in the region. Source: Renewables Now, 2017a.

There are free satellite databases available online, e.g. NASA (2016). In that study, monthly solar radiation maps of average daily global solar irradiation over Laos 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 0-2. Monthly global horizontal insolation, as extracted from NASA Surface meteorology and Solar Energy website (https://eosweb.larc.nasa.gov/sse/)

Monthly Averaged Insolation Incident On A Horizontal Surface (kWh/m²/day)													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
22-year Average	5.53	5.99	6.14	5.94	5.19	4.42	4.24	4.00	4.32	4.79	4.95	5.09	5.04
Minimum And Maximum Difference From Monthly Averaged Insolation (%)													
Minimum	-9	-15	-10	-14	-10	-15	-28	-24	-18	-18	-18	-10	
Maximum	4	9	10	12	16	16	22	27	15	17	16	11	

For this current study, solar potential and long-term climate data are obtained from commercial software Meteonorm (Version 7.1 http://www.meteonorm.com/; NASA, 2016), which combine satellite data and ground station data with interpolation, coupled with computational models to generate hourly radiation data[5]. These hourly time series can then be used for PV system yield

[5] 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 [16].

prediction as inputs. Such method provides more accurate estimation of solar resources, and becomes often the commonly used approach for solar resource assessment[6].

Figures 11-6 and 11-7 below show the obtained solar irradiance data at Xe Kaman project site. Other major meteorological parameters, such as ambient temperature, precipitation, are shown in Figure 11-8 and 11-9.

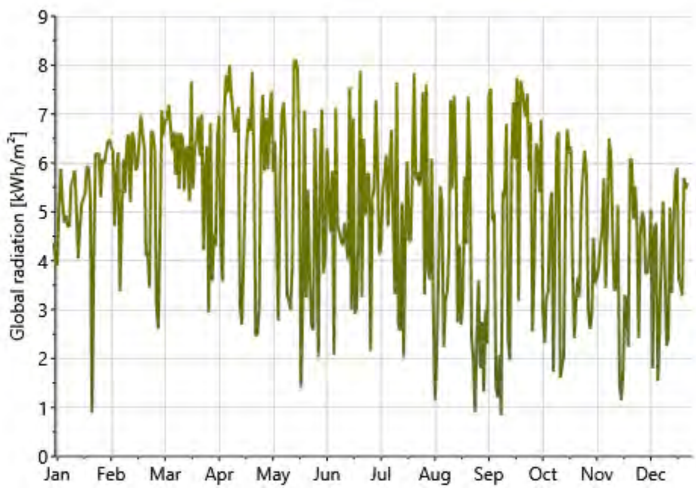
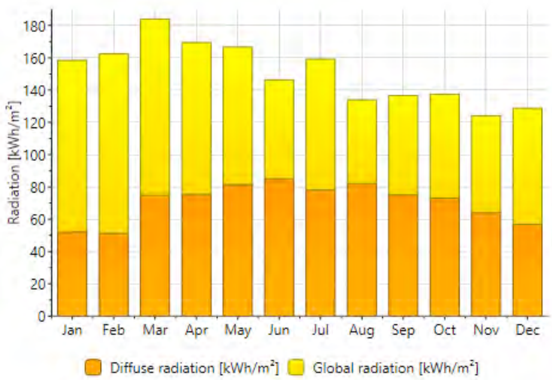


Figure 0-6. Daily Global Horizontal Irradiance [kWh/m2].



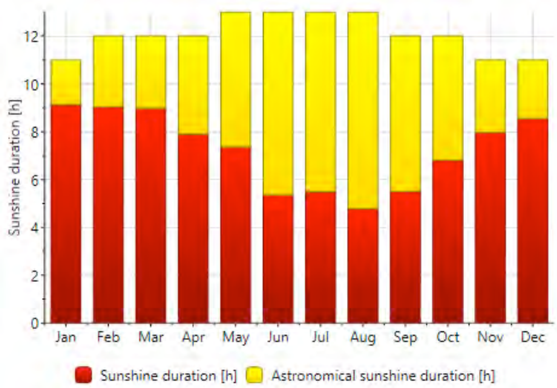


Figure 0-7. (Left chart) Monthly Global radiation and the diffuse component [kWh/m2]. Direct + Diffuse = Global radiation. (Right chart) Sunshine duration [hour].

[6] Alternative of such commercial software is SolarGIS: http://solargis.com/.

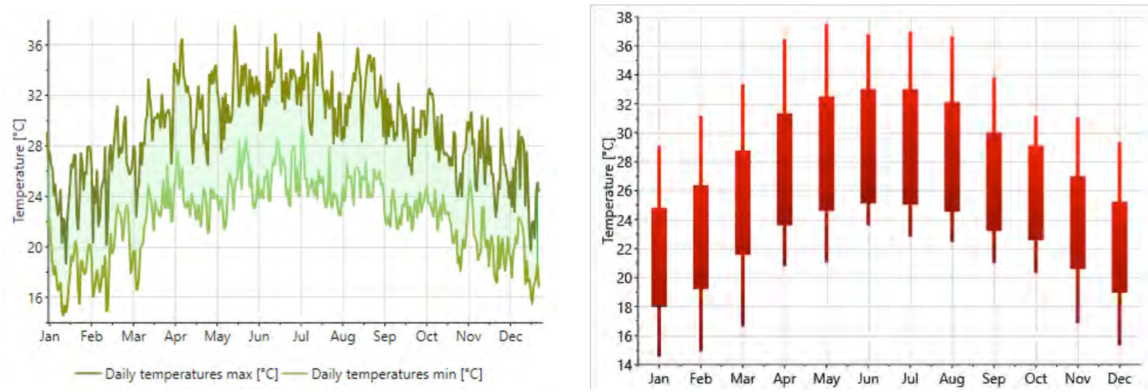


Figure 0-8. (Left) Daily ambient temperature range (min, max) [°C]. (Right) Monthly temperature ranges with quantiles [°C].

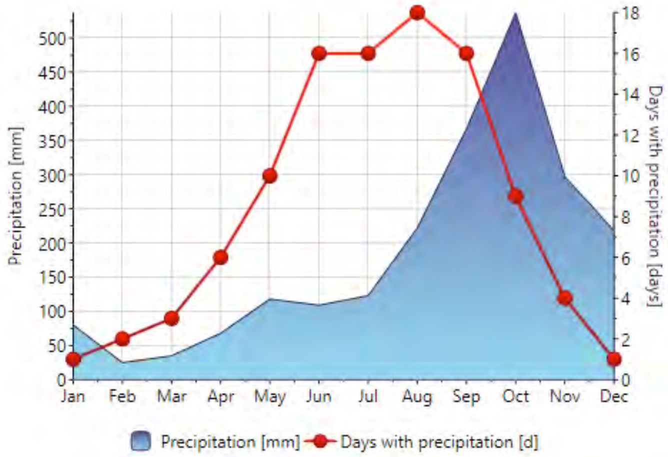


Figure 0-9. Monthly Precipitation [mm] and number of days with precipitation per month.

Under the Monsoon's influence, there are two typical seasons in Laos. 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 in Figure 11-9.

In general, during most months of the year (Dec to Aug), solar PV compliments well the hydro power generation. However, during the wet months, there is an oversupply of water and hydro facility is normally running at its peak capacity. Depending on the carrying capacity of the transmission line from Xe Kaman, the PV/Hydro hybrid generating facility could face curtailment during September to November.

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.

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[7] 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 Xe Kaman 1

PV system energy yields are estimated for Xe Kaman 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 10MW ground-mounted PV system is considered as the baseline case. For system of a larger installation capacity, multiple of the 10MWp 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 modeling. Central inverter design with 2500kWac Sungrow central inverters (SG2500HV) is used to reflect the design of the 40MW Sungrow floating PV project 300Wp 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 modeled 10MWac PV system (with installed DC capacity of about 12MWp) produces 18133 MWh/year, with a specific energy yield 1516 kWh/kWp/year and a Performance Ratio (PR) of 81.2%.

[7] 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 0-3. 10 MW ground mounted PV system.

Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray MWh	E_Grid MWh	PR
January	159.3	50.48	21.26	190.8	184.2	1918	1875	0.822
February	163.0	52.49	22.72	184.5	178.3	1835	1792	0.812
March	184.7	71.01	25.07	192.6	185.6	1896	1852	0.804
April	170.0	81.28	27.22	164.7	157.5	1618	1582	0.803
May	166.6	83.52	28.49	152.6	145.4	1501	1468	0.804
June	145.9	79.36	28.98	130.7	124.2	1287	1259	0.805
July	158.9	90.04	29.04	144.3	137.3	1426	1396	0.809
August	133.4	79.85	28.27	126.1	120.2	1247	1218	0.808
September	136.5	73.72	26.58	137.4	131.6	1366	1335	0.812
October	137.8	72.35	25.74	146.7	140.7	1460	1427	0.813
November	124.3	60.98	23.55	142.4	136.9	1433	1401	0.822
December	129.2	59.15	22.01	153.9	148.0	1564	1529	0.831
Year	1809.7	854.23	25.76	1866.7	1790.0	18549	18133	0.812

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

Baseline case – 10MW floating PV system

With roughly the same assumptions, a 10MW floating PV system is then modeled. The key difference here is however the modeling 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 11-4.

Table 0-4. Thermal loss factors used in the energy yield modeling for ground-mounted vs. floating PV systems.

	Uc (in W/m^2K)	Uv (in W/m^2K)
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 test bed in Singapore as well and plotted in Figure 11-10. As shown, the U-value can range from 20 to over 50 depending on the floating structure design.

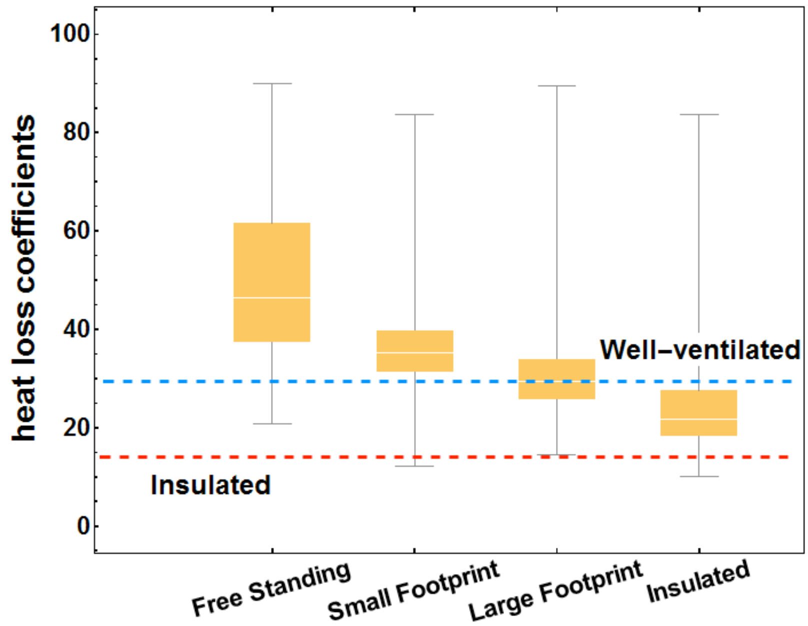


Figure 0-10. Extracted heat loss coefficients for different types of floating structures from the floating PV test bed in Singapore. Higher values correspond to better cooling. The floating structures are roughly categorized into a free standing type, and three close to water surface types, differentiated by the extent of water surface coverage beneath the modules (from small footprint to large footprint). "Insulated" refers to float structure that has a large water footprint identical to "large footprint", but with modules mounted in a compact, dual-pitch design. Also, indicated on the graph are U-values normally assumed for a well-ventilated and an insulated ground-based or rooftop systems in PV simulation.

Applying the U-values listed in Table 11-4, the simulated PV module temperature distribution can be observed and compared, as shown in Figure 11-11. It is clear that the floating PV module temperature is relatively lower. The modeled energy yield is thus higher.

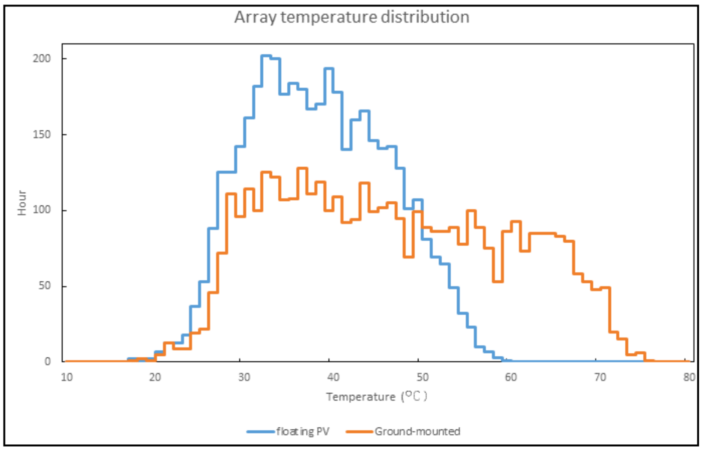


Figure 0-11. Simulated PV module temperature distribution, ground-mounted vs. floating PV.

Table 0-5. 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 11-5). As a result, keeping the same AC nominal power of 10MWac, the floating PV system uses fewer PV modules, i.e. 37,408 (floating) versus 39,872 (ground).

Table 0-6. 10MW PV floating system.

Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray MWh	E_Grid MWh	PR
January	159.3	50.48	21.26	190.8	184.2	1903	1860	0.869
February	163.0	52.49	22.72	184.5	178.3	1827	1784	0.861
March	184.7	71.01	25.07	192.6	185.6	1883	1839	0.851
April	170.0	81.28	27.22	164.7	157.5	1597	1561	0.845
May	166.6	83.52	28.49	152.6	145.4	1475	1443	0.843
June	145.9	79.36	28.98	130.7	124.2	1257	1229	0.838
July	158.9	90.04	29.04	144.3	137.3	1397	1367	0.844
August	133.4	79.85	28.27	126.1	120.2	1218	1191	0.841
September	136.5	73.72	26.58	137.4	131.6	1340	1310	0.849
October	137.8	72.35	25.74	146.7	140.7	1440	1407	0.855
November	124.3	60.98	23.55	142.4	136.9	1411	1379	0.863
December	129.2	59.15	22.01	153.9	148.0	1541	1506	0.872
Year	1809.7	854.23	25.76	1866.7	1790.0	18289	17877	0.853

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

The floating PV systems at Singapore's test bed demonstrates an initial PR of 83-91% (during Mar-Apr 2017). This outperforms a typical rooftop PV system in Singapore by about 5~15%.

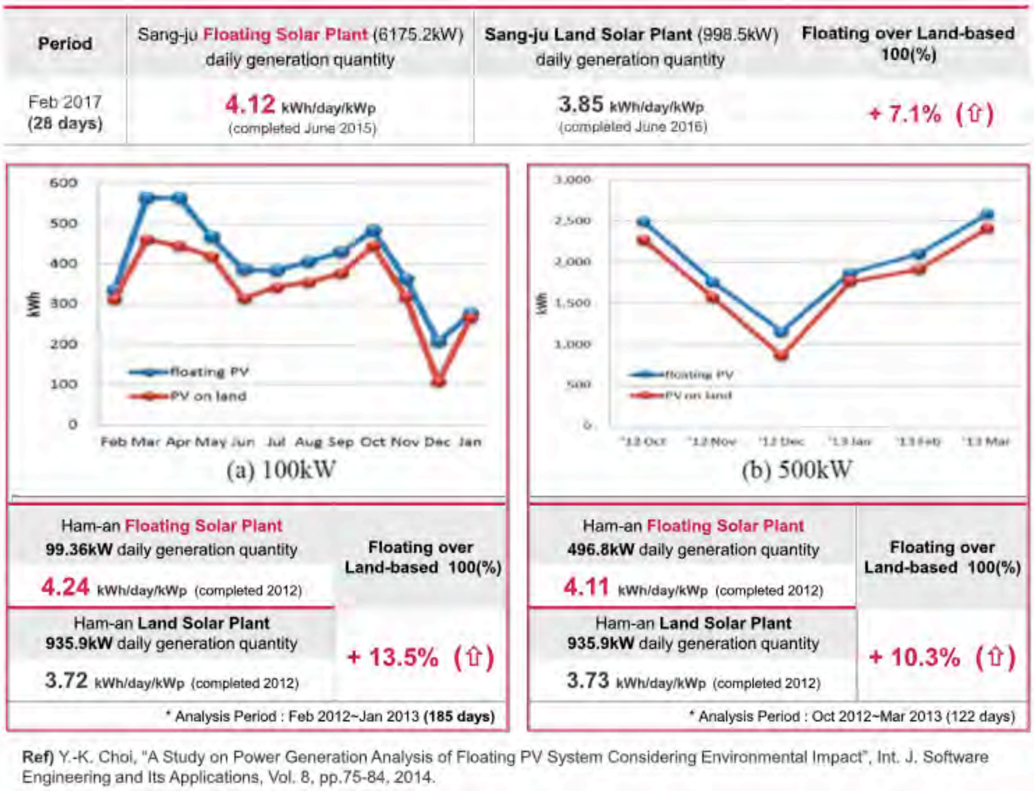


Figure 0-12. The relative performance gains of floating PV systems, as demonstrated by LG CNS in South Korea. (source: Intersolar Europe 2017/).

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 11-12). 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 0-13. 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 11-7 summarizes the comparison of the floating PV and ground-mounted systems.

Table 0-7. 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[8]	**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

Another observation on the monthly energy production shows again the impact of monsoon seasons in Laos. During the raining 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.

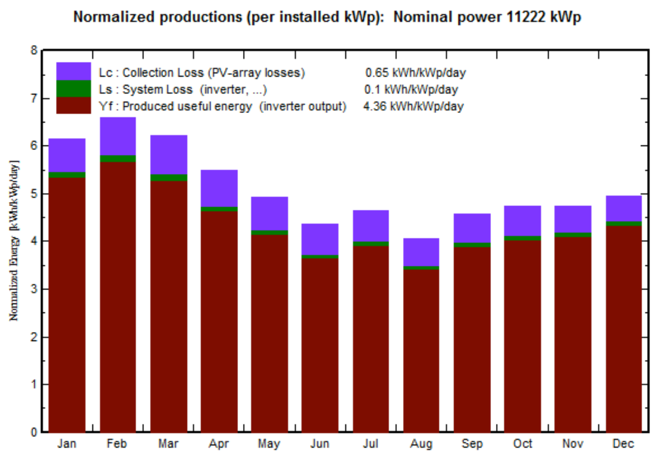


Figure 11-0-14. Normalized production per installed KWp, monthly average.

[8] For example, 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 11-15.

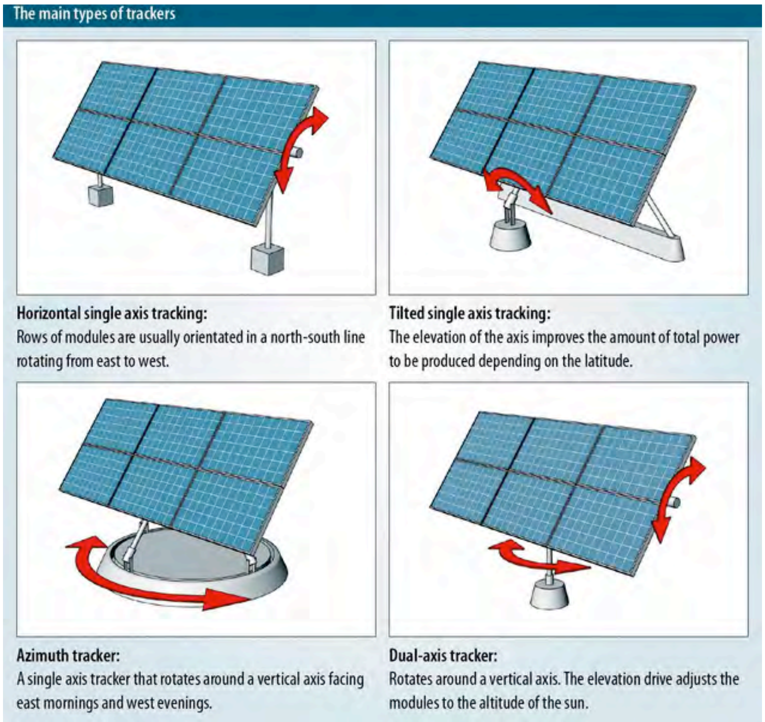


Figure 0-15. Main types of trackers for PV systems.

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.

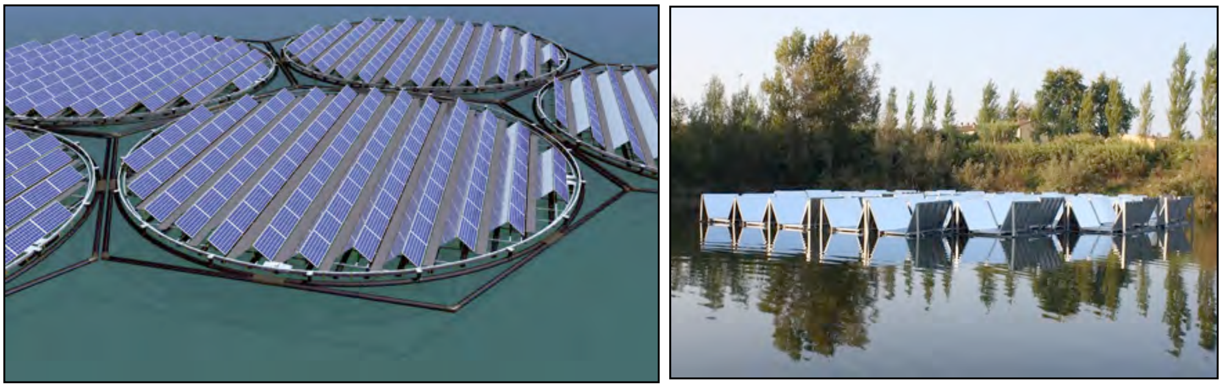


Figure 0-16. (Left) Floating Tracking Cooling Concentrator (FTCC) System concept. The tracking is realized as an azimuth tracker, i.e. rotates around a vertical axis. (Right) a FTCC pilot installation in an irrigation reservoir near Colignola, Pisa. Source: Tan, 2017.

Figure 0-17. Infratech wastewater facility, Jamestown, Australia, with azimuth tracking (1-axis, vertical).

Figure 0-18. 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 11-19 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.

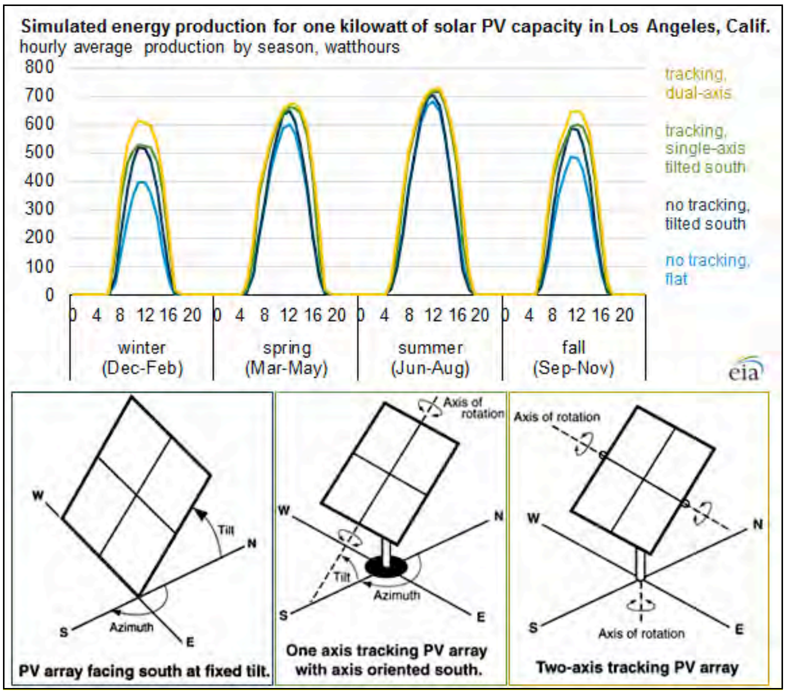


Figure 0-19. Simulated energy production.

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.

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 11-8 summarizes the energy yield calculations for the major design options.

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. As a result, the 6 PV system configurations analyzed boils down to 3 which worth further investigation, namely floating PV system with fixed tilt, ground-mounted system with fixed tilt and ground mounted system with 1-axis tracking.

Since the PV project is envisioned at a hydro power plant with large reservoir surface, the comparative advantages of a floating PV system are obvious. Qualitative comparisons between ground-mounted PV systems and floating PV systems were also summarized in Table 11-7 (above).

Table 0-8. Summary of energy yield prediction results for major design configurations.

	Ground-mounted PV			**Floating PV**		
	Fixed tilt	1-axis ** (tilted N-S)	2-axis	Fixed tilt	1-axis ** (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)	18,133	18,420	18,730	17,877	19,010	19,780
Specific Energy Yield (kWh/kWp/year)	1,516	1,868	1,900	1,593	1,929	2,007
Performance Ratio (%)	81.2	80.7	79.5	85.3	85.5	84.0

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.

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 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.

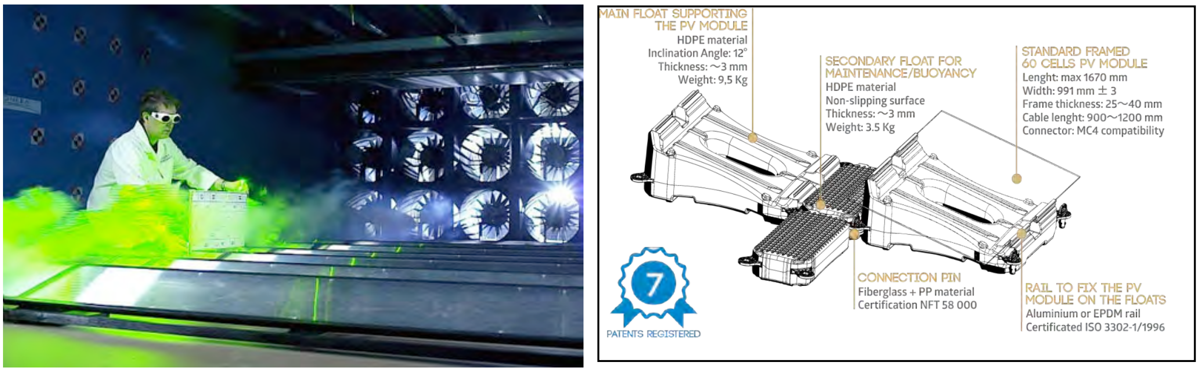


Figure 0-20. (Left) Laser tomoscopy in wind tunnel L2 (Lille) to test the wind resistance of solar panels intended to equip the first "industrial" floating photovoltaic power plant in the world, near Tokyo (Ciel et Terre Company). (Right) The design of Ciet et Terre (C&T) Hydrelio ®.

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

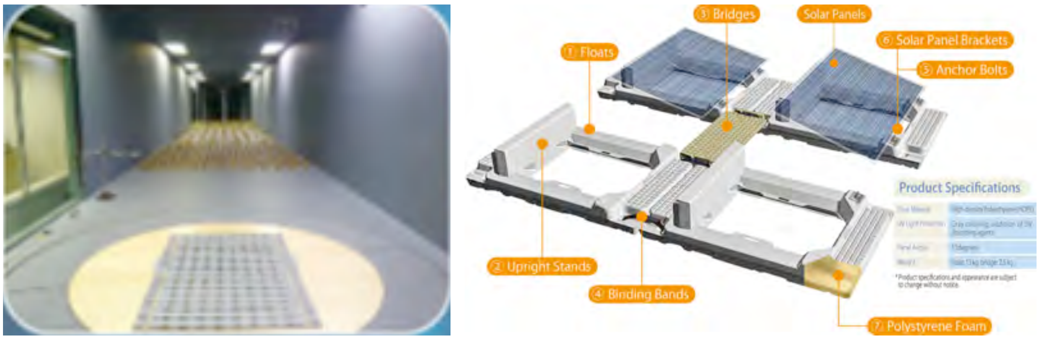


Figure 0-21. The floating platform design from Sumitomo (SMCC). The model has been tested in the Mitsui Sumitomo Construction Wind Tunnel Testing facility.

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.

Figure 0-22. The damaged floating PV system, with its west "rim" turned over by strong winds and high waves (source: Nikkei BP).

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.

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

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 11-23, which can be applied in low latitude tropical regions.

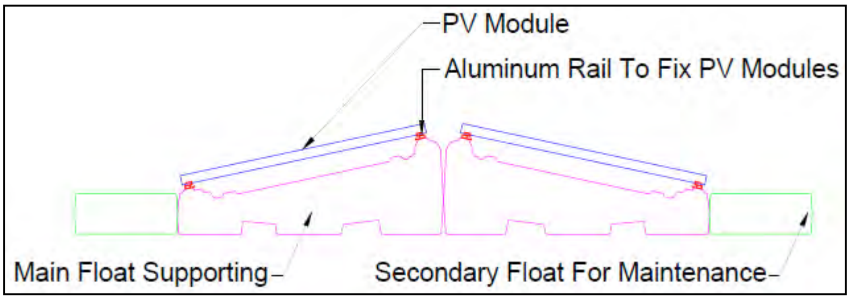


Figure 0-23. Dual-pitch configuration, as a solution to reduce wind load on floating PV modules / systems.

Ibiden Engineering has designed floating PV mounting system (Figure 11-24) 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 0-24. Ibiden's Floating Solar Mounting System.

Figure 11-25 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 Laos is reasonably well shielded behind Vietnam, where the wind speed will decrease rapidly once a storm reaches land. The roughness of the land terrain increases friction, but more critical, once over land, the system is cut off from its heat and moisture sources. Thus, Laos is not under the strong influence of tropical storms.

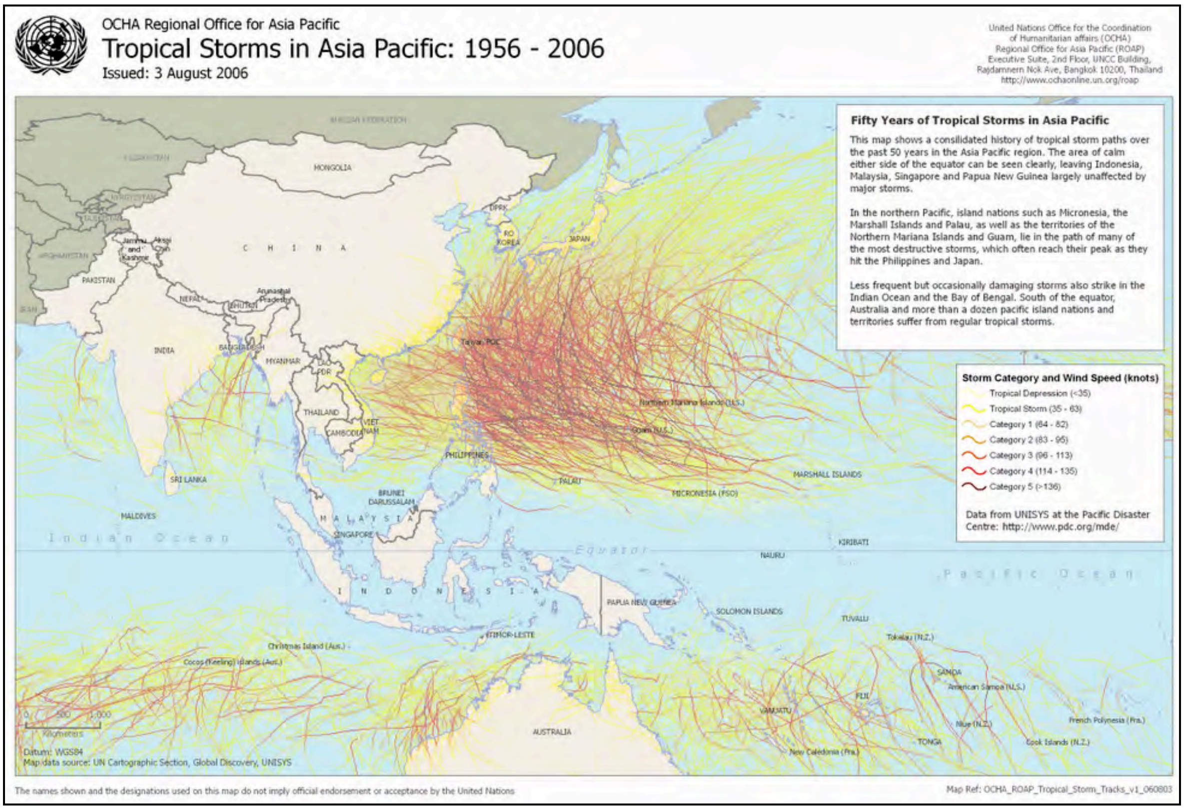


Figure 0-25. Historical records (paths and categories) of tropical storms in Asia Pacific over the past 50 years (1956-2006).

The historical wind speed data in Attapeu (Figure 11-26) also confirms that the highest wind speed is 28~38km/h (or 7.8~10.6m/s)[9]. 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.

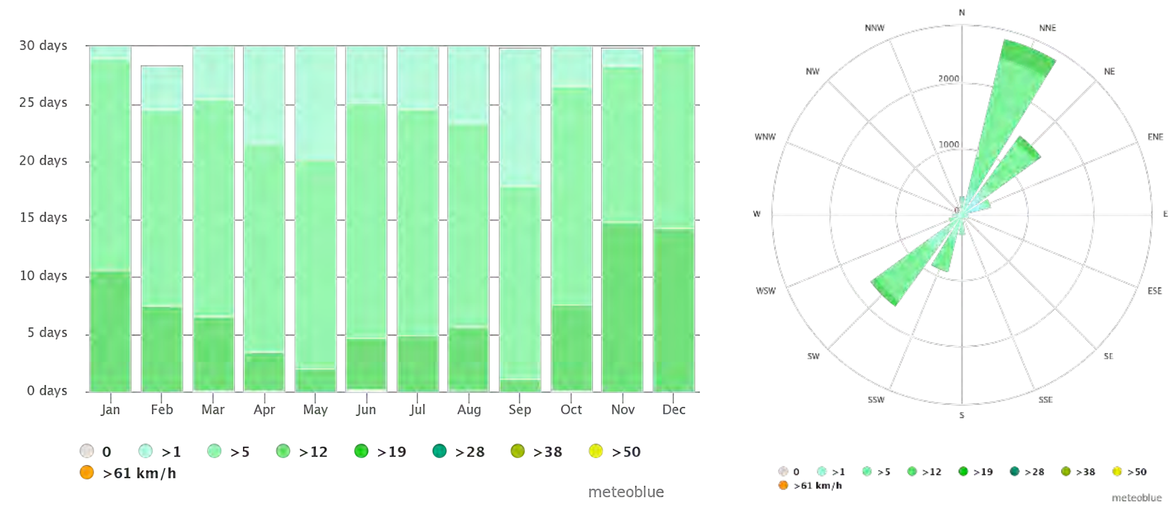


Figure 0-26. Wind Speed and Wind Rose diagrams for Attapeu (Source: meteoblue, 2017).

[9] Note that this wind speed data are typically measured at a height of 10 meters above the ground, and thus effective higher than the wind speed on ground.

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 11-27, 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.

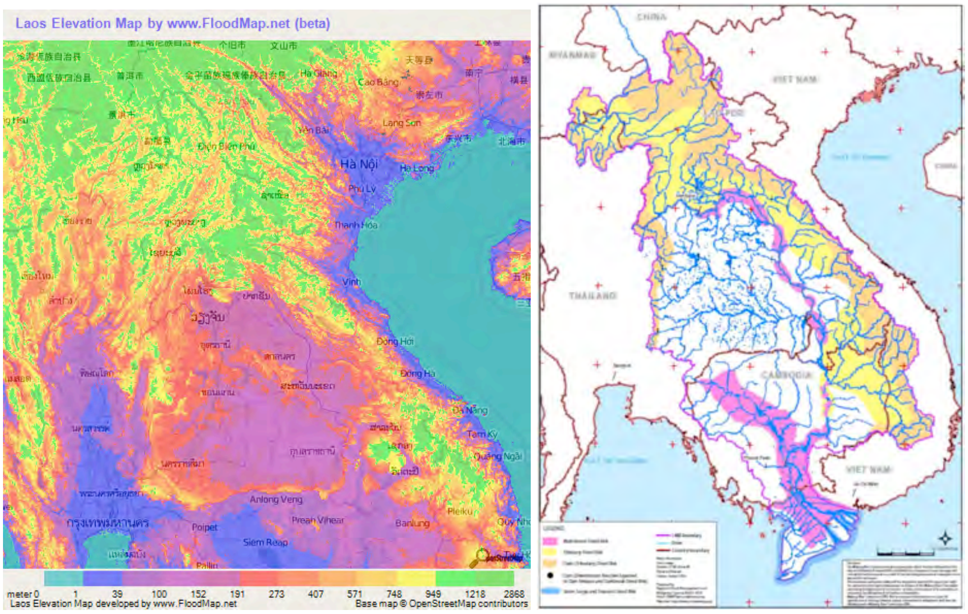


Figure 0-27. Laos's elevation map and the overview of Flood risk in Laos (Source: MRC,2010).

Text Box 0-1. 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 wind speeds, 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[10], 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.

[10] 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 0-28. Bird droppings situation as observed at the floating PV systems at Queen Elizabeth II reservoir.

Figure 0-29. Bird droppings situation as observed at the Singapore floating PV Test bed.

Potential solutions to the problem of bird droppings include, barriers, visual scare devices, ultrasonic repellers, recorded alarm calls, and laser devices.[11] 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 11-28), 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.

[11] 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 11-9 lists the largest floating solar PV projects worldwide.

Table 0-9. Largest floating solar PV plants worldwide (Dec 2017).

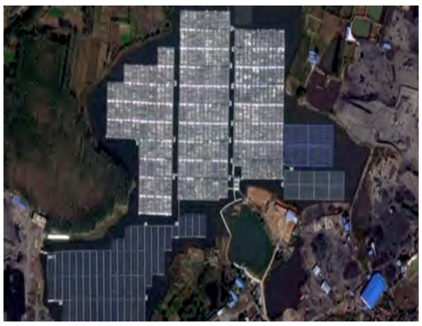
Rank	Size (kw)	Name of reservoir (lake) / Name of Plant	Country	City/Province	Operating from
1	**120,000**	Coal mining subsidence area, near Huainan [Top Runner Program]	China	Anhui Province	September, 2017
2	**60,000**	Coal mining subsidence area, near Huaibei [Top Runner Program]	China	Anhui Province	September, 2017
3	**50,000**	Coal mining subsidence area, near Huaibei [Top Runner Program]	China	Anhui Province	September, 2017
4	**50,000**	Coal mining subsidence area, near Suzhou [Top Runner Program]	China	Anhui Province	September, 2017
5	**40,000**	Coal mining subsidence area, near Huainan (Sungrow)	China	Anhui Province	May, 2017
6	**20,000**	Coal mining subsidence area, near Huainan (Xinyi Solar)	China	Anhui Province	April, 2016
7	**20,000**	Lake near Sanduzhen, Hang Zhou	China	Zhejiang Province	Aug, 2017
8	**8,500**	Wuhu, Sanshan	China	Anhui Province	July, 2015
9	**8,000**	Ling Xi Lake	China	Hebei Province	August, 2015
10	**7,500**	Kawashima Taiyou to shizen no megumi Solarpark	Japan	Saitama	October, 2015
11	**6,338**	Queen Elizabeth II reservoir	UK	London	March, 2016
12	**3,000**	Otae Province	South Korea	Sangju City Gyeongsang Bukdo	October, 2015
13	**3,000**	Jipyeong Province	South Korea	Sangju City Gyeongsang Bukdo	October, 2015
14	**2,991**	Godley Reservoir Floating Solar PV	UK	Godley	January, 2016
15	**2,449**	Tsuga Ike	Japan	Mie	August, 2016
16	**2,398**	Sohara Ike	Japan	Mie	March, 2016
17	**2,313**	Sakasama Ike	Japan	Hyogo	April, 2015
18	**2,000**	Reservoir in Kumagaya city	Japan	Saitama	December, 2014
19	**2,000**	Reservoir in Shiroishi-chou	Japan	Saga	Mar, 2015
20	**2,000**	Kinuura Lumberyard	Japan	Aichi	February, 2016
21	**2,000**	Yado Ooike (Sun Lakes Yado)	Japan	Hyogo	January, 2016

The list is partially from http://solarassetmanagement.asia/news/floating-plants-article

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 11-30 and Figure 11-31). 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 0-30. 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

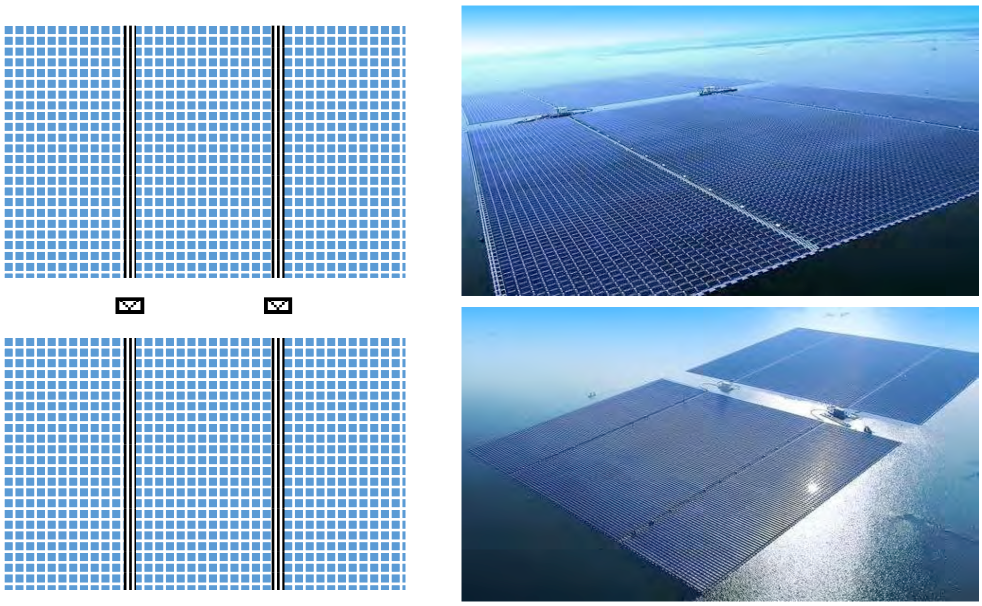


Figure 0-31. Basic building block of Sungrow floating PV arrays, with 2 units of 2.5MWac.

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 11-30 string inverters and AC combiner boxes can be placed on the floating platform (Figure 11-32), and then centrally stepped up and connected to the nearby substation.

Figure 0-32. 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 11-33). 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).[12]

Figure 0-33. 218 kWp C&T, at Alto Rabagão dam, Portugal. (Source: Moody's, 2017).

[12] 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 each new level of floating PV capacity at Xe Kaman#1 will need to take into consideration potential limitations in: (i) the capability of the Vietnam power system's (EVN) spinning reserve capacity to respond to the intermittency of PV power generation; and (ii) the evacuation capability of the 230kV grid transmission lines that tie the Xe Kaman#1 power station into the 500kV Pleiku substation (Figure 11-34) and via a new 230kV line to Xe Kaman#3 that connects to the 500kV Thanh My substation, both of which are about 190km away from Xe Kaman#1.

If significant increases in PV are planned to cover the existing Xe Kaman 1 reservoirs (e.g. 15% of its reservoir could generate 1200 MW of additional floating PV capacity) it will also be necessary to take into consideration the plans by EDL and EDC to interconnect their respective EHV systems.

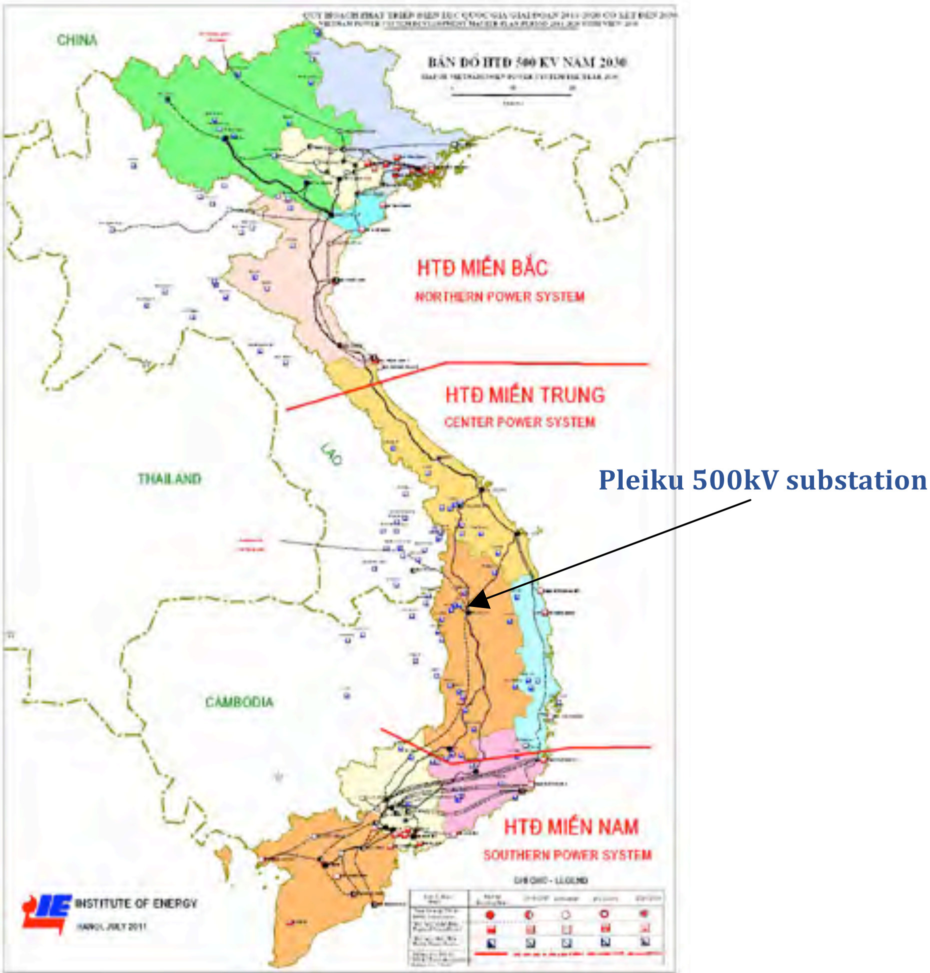


Figure 0-34. 500kV Transmission system in 2030. (Source: Institute of Energy: http://www.ievn.com.vn/tin-tuc/Approval-of-the-National-Power-Development-Plan-for-Period-2011-2020-with-Perspective-to-2030-1-838.aspx).

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 Xe Kaman#1 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.

In addition, this requires that there is sufficient space in the reservoir to store water rather than run water through turbines when PV production gradually increases in the morning hours, so that it can be released later in the day as the PV system productions decreases. This may be difficult to achieve, particularly during an abnormally wet season when the reservoir is in spill condition and turbines may be running 24 hours a day. Even in the dry season the hydro operator will wish to run turbines as at full a reservoir level as is possible (the higher the head, the greater the energy produced): however with the increasing availability and sophistication of weather forecasting and optimization software, this is not expected to be a major constraint.

Ability of the Xe Kaman 1 generators to operate in conjunction with floating PV installation

The hybridization of hydro and solar allows PVs to produce solar energy during the day while saving water for hydroelectricity to complete during intermittent times when the sun goes down. When water storage is possible, it also allows high-value hydropower to be produced at peak demand time. Another great advantage of hybrid operation is the benefit of using existing electrical infrastructure, including high voltage grid access and transformation devices. This drastically lowers the overall capex costs and makes projects happen quicker.

The purpose of PSSE load flow study described below aims to identify the potential power system related constraints of hybrid operation and evacuating the extra power from solar augmentation to the power grid for the planned initial increments of floating PV capacity. The associated constraints and issues explored in this report include the transmission line constraints; additional reactive compensation devices; and grid stability concerns.

Model setup

The double-circuit 230kV transmission line from Xe Kaman 1 to Pleiku 2 substation is currently the only power evacuation path for Xe Kaman 1 hydropower plant. The line has a designed capacity of 666 MW that will vary according to ambient conditions (Table 11-12). For example, on a hot sunny day with no wind, the circuit rating may be reduced to 500 MW and it will be important that both circuits are available to ensure that the line is not overloaded. As additional floating PV capacity is deployed at Xe Kaman 1, the transmission line could well exceed its n-1 rating capability and alternatively power evacuation plan should be identified.

Table 0-10. Transmission line ratings based on IEEE 738-2012[13].

		Dry Season				Wet Season			
Environmental Parameters		Still Day	Windy Day	Still evening	Windy evening	Still Day	Windy Day	Still evening	Windy evening
Ambient Temp	^0C	37	37	25	25	30	30	30	30
Conduct Temp	^0C	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 ἑ		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

Two simulation options have been explored in this report:

- Option 1: all the Xe Kaman#1 generation is evacuated through the existing transmission line from Xe Kaman#1 to Pleiku2.
- Option2: An additional interconnecting 230 kV line of about 70 km between Xe Kaman 1 to Xe Kaman 3 substation. Currently Xe Kaman#3 substation is connected to 500KV Thanh My substation in EVN grid. With the additional interconnections, power from Xe Kaman 1 can be exported to either Pleiku 2 or Thanh My substations. The additional line would be built within easy proximity to planned future hydro stations at Xe Kaman 2, 2A and 4.

In order to reveal the worst case condition for the transmission line loading, it was assumed that both the hydro generators and PV were generated at maximum levels.

Figure 11-35 shows the simulation model setup in PSS/E of Option 1. The Xe Kaman 1 and Xanxay power plants are on the left side of the model, which consists of (2*145 +2*16 MW) hydro power units and the floating PV farm. The power generated from Xe Kaman 1 is fed into Pleiku 2 through the 190 km 230 kV transmission lines. A constant load model is connected at Pleiku 2 substation to represent the system peak load. Pleiku 2 substation is modeled as an infinite bus with constant voltage. Reactive compensation devices may be needed at substations to maintain voltage stability.

The details of the model setup, along with the data assumptions provided by VLPJSC and used in this analysis can be found in Annex 11-2.

[13] 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.

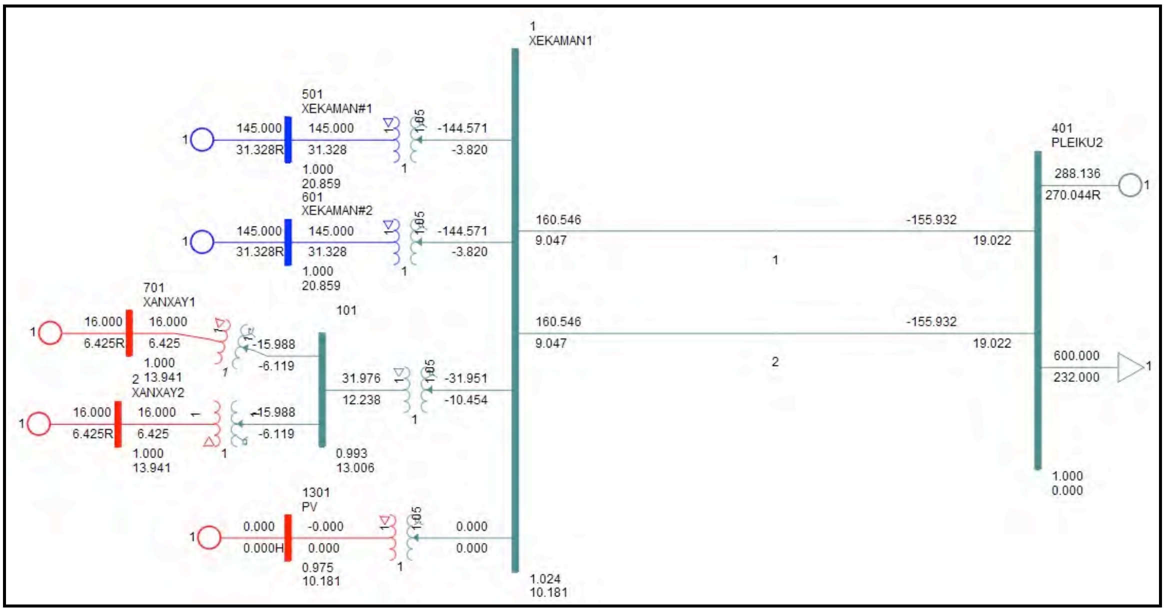


Figure 0-35. PSS/E simulation model setup for Option 1.

Table 0-11. Summary of load flow results for Option 1.

No.	Hydro output (MW)	PV output (MWp)	**X1-Pleiku2 Single circuit** loading (based on 666 MVA)	**X1-Pleiku2 circuit** loading (based on 800 MVA)	Reactive compensation
Case 1	322MW (145*2+16*2)	0	23.59%	19.48%	None
Case 2	322MW (145*2+16*2)	150	35.33%	29.48%	48 Mvar inside PV plant
Case 3	322MW (145*2+16*2)	400	54.95%	45.76%	190 Mvar inside PV plant
Case 4	322MW (145*2+16*2)	500	62.24%	51.83%	1. 280 Mvar inside PV plant 2. 150 Mvar at Xe Kaman#1 s/s

Option 2 represents a more comprehensive solution for solar power evacuation at Xe Kaman 1: interconnecting Xe Kaman 1 and Xe Kaman 3, as well as other existing and planned hydropower plants at Xe Kaman basin. Xe Kaman 3 power plant is located 70 km away from Xe Kaman 1 power plant. 90% of the energy output is exported to EVN grid via an 80 km 230 kV double-circuit transmission line from Xe Kaman 3 to the 500 kV Thanh My substation.

The simulation model of Option 2 is shown in Figure 11-36, for which the 230kV Xe Kaman 3 substation and 500 kV Thanh My substations are included. It is also assumed Thanh My and Pleiku 2 substations are connected through a 500 kV transmission line. All the existing and planned hydropower plants at Xe Kaman basin are included in the simulation. The simulation results are given in Table 11-11, and the associated load flow result figures are provided in Annex 11-2.

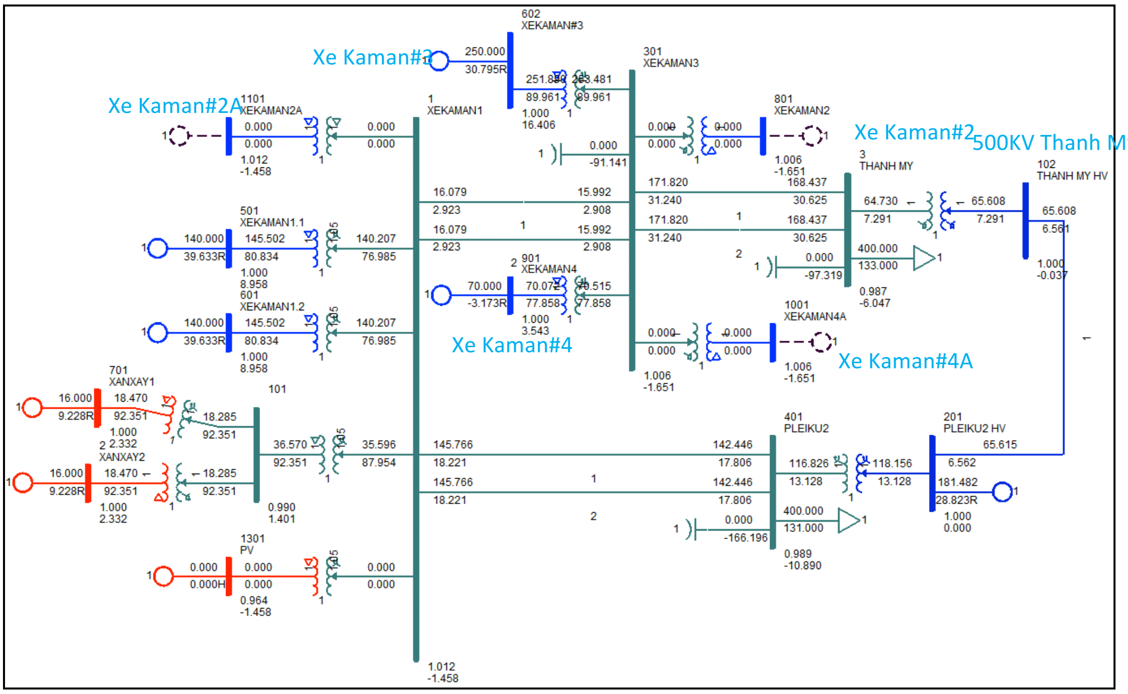


Figure 0-36. PSS/E simulation model setup for Option 2.

For case 1 and case 4, only the existing and hydropower projects under construction are considered in the simulation, namely Xe Kaman#1, Xanxay, Xe Kaman#3 and Xe Kaman#4. For case 5, all the planned hydropower plants are considered, which includes Xe Kaman#2, 2A and 4A.

Table 0-12. Summary of load flow results for Option 2.

No.	Xe Kaman#1 s/s Hydro output (MW)	Xe Kaman#3 s/s Hydro output	PV output (MWp)	X1-Pleiku2 single circuit loading (based on 666 MVA)	X3-Thanh My Single circuit loading (based on 550 MVA)	Reactive compensation
Case 1	322MW (X1+Xanxay)	320MW (X3+X4)	0	21.86%	31.20%	1.90 MVAr at Xe Kaman3 2. 100 Mvar at Thanh My 230kV 3. 170 MVAr at Pleiku2 230kV
Case 2	322MW (X1+Xanxay)	320MW (X3+X4)	150	27.39%	38.16%	1. 90 MVAr at Xe Kaman3 2. 100 Mvar at Thanh My 230kV 3. 170 MVAr at Pleiku2 230kV 4. 50 MVAr inside PV plant
Case 3	322MW (X1+Xanxay)	320MW (X3+X4)	400	36.47%	49.15%	1. 120 MVAr at Xe Kaman3 2. 180 Mvar at Thanh My 230kV 3. 250 MVAr at Pleiku2 230kV 4. 170 MVAr inside PV plant
Case 4	322MW (X1+Xanxay)	320MW (X3+X4)	500	40.02%	53.74%	1. 180 MVAr at Xe Kaman3 2. 250 Mvar at Thanh My 230kV 3. 300 MVAr at Pleiku2 230kV 4. 270 MVAr inside PV plant
Case 5*	386MW (X1+Xanxay+2A)	493MW (X3+X4+4A+2)	500	48.46%	65.18	1. 240 MVAr at Xe Kaman3 2. 300 Mvar at Thanh My 230kV 3. 380 MVAr at Pleiku2 230kV 4. 270 MVAr inside PV plant

** For case 1 and case 4, only the existing and under-construction hydropower are considered in the simulation, which are Xe Kaman#1, Xanxay, Xe Kaman#3 and Xe Kaman#4. For case 5, all the planned hydropower plants are considered, which includes Xe Kaman#2, 2A and 4A.*

Conclusions

Based on the evaluation of Option 1, we draw the following conclusions:

- Without solar augmentation the loading of the transmission line is 23.6%. After deploying 150 MW floating PV systems, the loading could reach 35.33%. Once the installed PV reaches 400 MW, the single circuit loading could reach 55% that would not fulfill the n-1 reliability criterion. Once the PV installation is 500 MW, n-1 criterion is no longer fulfilled even if the line capacity is upgraded to 800 MW. In that condition, a new power evacuation path must be provided otherwise power curtailment would be unavoidable.

- With the increasing power to be evacuated, reactive compensation devices must be provided to maintain voltage levels and thereby increase loading capacity. At the 230 kV bus connecting the floating PV-inverter plant. The preferred reactive compensation device would be STATCOM, which could dynamically maintain voltage stability according to the PV fluctuations. Additional compensation devices could be required at Xe Kaman#1 substation when the PV installation reaches 500 MW.

Based on the evaluation of Option 2 the following conclusions can be drawn:

- Once Xe Kaman 1 and Xe Kaman 3 are interconnected, the excess power from Xe Kaman 1 can be evacuated to EVN grid through the Thanh My substation and relief the loading pressure on the line to Pleiku 2. With 400 MWp solar PV, the loading levels on both transmission lines are below 50% and fulfill the n-1 operation criterion. However if the PV installation increases to 500 MWp, n-1 criterion will not be fulfilled on one of the lines.

- Additional reactive compensation devices will be required at various substations to maintain voltage stability, which may include the 230kV side of Thank My and Pleiku 2 substations, Xe Kaman 3 substation and the PV power plant itself.

Spinning reserve capability of Vietnam power system

A key concern of large scale grid-connected PV system is the short-term power fluctuations due to moving clouds, which may lead to large power ramp-rates and cause voltage and/or frequency fluctuations to the grid. For the Xe Kaman 1 solar augmentation project, PV fluctuations are not likely to be a major concern to the grid's stability performance. The reasons are las follows:

- The idea of hybrid operation of hydro and solar system is to minimize the PV fluctuation by regulating the hydropower, so that the total output power is smooth and predictable. From the grid point of view, the hybrid system is as dispatchable as conventional power plants. The experiences from Longyangxia project, which is the world largest hybrid hydro and solar system, show that the hybrid hydro and solar power plant is able to follow the grid dispatch curve within acceptable tolerance.

- EVN grid is a well-developed strong grid with interconnected transmission system. Currently the total generation capacity of EVN grid is around 42,300 MW, in which over 70% is hydroelectricity and coal. On the other hand, the penetration level of renewable energy such as wind and solar in EVN grid is very low. The grid should have abundant resilience to handle the PV fluctuations, especially since the proposed PV capacity is only around 1% of the total grid generation capacity.

- Due to the spatial smoothing of irradiance over large areas, the output fluctuation of a large scale solar PV power plant is significantly reduced. The solar ramp rate recorded from Longyangxia project (850 MW PV) during cloudy days is around 1pu/15mins

Conclusions

The load flow results show that the existing 230 kV line will experience constraints once the PV installation reaches 400 MWp. For a further PV capacity increase, it is recommended to upgrade the line capacity to 800 MWp. For any PV installation above 500 MWp, it is recommended to build new transmission lines for safe operation of the transmission lines.

The Economics of Floating Solar PV

Review of existing Floating Solar project cost information

In most press releases for new floating PV projects, the investment cost is typically not revealed. Selected news with some investment information are summarized in Figure 11-37, sorted by the month of commissioning. For the calculated system price per Watt-peak the exchange rates to the USD as of 17-Nov-2017 (from Bloomberg Markets) were applied. The following gives the list of systems analyzed:

1) 200 kW_p project in Berkshire, England, completed in 2014. This was the Britain's first floating PV system and the total investment was ~£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 mentioned to be ~700 million yen (Sourcing 71, 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, 2017a).

5) 2.4 MW_p project in Kagawa, Japan, completed in 2017. This project's name is the Noma Pond Solar Power Plant and is deployed, as the system number 4, under a FiT regime. The total project cost was mentioned to be USD $7 million (Renewables Now, 2017b).

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

7) 40 MW_p project in Anhui, China, was built on a former coal mine and completed in 2017. Total investment cost was around USD $ 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 (The Economic Times, 2017).

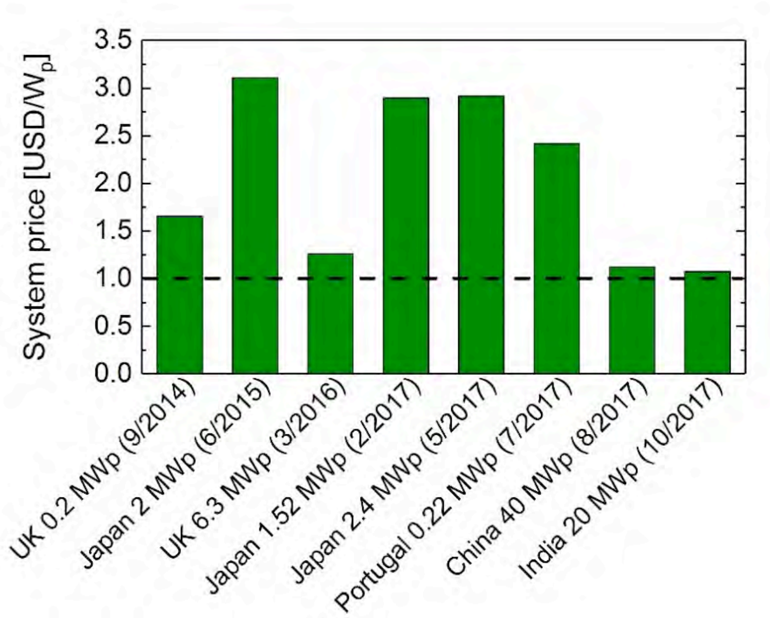


Figure 0-37. Selected news on Floating Solar projects where investment cost was revealed.

The system cost is highly location dependent, especially on the balance of system (BOS) cost (in which labor costs play an important role). In addition, larger systems benefit from economies of scale. Japan remains a region with relatively high system prices, which can be also observed for ground-mounted and rooftop solar systems when compared to the global average (GreenTech Media, 2017). The two most recent systems show that a system cost of ~USD 1.1/W_p appears achievable. More detailed information regarding break-down of the investment and operating and maintenance expectations could not be found. One recent report makes the statement that on a basis of "cost per watt" installed, floating should not deviate significantly from land-based photovoltaic (Hartzell, 2017).

Floating PV System Cost Analysis

The economic analysis follows the energy yield assessment which was performed comparing a 10 MW_p floating PV to a ground-mounted PV system, using a fixed-tilt design. The base case uses the assumption of an average annual irradiance assumption of ~1,867 kWh/m^2 and a performance ratio of 81.2% and 85.3% for the ground-mounted and the floating PV system, respectively.

Investment cost

A break-down of the current investment cost assumed for a 50 Wp installation for the two different system configurations is shown in Table 11-13 and the respective potential reductions over time in Table 11-14. Note that no land purchase cost, or rental for the water bodies, is taken into considerations. It is assumed that the major part of the system cost will be in USD. Despite the fact, that EPC companies might recruit locally, the EPC contract itself can still be done in USD. The detailed assumptions behind these figures are explained below.

Table 0-13. Assumed investment cost of a 50 MWp floating PV system (module prices as of 9-Nov-2017)

System cost break-down	Ground-mounted PV (USD) fixed tilt	Floating PV (USD) fixed tilt	Ground-mounted PV (USD/W_p) fixed tilt	Floating PV (USD/W_p) fixed tilt
Module	16,900,000	16,900,000	0.338	0.338
Inverter	3,250,000	3,250,000	0.065	0.065
Electrical work	10,500,000	10,500,000	0.210	0.210
Total PV equipment	30,650,000	30,650,000	0.613	0.613
Racking, civil work	9,250,000	-	0.185	-
Floating structure	-	11,000,000	-	0.220
Total structure equipment	39,900,000	41,650,000	0.798	0.833
Grid connection cost	1,500,000	1,500,000	0.030	0.030
Infrastructure	7,500,000	7,500,000	0.150	0.150
Total investment cost	48,900,000	50,650,000	0.978	1.013
Difference to ground-mounted fixed-tilt:		*4%*		*4%*

Table 0-14. 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%*

PV module prices

The significant reduction in global panel prices witnessed during 2016 (~38% from December 2015 to December 2016 levels) has decelerated during the first half 2017 and in some markets even reversed from its lowest level (see Figure11-38 for the historic learning curve and Figure 11-39 for the panel price development in 2017). The former decline was driven by overcapacity concerns, which have somewhat leveled off due to stronger than expected demand from China and as well the lingering import tariff trade dispute in the U.S. This has elevated panel prices in the U.S. by almost 45% (The Business Times, 2017). However, this “increase” should rather be short-lived, as continued cost cutting efforts by the manufacturing industry should “naturally” drive down prices albeit with a lower magnitude.

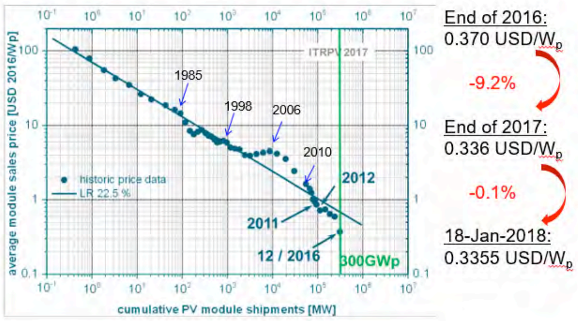


Figure 0-38. Learning rate curve for PV modules 22.5%, ITRPV 2017, pricing source: SSX (PVinsights, PV EnergyTrend).

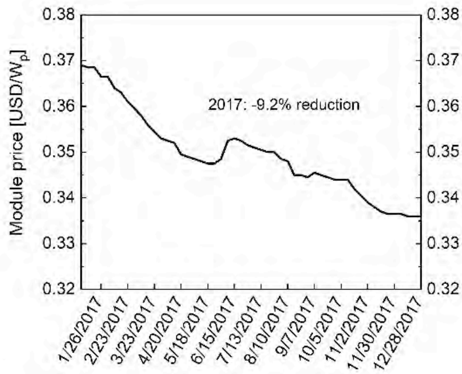


Figure 0-39. 2017 panel price development, data source: SSX (average from PVInsigts, PV EnergyTrend).

The International Technology Roadmap for Photovoltaic (ITRPV)(VDMA, 2017) foresees that module cost as a component within system cost overall will drop from a 53% share in 2017 to a 38% share in 2027. This would mean expected panel prices are ~25.2 USD/W_p in 2027, a 28% reduction compared to the year-to-date average of ~35.2 USD/W_p (until 9-Nov-2017). However the rate of reduction per annum is expected to decrease from ~8% in the first two years, to ~2% per annum thereafter (see Figure 11-40).

Until mid of 2017, total global installation forecast for the whole year averaged at the same level as was installed in 2016, ~75 GWp. Only recently several institutions increased expectations of installed basis quite significantly, i.e. EnergyTrend to 100.4 GW_p (PV Magazine, 2017a), IHS Markit to 90 GW_p (Solar Industry, 2017), PVTech expects annual shipping to exceed 90 GW_p (PVTech, 2017), SolarPower Europe to 100 GW_p (PV Magazine, 2017b), and IRENA expecting now 80-90 GWp to be installed by year end 2017 (Reuters, 2017). On average, including latest announcements made during 2H2017, the expected installed capacity estimation of these institutes for the entire year is ~90 GW_p, which reflects a 20% rise over last year (see Figure 11-40). The increasing competitiveness of PV globally should result in robust demand growth in the future. Manufacturing capacity is expected to grow as well with several top manufacturers either moving to higher-efficiency cell technologies (e.g. from the standard Al-BSF cell manufacturing process to mono-PERC and even adopting bifacial technologies) or deciding to expand with new manufacturing capacity. For example, the latest news of Tongwei to build two 10 GW_p cell manufacturing plants in China illustrates the optimism from some of the industry players (PV Magazine, 2017c), and it appears that under-capacity situations, as witnessed in the middle of the year, are rather short-lived phenomena.

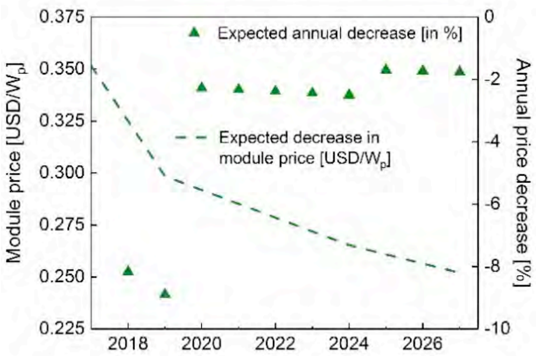


Figure 0-40. Expected future module price development according to ITRPV, using expected progression of cost elements of PV systems in Asia as a basis.

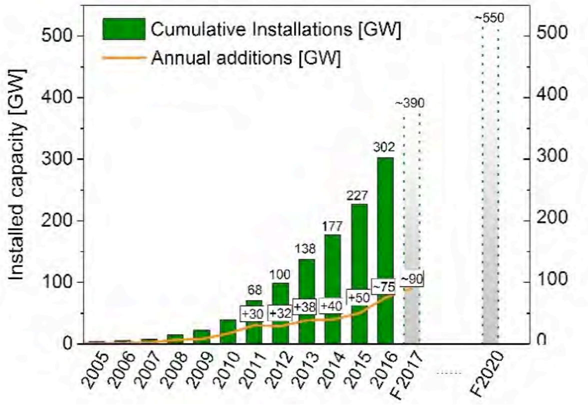


Figure 0-41. Global installed PV capacity and average forecast of different bodies including IHS, BNEF, Energy Trend, Solar Power Europe, GTM, IRENA F2020: SERIS market research.

The adoption of potential cost decreases for modules from the ITRPV proportional system cost assumption is shown in Figure 11-40. Those scenarios seem quite reasonable in terms of USD/W_p reductions especially with module manufacturing companies' continuing to focus on further reducing cost, e.g. Canadian Solar tries to undercut USD 0.30/W_p production cost by end of this year (PV Tech, 2017c).

PV 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, leveling 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 ~0.065 USD/W_p to ~0.050 USD/W_p over the next ten years.

Prices for floating structures, electrical works and others

The other cost component assumptions are based on SERIS' in-house 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).

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). Besides the supply-demand pattern, these are also influenced by international oil price progressions. Excluding this factor, some of the key player's target is to decrease the cost by ~0.01-0.02 USD/W_p annually. We assumed a reduction of 0.015 USD/W_p per annum, leveling off thereafter.

Levelised Cost of Electricity (LCOE) Calculation

LCOE methodology

The LCOE is calculated by dividing the entire lifecycle cost of the PV system by its cumulative solar electricity generation. It is presented in net present value (NPV) terms, with each year's cost discounted by the investor's hurdle rate. The underlying LCOE formula is shown in Equation 1:

$$LCOE = \frac{EPCI + IDC + \sum_{n=1}^{N} \frac{OM^{*} + IC^{*}}{(1+DR)^{n}} + \frac{IEI^{*}_{n=5,10,15,20}}{(1+DR)^{n=5,10,15,20}} + \sum_{n=1}^{N} \frac{TP + LP}{(1+DR)^{n}} + \frac{RV^{*}_{n=25}}{(1+DR)^{n=25}}}{\sum_{n=1}^{N} \frac{(IRD \times PR) \times (1-SDR)^{n}}{(1+DR)^{n}}} \quad (1)$$

*inflation-adjusted

The numerator sums up all the possible cost items over the system's entire lifetime. The investment cost comprises the equity project cost investment (EPCI) and the interest during construction (IDC). The annual operating cost is split in two parts, namely the operating and maintenance cost (OM) and the insurance cost (IC). The inverter warranty extension investment (IEI) represents the warranty extension cost for the systems' entire operating life. The year in which the warranty is extended varies with inverter suppliers. The model assumes a warranty extension at years 5, 10, 15 and 20. If a PV system is built on the premises of a taxable entity, tax payment (TP) should also be considered. This includes tax benefits incurring from higher depreciation and interest payment, and the indirect tax liabilities deriving from the reduced electricity cost. No tax implications have been taken into consideration for this work. In case a part of the upfront capital expenditure (CAPEX) was debt financed, the loan payments (LP) include annual interests and amortizations. At the end of the operational life, a residual value (RV) could be either subtracted or added, depending on the possible recycling value of the system and the system's removal cost. The denominator includes the system's lifetime electricity generation. The specific yield is the energy yield of the system in the 1st year, which is calculated by the product of the available irradiance (IRD) and the performance ratio (PR). After the first year, the generation output is annually adjusted according to the system degradation rate (SDR). Both values are discounted by the nominal discount rate (DR) for net present value calculations, which is based on the weighted average cost of capital (WACC) (see Equation 2):

$$WACC = (1-D) \times (RFR_{20} + b \times MRP) + D \times (RFR_{10} + DP)(1-TR) \quad (2)$$

Local risk free rates (RFRs) are based on respective government bond yield data, 10 years for the debt cost (RFR10), 20 years for the equity cost (RFR20), if available. Country-specific values can be used for the market risk premium (MRP), for the inflation rate (IF) and the tax rate (TR). OM, IC, IEI and RV are adjusted with inflation rates after the 1st year.

OPEX and other expense assumptions

Table 11-15 summarizes the annual operating expense assumptions. The operating and maintenance part assumes a ~40% premium for floating PV compared to ground-mounted 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 ~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 (Lazard, 2017).

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 floating PV systems, respectively.

Table 0-15. OPEX assumptions for a 50 MWp floating PV system.

Operating expense break-down*	Ground-mounted PV (USD) fixed tilt	Floating PV (USD) fixed tilt	Ground-mounted PV (USD/kWp) fixed tilt	Floating PV (USD/kWp) fixed tilt
Operating & maintenance	250,000	350,000	5.0	7.0
Insurance expense	155,000	215,000	3.1	4.3
Inverter warranty extension	236,000	236,000	4.7	4.7
Total	641,000	801,000	12.8	16.0
Difference to ground-mounted fixe-tilt		25%		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 (Flicker *et al*., 2012) inverter manufacturers give typically warranties over a 5-12 years' period. 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 life-time 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 5, 45% in year 10, and 60% in year 15. The values above in Table 11-15 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). Based on this methodology, the inverters are assumed to be replaced ~1.36 times in the 20-year period.

Financial assumptions

For this project, two discount rates have been used: (i) one with bank financing at commercial rates (see Table 11-16) and (ii) one including concessional bank financing (see Table 11-17).

For the first case, a 12-year bank loan has been assumed, with interest cost at a 5% premium over the current risk-free rates, funding 60% of the portfolio's CAPEX. In the second case, a 15-year concessional loan has been assumed, with a ~5% interest rate, funding 70% of the initial investment amount. Current yields of outstanding Vietnamese government bonds were used as an indication for the RFRs. The market risk premium is based on an investor survey (Fernandez, Ortiz and Acin, 2016) and the typical corporate tax rate has been assumed for Vietnam (Trading Economics, 2018).

No supportive tax depreciation schedule has been assumed. An inflation rate of 3.4% per annum has been used (2020 inflation assumption (Trading Economics, 2018b)). It is assumed that the construction period will last 12 months, which is relevant for the interest during construction (IDC) calculation which is added to the CAPEX assumption.

Table 0-16. Discount rate calculation based on "commercial" bank financing.

WACC (Weighted average cost of capital)			Comments
Risk-free rate	5.08%	a	Average yield of 15-year Vietnamese Government Securities (Jan-2018)
Market risk premium	9.90%	b	Market risk premium used in 71 countries in 2016, Pablo Fernandez
Current beta	1.0	c	Sensitivity of the investor's returns to market returns, > 1.0 more risky, < 1.0 less risky.
Cost of equity	**14.98%**	**d**	**= a + b x c**
Risk-free rate	4.77%	e	Average yield of 10-year Vietnamese Government Securities (Jan-2018)
Debt premium	5.00%	f	Likely additional credit spread investor pays over risk-free rate
Cost of debt	**9.77%**	**g**	**= e + f**
Equity ratio	40.00%	i	Equity portion for financing the PV installation
Debt ratio	60.00%	j	Debt portion for financing the PV installation
Corporate income tax rate	20.0%	TR	Corporate income tax rate of Vietnam
WACC	**10.68%**	**l**	**= d x i + g x j x (1 - TR)**
Risk Adjustment for Uncertainties	- %	h	Additional Uncertainty to WACC (country, environmental etc.) or adjustment to required hurdle rate
Discount rate (nominal)	**10.68%**	**DR**	**Taken as the discount rate, as inflation is as well taken into account on the cost side**
Inflation	3.40%	k	According to 2020 value from Trading Economics accessed 22-Jan-2018
Discount rate (real)	**7.3%**		
Debt Term (years)	12	**N**	Maturity for the portion of debt financing
Construction period (months)	**12**		In order to calculate the interest during construction (IDC)

Table 0-17. Discount rate calculation based on "concessional" bank financing.

WACC (Weighted average cost of capital)			Comments
Risk-free rate	5.08%	a	Average yield of 15-year Vietnamese Government Securities (Jan-2018)
Market risk premium	9.90%	b	Market risk premium used in 71 countries in 2016, Pablo Fernandez
Current beta	1.0	c	Sensitivity of the investor's returns to market returns, > 1.0 more risky, < 1.0 less risky.
Cost of equity	**14.98%**	**d**	**= a + b x c**
Risk-free rate	4.77%	e	Average yield of 10-year Vietnamese Government Securities (Jan-2018)
Debt premium	- %	f	Likely additional credit spread investor pays over risk-free rate
Cost of debt	**4.77%**	**g**	**= e + f**
Equity ratio	30.00%	i	Equity portion for financing the PV installation
Debt ratio	70.00%	j	Debt portion for financing the PV installation
Corporate income tax rate	20.0%	TR	Corporate income tax rate of Vietnam
WACC	**7.17%**	**I**	**= d x i + g x j x (1 - TR)**
Risk Adjustment for Uncertainties	- %	h	Additional Uncertainty to WACC (country, environmental etc.) or adjustment to required hurdle rate
Discount rate (nominal)	**7.17%**	**DR**	**Taken as the discount rate, as inflation is as well taken into account on the cost side**
Inflation	3.40%	k	According to 2020 value from Trading Economics accessed 22-Jan-2018
Discount rate (real)	**3.8%**		
Debt Term (years)	15	**N**	Maturity for the portion of debt financing
Construction period (months)	**12**		In order to calculate the interest during construction (IDC)

Other assumptions and LCOE results

The annual degradation rate has been assumed to be 1% per annum for each of the system configurations. The LCOE is calculated on a pre-tax basis (see Table 11-18). It can be observed that the LCOE of the different system configurations do not differ significantly and that the higher initial capex for the floating system can be balanced out with the ~5% higher expected output.

Table 0-18. LCOE calculation for a 50 MWp floating PV system.

Energy output (GWh), LCOE (USD cents/kWh)	Ground-mounted PV fixed tilt	Floating PV fixed tilt
Produced electricity (1st year), GWh	*75.8*	*79.6*
Difference to ground-mounted fixed-tilt:		*5%*
LCOE at discount rate 7.2%	7.2	7.3
LCOE at discount rate 10.7%	9.7	9.8

Sensitivity analysis

The LCOE of 7.3 USD cents/kWh of the floating PV fixed tilt has been used as a base-case, using the discount rate of 7.2%. Figure 11-42 illustrates how the LCOE differs based on potential changes in underlying parameters. It can be observed that access to debt financing, the initial capital cost and quality aspects of the system (i.e. operational years, performance ratio) are key factors influencing the LCOE.

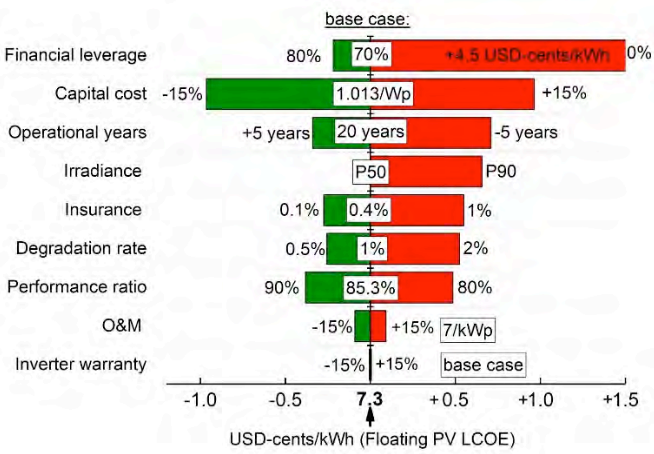


Figure 0-42. Sensitivity analysis of the defined base-case of a floating PV system at 7.4% discount rate.

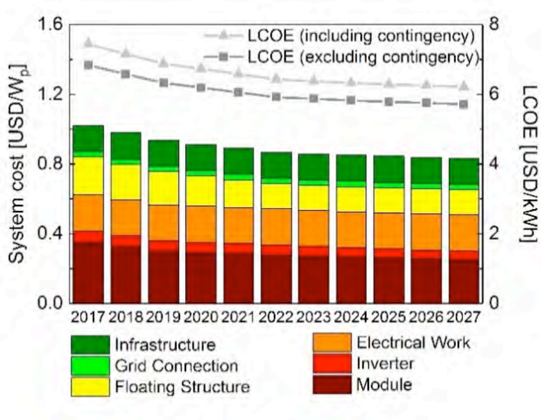


Figure 0-43. LCOE progression over time taking into account declining system cost assumptions.

The LCOE is expected to further decline with the projected downward trend of specific system price components, following the assumptions and results in Table 11-14 (see Figure 11-43). A 10% cost contingency has been added to include a more conservative value.

Residual Value of PV Assets

For the "base-case", a 20-year operational life-time has been assumed, which is a rather conservative approach, given the 25-year power output warranty provided by PV module manufacturers. It is therefore noteworthy that most probable the system can last much longer, knowing that first panel manufacturers now even give warranties up to 30 years.

Nevertheless, the following provides an estimation of the residual value in year 20, based on a set of relevant questions, such as:

- Re-selling value of module, transformers, inverters, floating structure in year 20?
- Scrap value of recyclable material (aluminum, silver, copper, glass?)
- Removal cost (if installation companies could re-use it, someone might remove it free-of-charge)
- Cost for reinstatement of site to original conditions? (removal of anchoring and piles, demolition of potential inverter room if there was a need for it, site clearing and patching etc.)

The components of current CAPEX estimation (see Figure 11-44) shows that the PV modules' contribution is still the highest followed by the floating structure and electrical components. The question remains, whether there is still a value left after operating for 20-years for the inverters, transformers and floating structures.

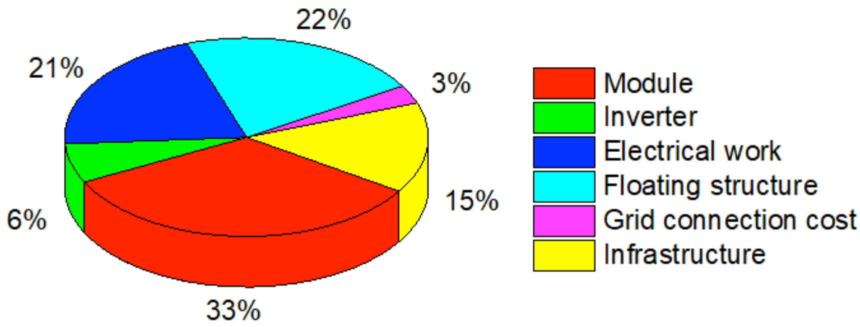


Figure 0-44. Break-down of CAPEX estimation for 50 MWp floating system of ~50.65 USD million (~1,013 USD/Wp).

As outlined in Figure 11-40, panel prices are expected to decline ~28% over the next 10 years. In addition, it is assumed that cell efficiency and therefore the area factor (panel output) will improve to ~25% and ~410 W_p, respectively, by ~2040 based on investigations carried out by SERIS for the Solar PV Roadmap, Singapore (SERIS, 2014). It is therefore expected that 20-year old panels and other components have no re-selling value anymore. Proper recycling of PV modules is paramount to ensure the solar technology remains sustainable. Various recycling techniques are researched and studied and in some countries already applied. For example, recovery rates of ~65-70% by mass appear already achievable today which are in line with the only existing regulation for PV panel recycling to date, the EU WEEE Directive (IRENA, 2016). Figure 11-45 and Figure 11-46 visualize the material used in typical crystalline PV panels.

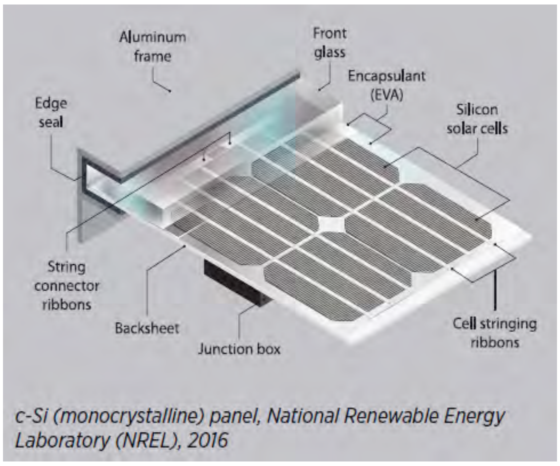


Figure 0-45.: Composition of a typical monocrystalline panel (IRENA).

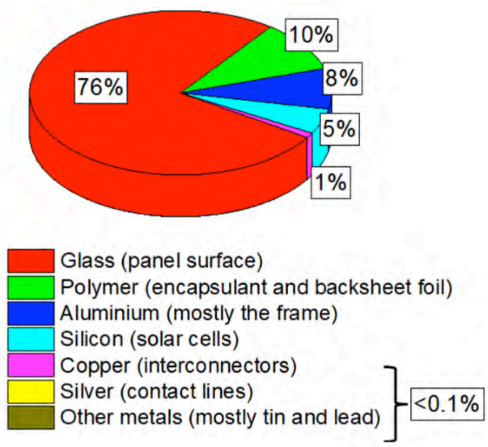


Figure 0-46. Materials used for typical crystalline silicon PV panels (by weight, figures used from IRENA).

Based on this information, a "high-level" estimate has been performed to investigate in recycling values of PV module components (see Table 11-19). The total weight is based on the assumption that 310 W_p modules were used at ~18 kg. The different price estimates are based on current price sources (for glass (IRENA, 2016), for aluminum and copper (InvestmentMine), for silicon assuming a 70% recovery rate[14] and for silver[15]). They could be highly difference in

[14] PVinsights. Available: http://pvinsights.com/, accessed 28.1.2018.
[15] Silverprice. Available: https://silverprice.org/, accessed 29.1.2018.

the future. In addition, the availability of recycling programs will vary from country to country. It can be seen that while glass is the biggest component in terms of weight, it is the lowest in terms of recycling value. Sealants and polymers are still hard to recover today, new processes are required to extract these materials in the future.

Table 0-19. Estimation of PV module recycling in year 20 for a 50 MWp floating system.

Material	In%	Total kg	US$/kg	Value $US	In %
Glass	76	2,206,452	0.03	66,194	2
Polymer	10	290,323	0	0	0
Aluminum	8	232,258	2.2	513,987	15
Silicon	5	145,161	11.0	1,117,742	32
Copper	1	29,032	6.9	200,468	6
Silver	0.1	2903	563	1634,516	46
Total				3,532,906	

For the entire system, a high-level estimate of the remaining potential value in year 20 is provided in Table 11-20. Uncertainties do exist in the removal cost of the different parts and also to what extent re-instatement work is required. For this work is it assumed that recycling value will be more or less offset by removal and re-instatement cost. Hence no residual cost nor residual value has been taken into account for this financial assessment.

Table 0-20. High-level estimate of the residual value of a 50 MWp floating PV system.

	Note	CAPEX assumption	Residual value estimate in 20 years
Module		16,900.00	
Removal cost	(1)		-2,900,000
Potential recycle cost			3,500,000
Net value			600,000
Inverter	(2)	3,250,000	-490,000
Electrical work		10,500,000-	
Copper in cables	(3)		1,100,000
Removal cost	(4)	1,100,00	-800,000
Net value		-800,000	300,000
Floating structure	(5)	11,000,000	
Grid connection	(6)	1,500,000	-75,000
Infrastructure	(7)	7,500,000	-375,000
Total investment cost		50,650,000	-40,000

Notes

(1)Removal cost $1/kg

(2)15% of initial cost assumed as removal cost

(3)250 m DC cabling, ~8000 strings,~80kg/km

(4)15% of half of initial CAPEX, other half expected to be manpower

(5)Assuming that potential re-use value offset by removal cost

(6), (7) 5% of initial CAPEX for removal/reinstatement works

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.[16]

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 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 11-47 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 (unsmoothed) output ramp rates of the PV project (the red line in Figure 11-47) 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 11-47, 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).

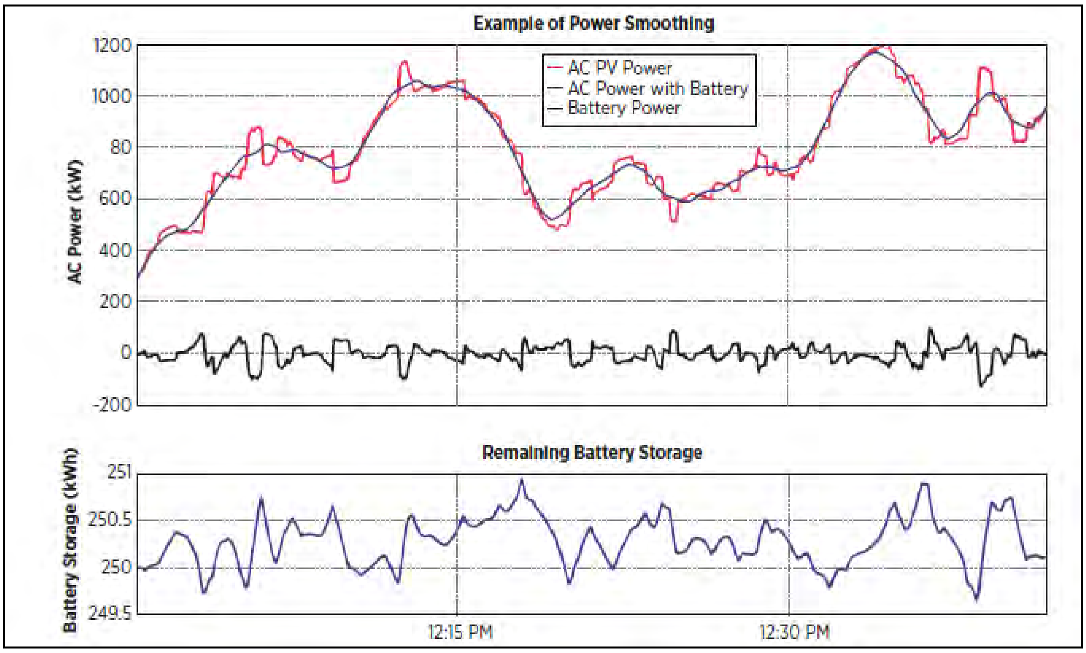


Figure 0-47. Battery for power smoothing. (Source: Johnson *et al.*, 2011).

[16] In the jargon of storage battery economics, this is described as "arbitrage".

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).[17]

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)
- 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.[18] 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.[19]

Cost of battery storage

The most common measurement of utility scale battery storage systems as USD/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 USD/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 540 MW in 2014 to 21,000 MW by 2024, with a learning curve comparable to that experienced for PV.[20] 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 $900/kWh. Tesla automobile's claims that it

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

[18] 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.

[19] http://www.energystoragenetworks.com/might-flywheels-impact-transmission-grid-renewables/

[20] *Energy Storage Market Outlook 2015*, Renewable Energy World, February 11, 2015.

will achieve $250/kWh may take some time, but clearly automobile use will be the main driver for technology innovation in batteries. Figure 11-47 below shows recent trends and forecasts.

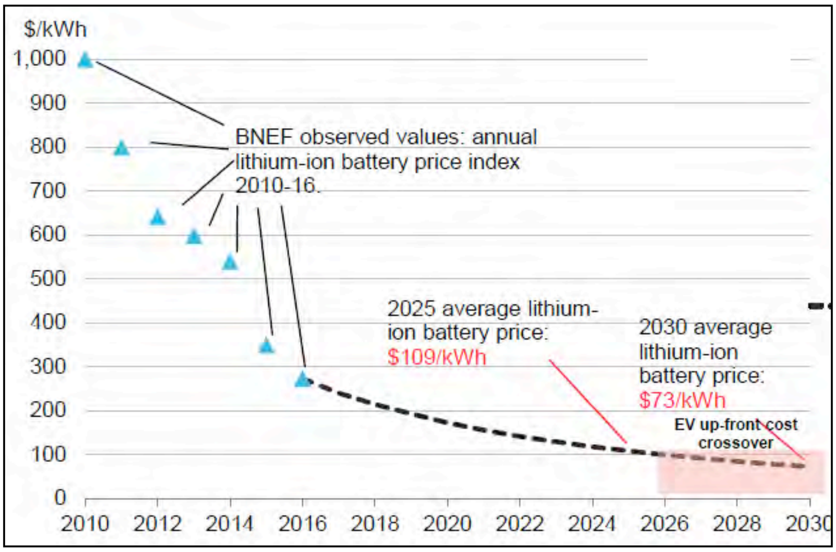


Figure 0-48. Expected Battery storage costs. *Source*: Bloomberg New Energy Finance. *Note*: Historical prices are nominal; future prices are at constant 2016 US$.

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 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%.

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. These problems are avoided by flywheels, whose life is not affected by charge/discharge cycles. The prospects for further 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 XK1

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 EVN grid. 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 XK1, 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 principals involved.

First, note Figure 11-49 shows the same profile as shown in Figure 11-46, 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 11-47. 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 since the ramp rate is 150MW/minute.

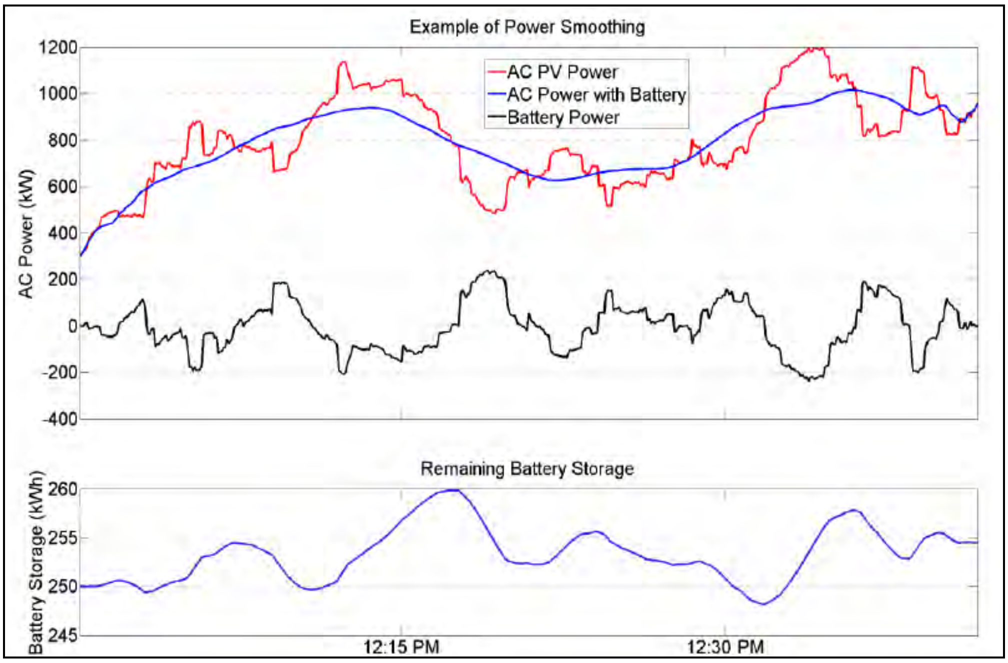


Figure 0-49. Power smoothing for longer time scale smoothing.

Table 11-21 presents an 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.

This of course says little about the potential impact of large PV at XK1. However, it does suggest that frequency and voltage issues from solar PV variability may not be a great as is sometime suggested.

Table 0-21. 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%

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 USD1,200/kWh. With 500kWh of storage, this results in a cost of USD600,000, about 25% of the likely capital cost of the PV plant itself.

In Column [3] we scale this to 100 MW at XK1, using the same costs as for La Ola. Note that its output represents only 4% of the 2020 peak load in the Vietnam grid. However, 2009-2011 costs will have decreased dramatically by 2020: in Column 4 we assume that battery costs would have declined to USD500/kWh and PV costs to USD950/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 11-44, the range of remaining battery storage varies only by some 15 kWh. This over-sizing 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 0-2. 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 11-19.

			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 XK1 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 and control intervals of the XK1 turbine-generators are known in detail, and detailed PSS/E model simulations can be carried out. 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 XK1 given their state of general commercial availability.

Financial Assessment

This preliminary assessment of the impact of financing options on the financial cost of solar PV power to EVN is based on the alternative financing packages shown in Table 11-22 – 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 0-22. 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. [21]

Other assumptions in the financial analysis are as follows:

- The calculations are in nominal US$,
- The PPA is assumed to have a constant value denominated in US$ (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.

[21] The calculation of equity returns based on the so-called "Capital Asset Pricing Mode." requires, among many other assumptions, a value of "beta", the sensitivity of investors returns to market returns, and "risk-free rates" . This is plausible for the USA or countries with established capital markets, but which would require quite arbitrary assumptions for a country like Laos.

The results of this simulation are shown in Table 11-23. 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 0-23. 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 11-24 by about 0.9 USc/kWh for commercial finance.

Table 0-24. 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 11-50 shows the results of a full sensitivity analysis for most of the uncertainties in such calculation. This shows a typical range of uncertainty of ±0.5 USc/kWh.

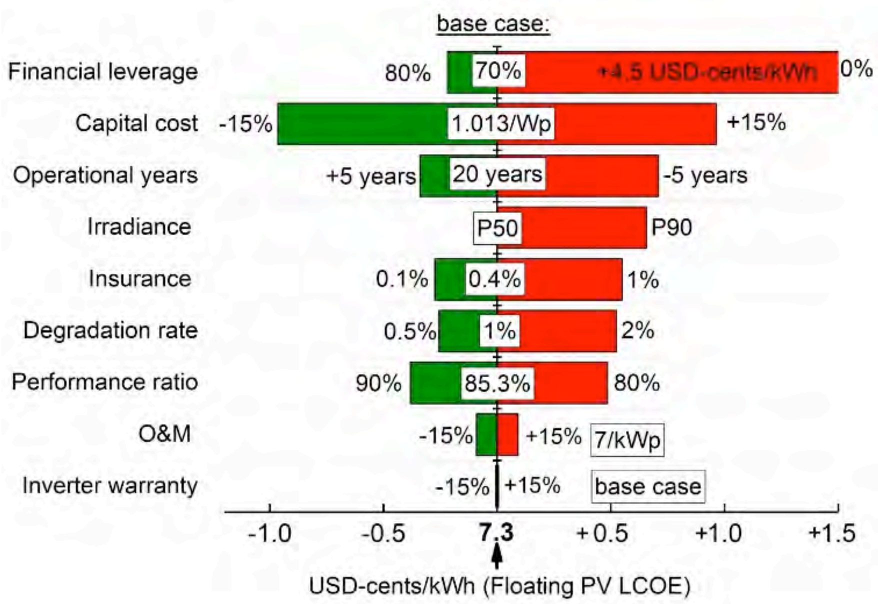


Figure 0-50. Sensitivity analysis of the defined base-case of a floating PV system at 7.4% discount rate. Source: SERIS Financial model.

Note that these results are for a first tranche of 50 MW 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 11-25.

Table 0-25. 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 11-26.

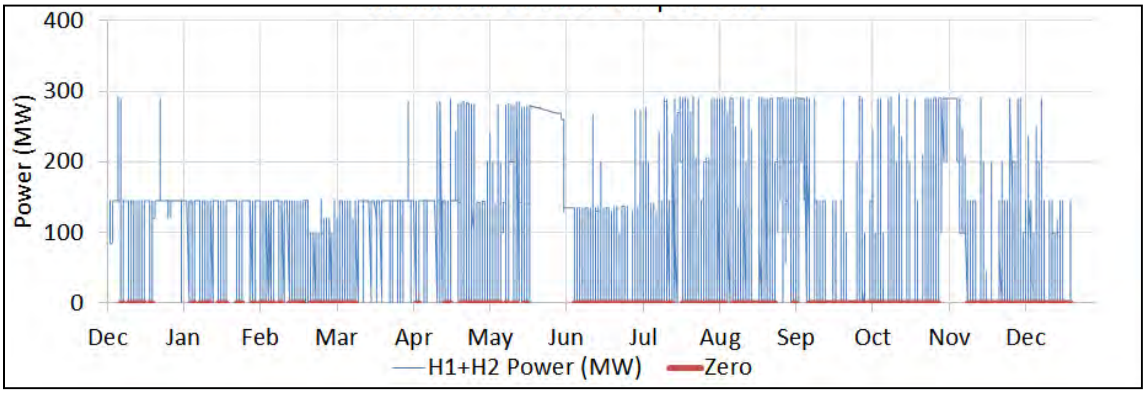
Table 0-26. Equity return at given tariffs (excluding integration costs, 10% reduction in CAPEX).

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%

Integrated operation of PV and Hydro

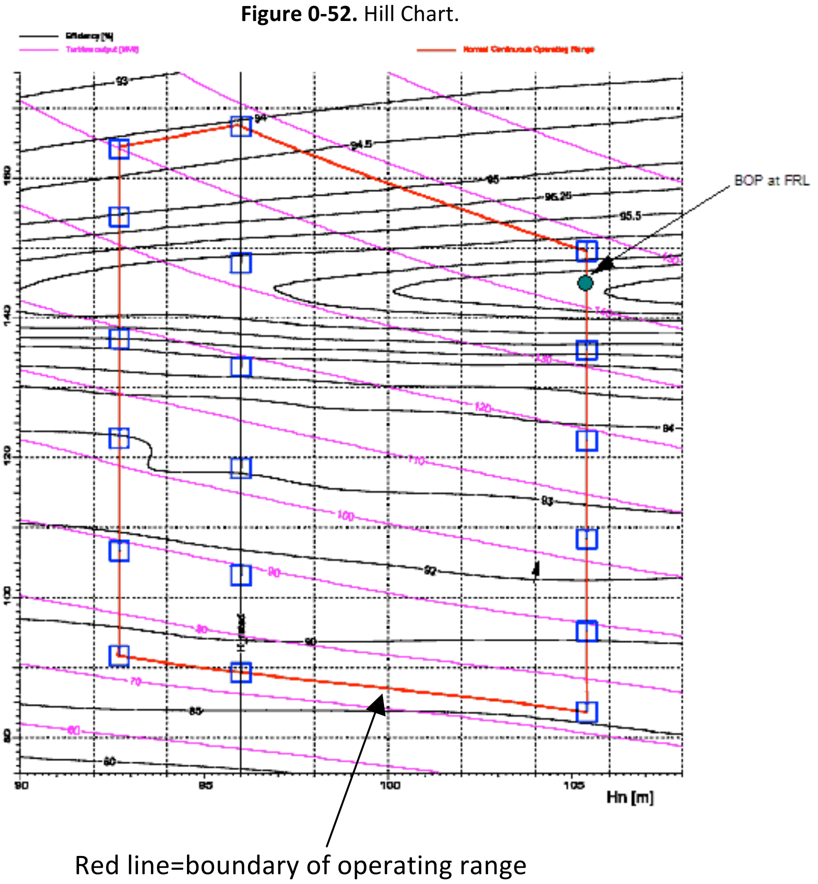
Figure 11-51 shows daily power generation at Xe Kaman 1 in 2017. The seemingly binary operation of the project (either one or both units at full discharge, or no generation at all) is a simple consequence of a maximization of total annual energy production.

Figure11- 0-51. Xe Kaman 1 power generation 2017.



The explanation lies in the performance characteristics of hydro turbines, in which efficiency is a function of the head and discharge, represented in the so-called Hill Chart (Figure 11-52), in which the contour lines represent the efficiency. For any given reservoir level, one selects the discharge that results in greatest efficiency (the so-called best operating point).

Figure 0-52. Hill Chart.



In Figure 11-51 we observe many days in which there is no generation, and in some case, even two-day periods without generation (for example 2nd and 3rd September). This happens when the actual reservoir level is above the rule curve (i.e. the target level of the reservoir), so one lets the reservoir fill rather than discharging (and generating power). Figure 11-53 shows the reservoir level since the start of operations in 2016.

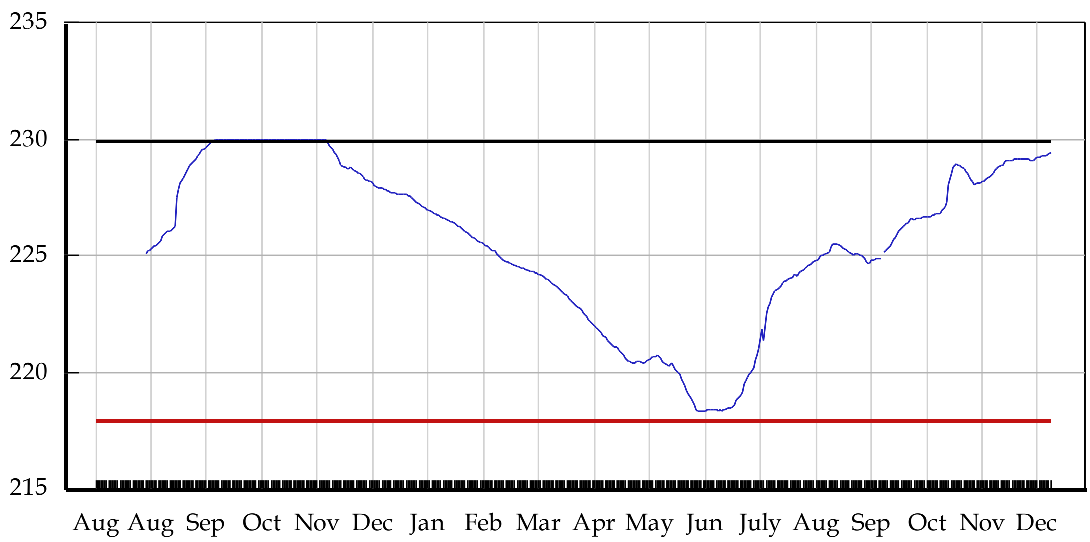


Figure 0-53. Reservoir levels.

The general operational policy is to run the project in such a way as to the extent possible, avoid spill – which represents lost revenue to VLPJSC. As shown in Figure 11-54, this was achieved in 2017. But if there are late storms (as evidently occurred in 2016), spill may be unavoidable.

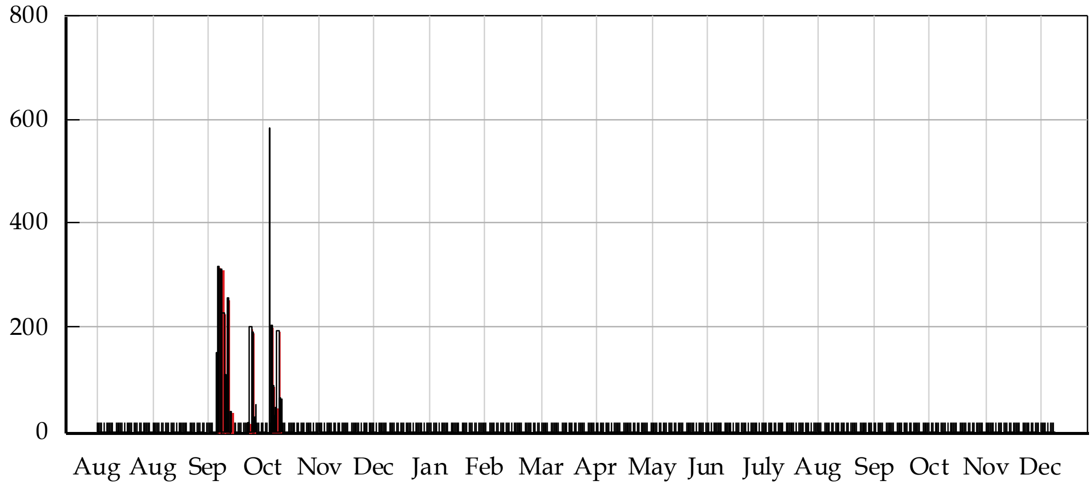
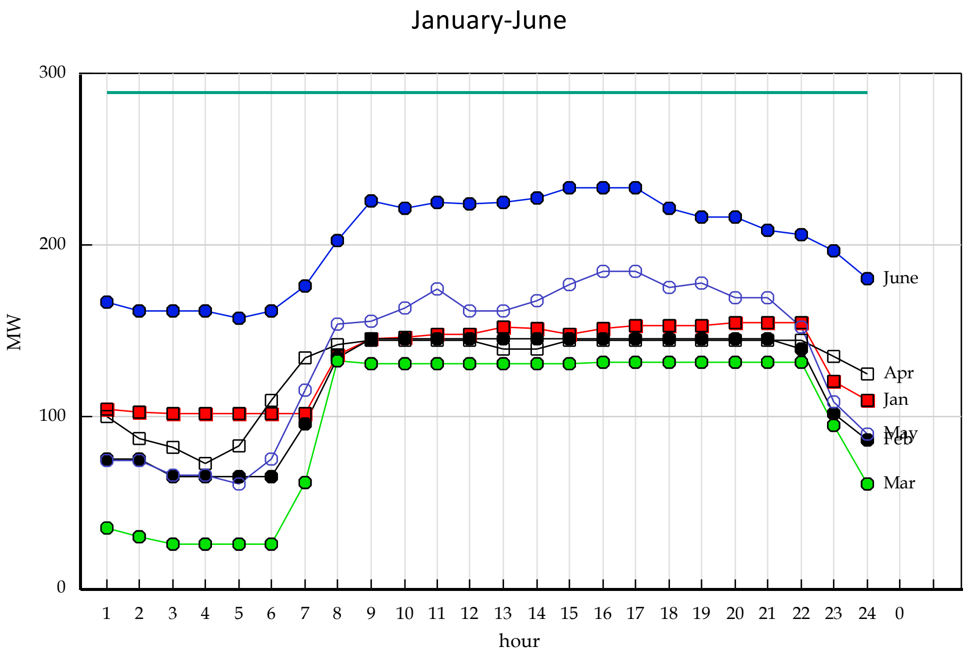


Figure 0-54. Spill at Xe Kaman 1.

According to information received from VLPJSC, the annual production plan is agreed for each year, then modified on a weekly basis according to hydrological conditions. But within that plan, how the project is operated on a daily basis is decided by VLPJSC. Obviously as a private company it has a strong incentive to operate the project as efficiently as possible, which means as close to the best operating point as possible to maximize annual energy production.

Nevertheless, it does seem that the operating strategy in 2017 was not constant throughout the year: as shown in Figure 11-55, in January to June the operation reflects daily peaking operation, but with flat output during the peak hours. However in the wet season, the output during the peak hours suggests load following (and with very little generation at night).



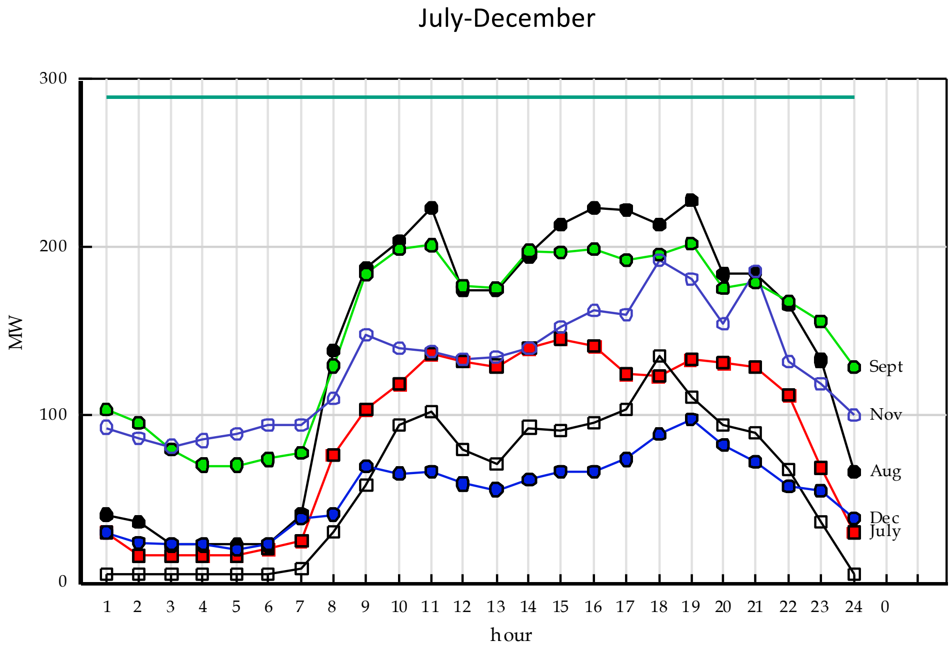


Figure 0-55. Average monthly generation, by hour of the day.

Superimposing solar PV

Figure 11-56 shows the hourly output of a 10 Wp PV facility at Xe Kaman 1. The great hourly variation is what gives rise to concerns about impact on the stability of the grid.

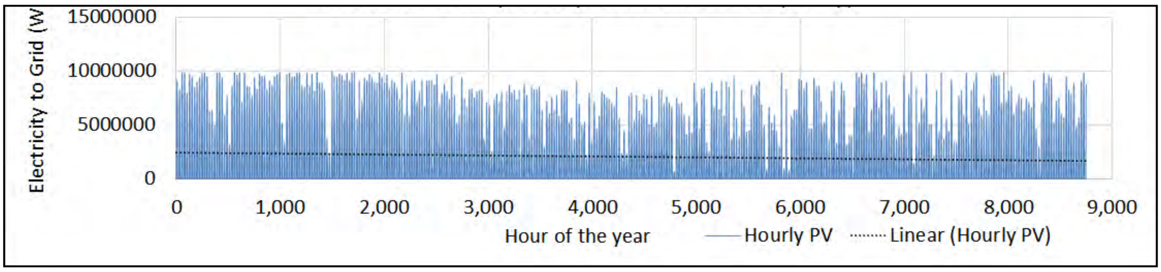


Figure 0-56. Xe Kaman 1 Solar power (for 10 Wp installed capacity).

The corresponding monthly averages, by time of day, are shown in Figure 11-57. The seasonal variation is striking – in June the maximum output of the nominal 100 MWp is just slight above 60 MWp, compared to almost the full 100 MWp in February.

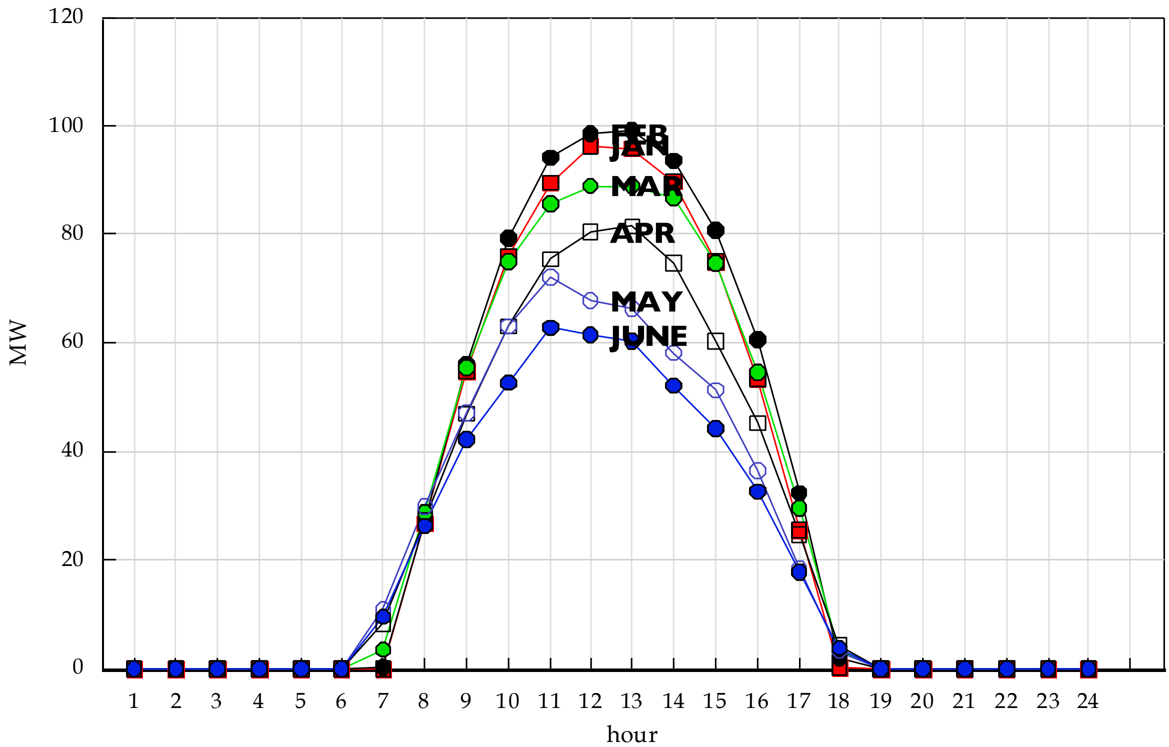
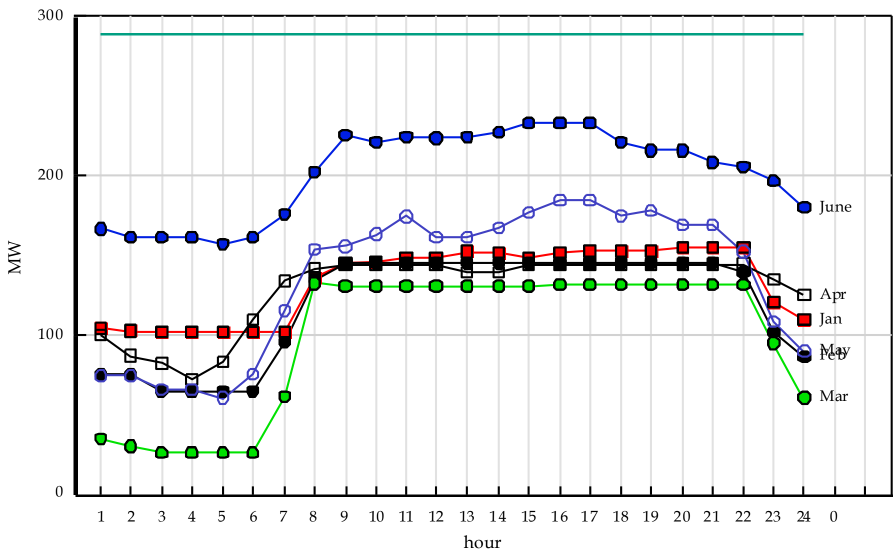


Figure 0-57. Average solar output, 100 MWp project.

Figure 11-58 shows the impact of superimposing the pV output onto the hydro generation, again as an average for the hour of the day in each month. The constant output during peak hours is now displaced by the natural variation of the PV – assuming no adjustment to the hydro production.

No PV



with PV added

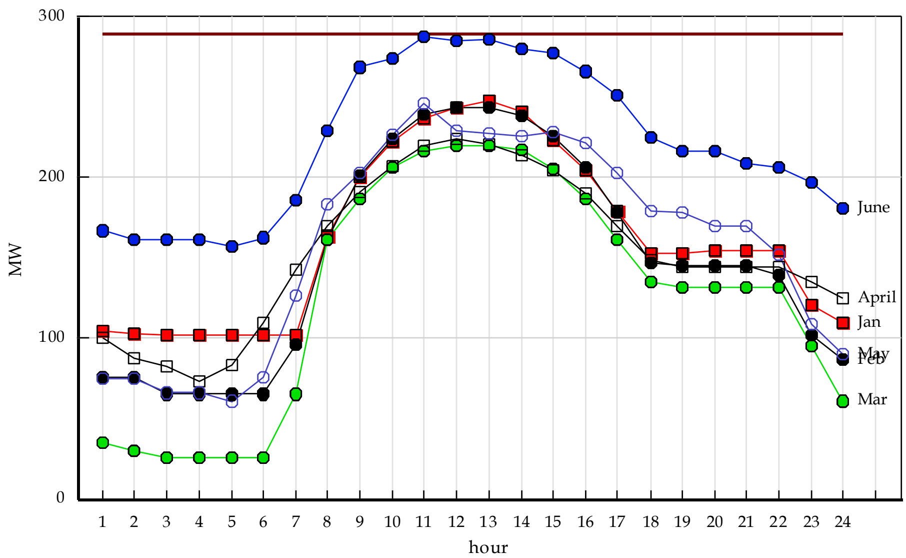


Figure 0-58. Superimposing PV output.

Figure 11-59: shows operation of the project on the three-day period May 25-27. Figure 11-59A shows actual dispatch of the two hydro units on these days. 11-59B shows the corresponding PV output, and 11-59C the combined joint output.

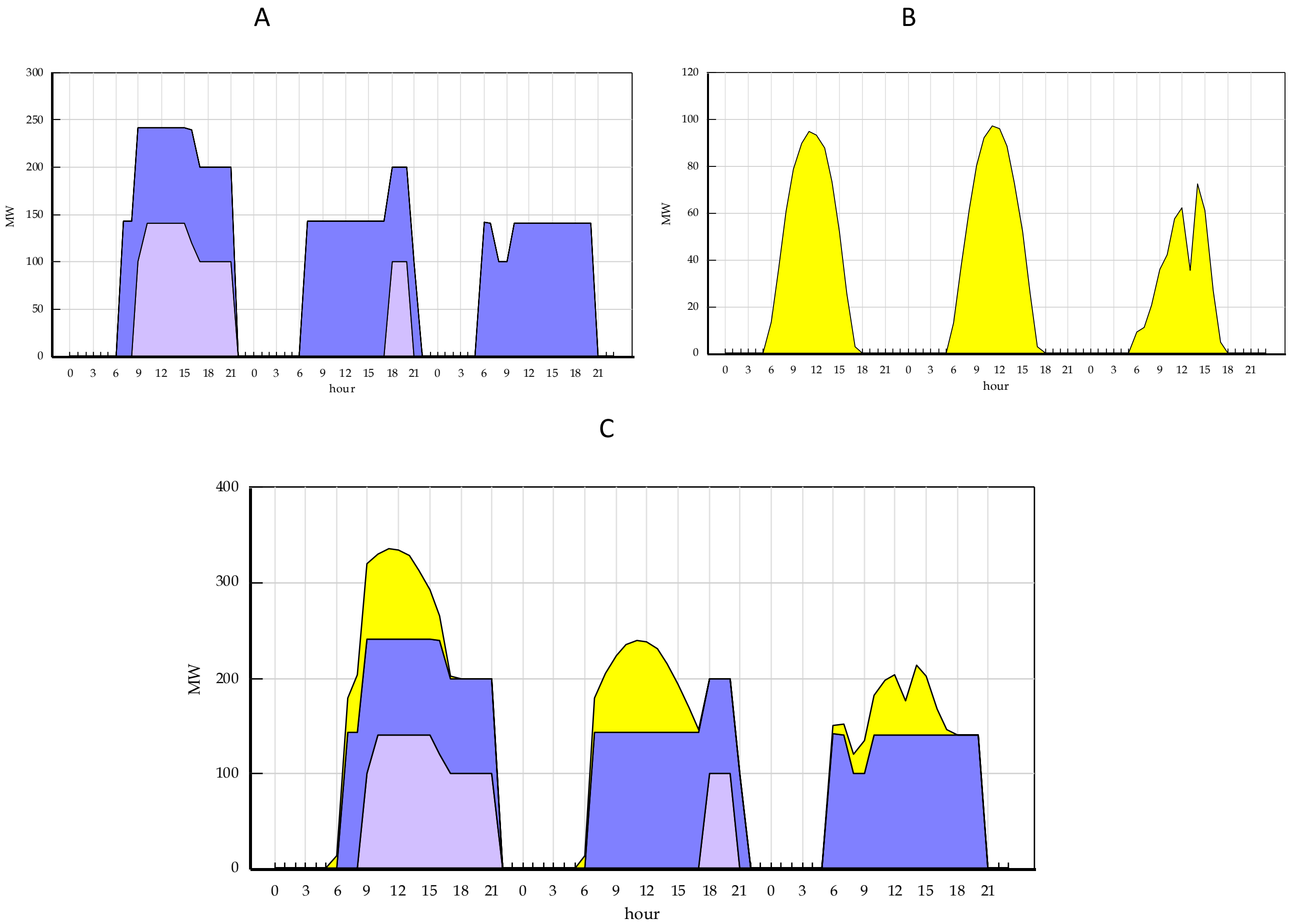


Figure 0-59. (A,B, C) Xe Kaman 1 Operations 25-27 May 2017.

The question is whether the hydro output would be adjusted rather than simply adding the PV output on top of the normal hydro dispatch. This might be necessary if there were a transmission constraint, though the power systems modeling shows that as much as 400 MW of PV could be accommodated without upgrading the existing transmission line.

Whether the adjustment is worth making depend on two factors: the loss of efficiency, and the relative remuneration for solar and hydro. The first is that if the hydro units are ramped down, there will be a loss of efficiency, since operation of the turbine that is ramped down will decline as it is pushed off the BOP. This is illustrated in Figure 10-60: a ramping down from 145 to 95 MW will cause the efficiency to drop from 96 to 92%.

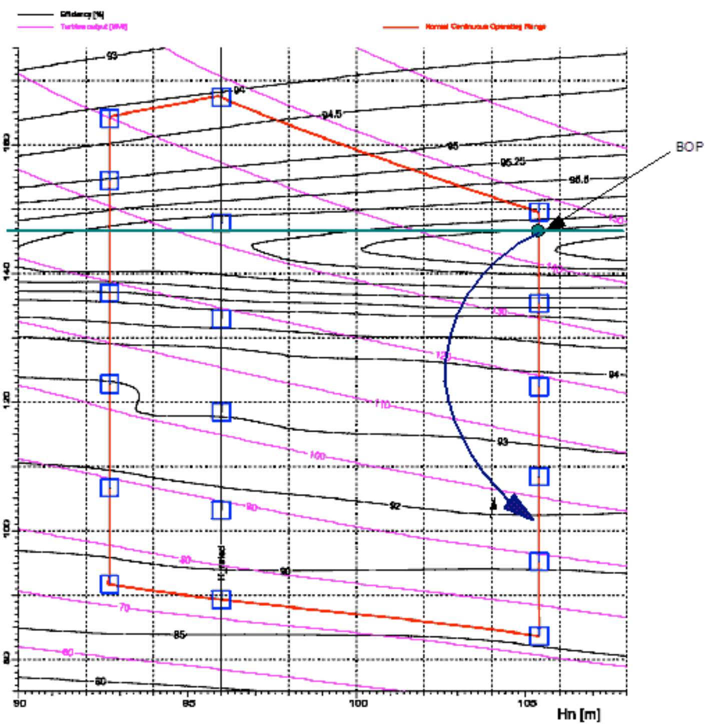


Figure 0-60. Loss of efficiency when ramped down from 145 to 95MW.

Whether this loss matters depends on the relative tariffs. If the PV energy is remunerated at several USc/kWh more than hydro, then it may well be financially advantageous to ramp down the hydro rather than curtail the PV (since a kWh of PV is worth more than the kWh of hydro as may be lost due to lower efficiency).

Figure 11-61 shows operations at Xe Kaman on 31st January-2nd February – with a very different pattern of output of the hydro project at a constant 145 MW throughout the day. The obvious adjustment to the unadjusted combined output of Figure 11-61C is shown in Figure 11-61D – in which the hydro turbine is ramped down and up to provide a similar constant output as was actually delivered – except that the output is now 185 rather than 145 MW on the first two days, and 184 rather than 145 MW on the third day.

Whether the adjustments shown in Figure 11-61D , which appear to be on a set of sunny days, could actually be made as shown depends on the ramp rates of the turbines. VPLJSC has reported average rates up and down of around 9.7 MW/minute for each unit.

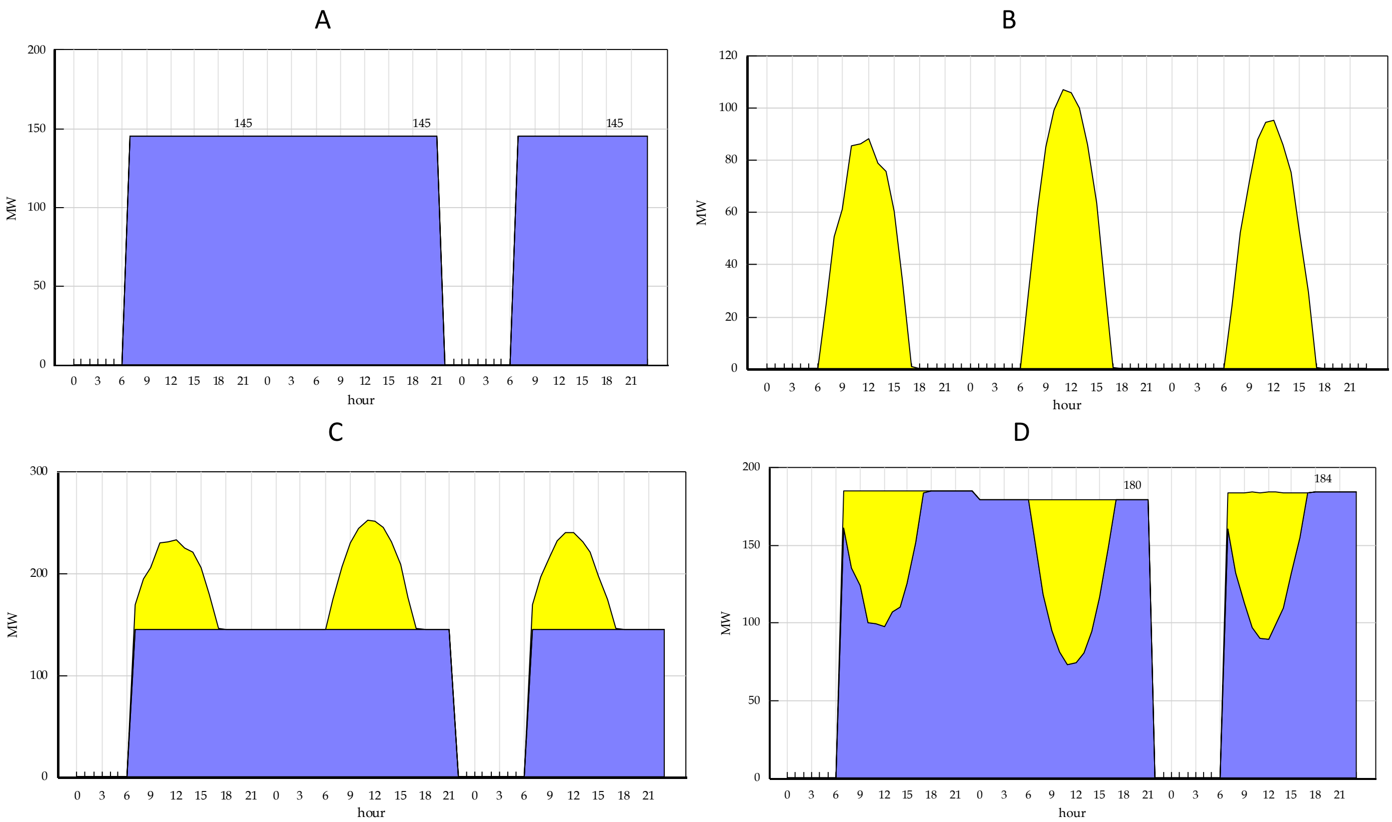


Figure 0-61. (A,B, C, D) Xe Kaman 1 Operations 31st January-2nd February 2017.

A rough order of magnitude estimate of the change in solar output for a 100MWp PV project would be from 0 to 100MW over six hours, namely 100/6/60 = 0.278MW per minute, well below 9.7MW/minute, and well below the range of lowest ramp rates observed. In other words, on cloudless days, there is no problem in adjusting hydro output to changes in solar output, making the solar energy fully dispatchable (provided the reservoir is not in spill condition – which was the case throughout 2017). Figure 11-62 shows the ramp rates for the solar on these three days compared to the maximum 9.7MW/minute.

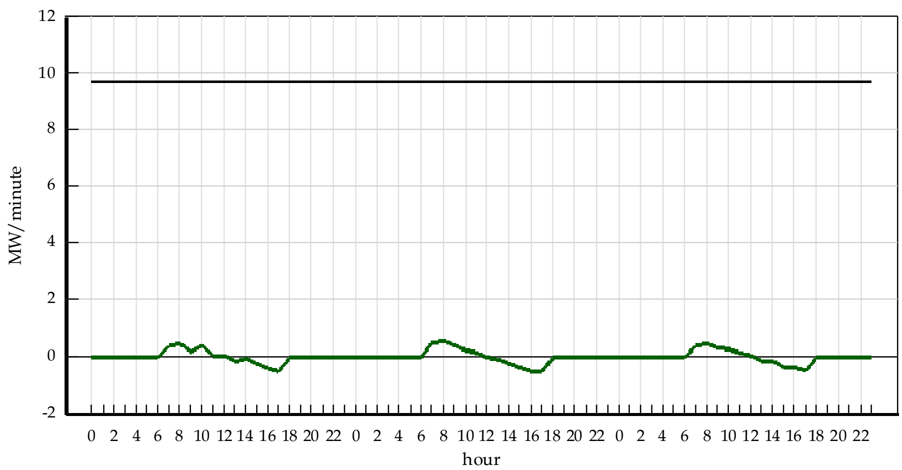


Figure 0-62. Ramp rate comparison, 31st January-2nd February 2017.

On cloudy days the situation is rather different, because the ramp rates of the solar PV will be much greater as intermittent clouds pass over the panels. For a detailed feasibility study one will need to examine solar data of at least 5-minute intervals.

How much PV can be installed at Xe Kaman 1?

In theory, one could install as much floating PV on the Xe Kaman Reservoir as there is reservoir surface area available, subject only to the following limits:

- The transmission evacuation capacity – though the transmission line can always be upgraded (at a cost), as noted in the PSSE modeling results.
- The ability of the EVN grid to absorb short-term fluctuations- though this can always be mitigated (at a cost) by storage batteries or flywheels.
- Environmental limits – there would likely be limits as to how much of the surface area one can cover before there may arise questions regarding water quality, the eco-system, and the impact on any reservoir fisheries. But even coverage of only 10-15% of the total water surface area would in principle allow more than 1,000 MW

From the hill chart we observe that the minimum operation of the hydro project is around 73 MW – meaning that the range that the hydro generation can be ramped down is between 73 MW and 290 MW (two units running at design discharge). It necessarily follows that the maximum PV that can be made dispatchable by ramping down of hydro units is 217 MW, so about two thirds of the installed hydro capacity. We observe at Longyanxia a PV capacity of 850 MW for a hydro capacity of 1280 MW – again PV is almost precisely two thirds of the hydro installed capacity.

With Xe Kaman representing a small contribution to the very large installed capacity of Vietnam, the ability to make a few hundred MW of solar PV dispatchable may not be as pressing as it would be in the case of smaller grids (as for example PV at the LSS2 project in Cambodia). Indeed, according to the latest revision of EVN's 7th Power development Plan, Vietnam plans some 12,000 MW of solar PV by 2030.

The immediate advantage of PV at Xe Kaman 1 is that no land needs to be acquired, and that the transmission line has excess capacity – neither of which holds true for other PV projects being planned in Vietnam. One may therefore conclude that a PV project with a first phase of 200 MW, followed by a second phase of another 200 MW should be the subject of a detailed feasibility study. Once the concept has been proven, and 400 MW absorbed by the EVN grid without difficulty, one may then examine the feasibility of additional tranches as may require transmission line upgrades or additional evacuation capacity (perhaps involving other hydro projects in Laos as well).

Conclusions on hybrid PV-hydro operation

Many of the questions raised in this analysis can only be answered by the construction of a more detailed optimization model that would need to be constructed as part of any detailed feasibility study, and that certainly lies outside the scope of this NHI report. The optimal strategy would also depend on the negotiated price for the PV, and by how much it differs from the hydro tariff. Indeed there are questions as to whether the present Vietnam solar PV feed-in tariff would apply to solar power generated in Laos. Moreover, the Government of Vietnam is also considering whether to move from FIT to auctions for PV projects: for a hydro operator to consider a bid under such a competitive regime he would certainly need to have such an optimization model at hand.

Even if several hundred MW of PV were added at XK1, this would still represent a relatively small project by the standards of the Vietnamese grid, so its output fluctuations may well be of little concern to EVN- unlike the situation in both Laos and Cambodia, where the grids are still quite weak and likely to be so for another decade or so, and which would limit the potential for larger PV projects.

But with the cancellation of the nuclear project in Vietnam, and the pressure to eliminate the many planned coal projects in favor of gas, the need for additional power in Vietnam by the mid 2020s, and the opposition to large Mekong mainstream projects, the appetite for adding larger amounts of PV energy will inevitably grow.

Moreover, as was noted in Figure 11-14 , the seasonal distribution of solar PV is such that its highest output is in the dry season. While this is not an issue for a project with as large a storage as at XK1, from the perspective of the grid that has much run-of-river hydro, dry season energy is at a premium (indeed the Vietnam avoided cost tariff for renewable energy provides a significant premium for dry season peak hour power, and therefore the ability to shift the solar energy output to the peak hours at a hybrid PV-hydro project is of significant value to the grid – even if not remunerated in the form of a time-of-day or seasonal tariff).

Next Steps

We recommend that a detailed FS be prepared by VLPJSC. The following require special attention:

(1) Consultants need to be engaged with the necessary engineering expertise to make decisions on the design of the floating structures, with particular reference to any logistical issues to assemble these on site, and to advise on the costing and procurement of the various components.

(2) On technical matters, solar PV data with at least 5 minute time-steps needs to be studied to determine likely ramp rates. At larger scales of implementation, it may be desirable to site floating panels at dispersed locations on the reservoir: while this may involve higher cabling costs to connect more distant floats, this may be offset by the smoothing effect of dispersed siting.

(3) On the benefit side a reservoir operations and optimization model needs to be constructed to identify the degree to which additional benefits can be obtained by integrated operation, and to demonstrate how PV production serves as a hedge in dry hydro years. This would underpin arguments for a higher tariff for solar PV than for the existing hydro.

(4) Once this is at hand, discussions should be held with EVN and the Governments of Laos and Vietnam on the options for commercial arrangements, and the issues surrounding the PPA. Several issues need resolution (such as whether the announced FIT would apply to Xe Kaman 1, and how the additional solar output would be shared with Laos).

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 Laos – 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. In the case of PV evacuated into the EVN system of Vietnam (as would be the case at Xe Kaman 1), the potential demand in Vietnam is so large that annual increments of 500 MW could easily be accommodated.

- 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 Francis turbines at XK1 cannot absorb short-term output fluctuations, reactive compensation and – as last resort - battery storage systems will be able to mitigate this impact at relatively small incremental cost.

- From the initial PSS/E modeling for load flow between XK1 and Pleiku 2, it can be derived that an almost ~400 MWp of additional Floating PV can be accommodated on the existing 666 MW transmission line, which increases to almost ~500 MWp in case the line is upgraded to 800 MW.

- A floating PV system at XK1 can be added without in any way detracting the ongoing hydro operations. Given the strong interest of the present operator/owner of XK1, 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 XK1. However, engineering solutions are available to mitigate this risk.

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ANNEXES

Annex 11.1:

The Longyangxia Hybrid Hydro/Solar Power Station in China

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General Information

The Longyangxia hydro Solar Power Station is the largest hybrid hydro-solar power station in the world and located in Qinghai province China. The power station consists of Longyangxia hydropower station and Gonghe solar photovoltaic station.

Longyangxia hydropower station was initially commissioned in 1989, which installed 4×320MW generation units with a total installation capacity of 1280MW. The designed yearly average energy generation is 5.942GWh, annual utilization hours of installed capacity is 4642h.

Longyangxia hydro dam is located at the entrance of the Longyangxia canyon on the Yellow River in Gonghe County, Qinghai Province. It is a carryover storage with excellent multi-year regulation capability. The designed normal storage water level is 2600m and dead water level is 2530m, the regulation storage is 193.5×108m^3, regulation storage ratio is 0.94.

Longyangxia Hydropower station is the first cascaded project on the main reach of the upper part of the Yellow River. It has comprehensive functions, such as power generation, flood control, ice control and irrigation. It also is the first load peaking, frequency regulation power plant in electric network in Northwest China. The hydro power station was integrated into power grid through a 363kV substation, which is equipped with 6 incoming and outgoing line bays. 5 of them are in use and 1 is reserved.

The Gonghe solar station is 30km away from the Longyangxia hydro power station. It was first built and commissioned in 2013 with a nameplate capacity of 320 MWp (Phase I), covering 9 km2 area (ground-mounted). The designed yearly average energy generation of phase I solar station is 0.498GWh, annual utilization hours of installed capacity is 1556h. An additional 530 MWp (Phase II) was completed in 2015, which covering further 14 km^2. The solar power station is directly connected to the reserved line bay inside the Longyangxia hydro power substation by a 330 kV transmission line.

Complimentary Operation Scheme of Hydro-Solar Power Station

Longyangxia hydro-solar complimentary operation system is the core control system of the power station. In this system, the solar power station is treated as an additional non-adjustable generation unit of hydro power plant. The grid dispatcher only sent a desired total output curve to the power station through AGC system. The desired output curve has to be adjusted everyday according to daily load, solar and water conditions.

The hydro-solar complimentary operation scheme is proposed as follows: hydropower and solar power are treated as one generation source. The solar power is compensated by the hydropower: the hydro power will reduce its output by retaining the water in case of high solar output power; In case of low solar output, the hydro power will increase its output. The base load and maximum load of the hydro-solar power station remains at 200MW and 1000MW, which is the same as before complimentary operation. The following section explains the detailed complimentary operation under different water and season conditions.

The water inflow of Longyangxia hydro power station is at minimum level from November to April.

It gradually increases from May and reaches maximum in July. After that it gradually reduces again. The operation of Longyangxia hydro power plant before the complimentary operation followed the water characteristics of the river. Figure 36 shows the average daily operation curves of the hydro power plant before complimentary operation. The output power at late July and August are always maximum due to the excess water flow. The figure also shows that the hydro power station undertakes some base load. The daily lowest loading happens at 4-5am, the maximum loading happens at 7-9pm. Table 6 shows the average daily output from Gonghe solar power station (phase 1).

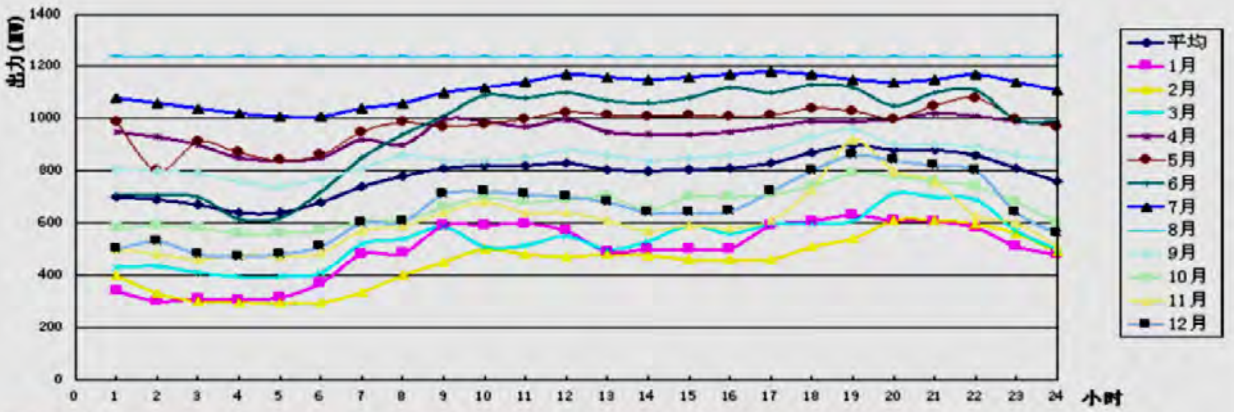

Figure 36 monthly average and annual average daily operation in Longyangxia hydropower station

Table 6 Statistics of average daily output in photovoltaic power station (Phase I, MW)

	Jan	Feb	Mar.	April	May	June	July	Aug.	Sep	Oct	Nov.	Dec.
Daily max average output	79.2	88.2	84.2	81.5	77.2	81.5	76.4	76.4	77.4	68.6	78.4	69.2
Daily min average output	30.7	31.9	14.3	36.2	15.8	14.0	13.1	10.1	11.5	18.3	42.7	32.8
Daily average	61.6	64.9	62.7	59.4	56.3	48.5	51.0	53.6	52.5	49.9	63.7	59.1

Figure 37 and Figure 38 shows the proposed daily output curve before and after complimentary operation in July and December in a dry year. It is seen that the base load and the maximum load taken by the complimentary system remain the same as before, which is 200MW and 1000MW. After complimentary operation, the daily output curve from hydro power is different, but the total energy generated by hydro remains the same as before. Therefore, the reservoir water balance is maintained the same as before.

Figure 39 and Figure 40 compare the total system output and hydro output before and after complimentary operation in July and December (dry year). Both months the total output power is increased after complimentary operation, especially during morning peak in December. At the same time, the output from Hydro is reduced. The saved energy from hydro during peak hours is then used during early morning and late night.

Similar Figures are also shown for a wet year. In July, due to the excess water flow, the hydro output is at maximum level for a whole day. Complimentary operation between hydro and solar is not possible. If the system cannot absorb the excess power from solar, either water "spill" or solar curtailment will happen. In December, the power station can maintain complimentary operation, the minimum and maximum loading remain the same as before.

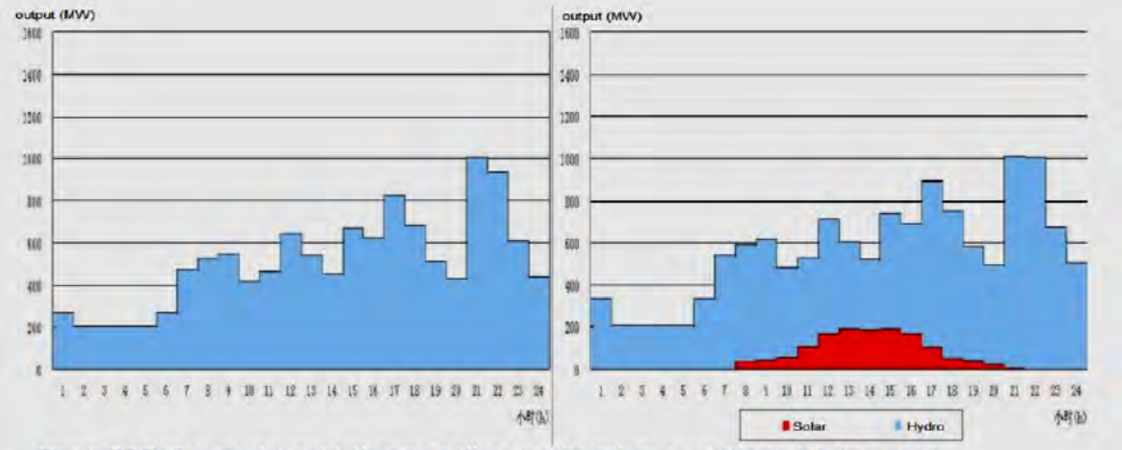

Figure 37 Daily output curve before and after complimentary operation in July (dry year)

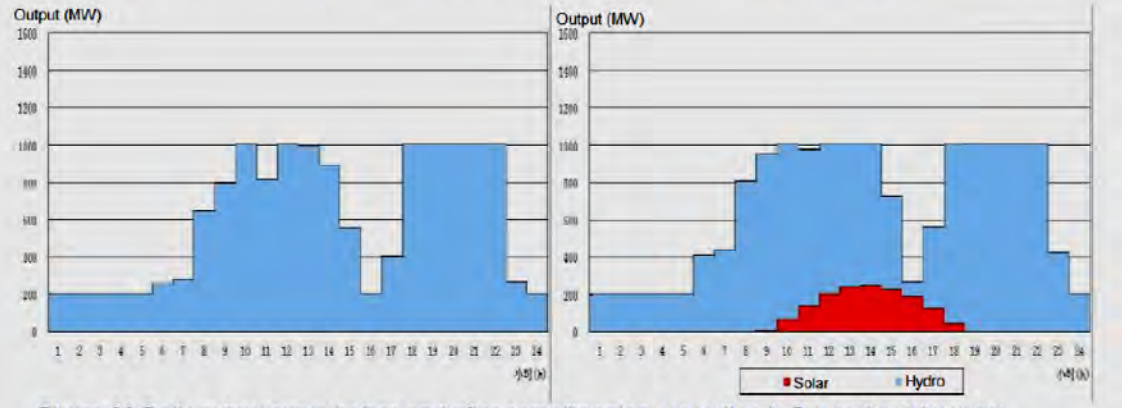

Figure 38 Daily output curve before and after complimentary operation in December (dry year)

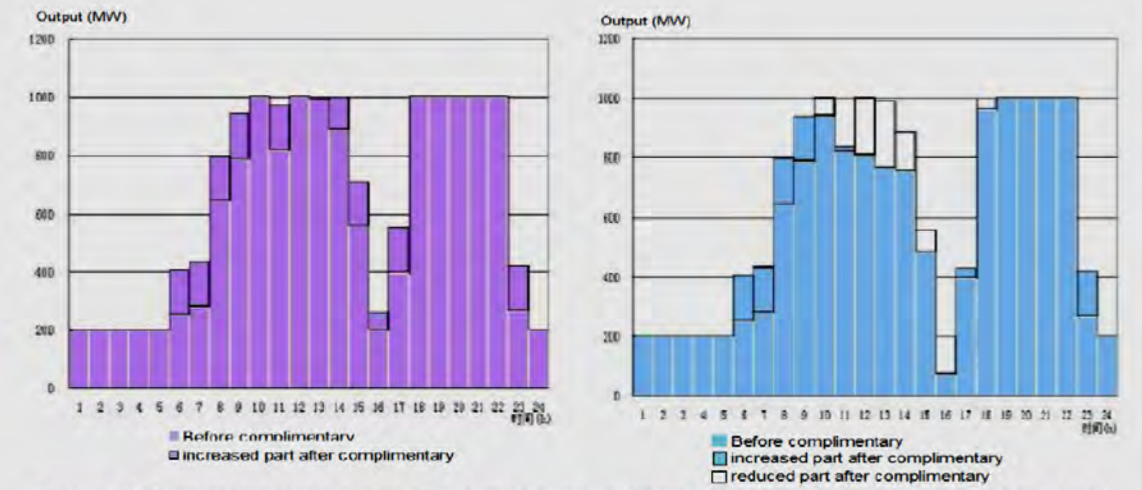

Figure 40 Comparison before and after complimentary operation in December (Dry year). Left: total system demand; Right: output from Hydro

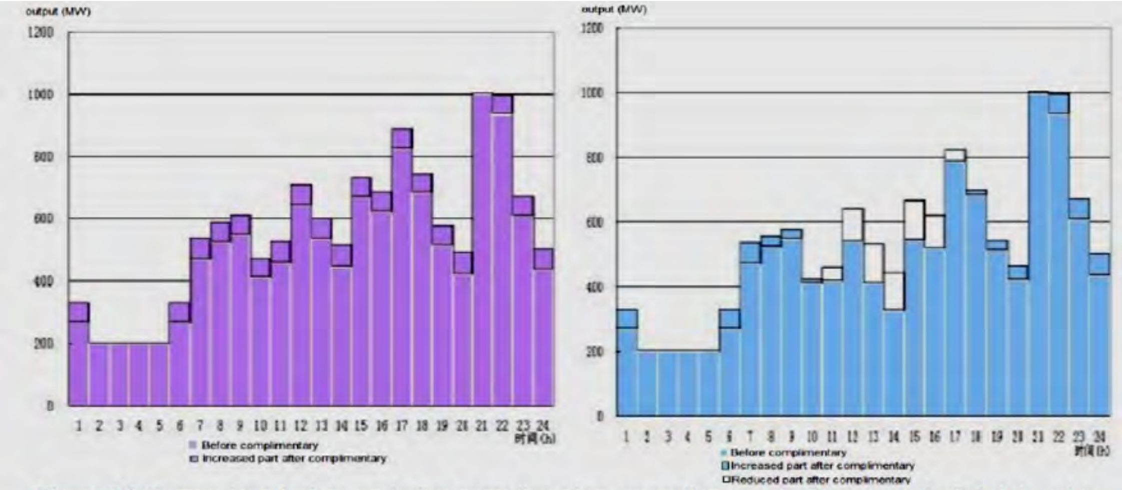

Figure 39 Comparison before and after complimentary operation in July (Dry year). Left: total system demand; Right: output from Hydro

AGC Control Principles and Rules

AGC system can dispatch active power to each unit inside Longyangxia power station. The major objectives include: (1) Smooth the solar power variations in a fast and effective way; (2) meet the grid active power set point; (3) minimize the active power adjustments of hydropower units to avoid wear and tear.

The AGC active power dispatch principle is explained as follows:

• In case of the total active power set point *increasing*, increase the hydro unit with the minimum utilization factor first. The dispatch is finished by only adjusting one unit if the following conditions are fully met:
(1) the increment is less than the adjust step of the unit;
(2) after active power increase, the unit will not enter vibration region;
(3) the actual output will not exceed the unit maximum power limit. If either condition cannot be met, AGC will continue to dispatch the next unit until the incremental active power are totally dispatched.
The same dispatch principle will follow.

• In case of active power *reducing*, the first unit to reduce power is the one with the maximum utilization factor. The dispatch principles are the same as power increasing.

Other rules AGC should follow are:

1) Hydro generators should not operate under vibration region;
2) Avoid crossing vibration region frequently;
3) In case the active power set point is higher than actual output, avoid reducing hydro generation loading as much as possible; in case of active power set point is less than the actual output, avoid increasing hydro generation loading as much as possible;
4) Hydro generator output power should not be regulated frequently;
5) Treat solar power station as a non-regulated virtual unit of hydro power station;
6) Pre-defined active power step for each unit.
7) Set dead band for sola

Source:

Floating PV feasibility study at LSS2
— Progress report for Task Order #1
Report prepared for
Natural Heritage Institute
by
Solar Energy Research Institute of Singapore (SERIS)
Authors: Dr. ZHAO Lu, Head of PV System Technology
Dr. ZHAN Yanqin, Senior Research Fellow, PV Grid Integration
Dr. Thomas REINDL, Deputy CEO, SERIS
Jun 20, 2017

Annex 11.2:

Detailed Results of the PSSE System Simulation Studies

Annex 11.2: Detailed results of the PSSE system simulation studies

1. Introduction

This Annex presents the details of the PSSE studies summarised in the Main report. Three main issues are examined: transmission line constraints; additional reactive compensation devices, and grid stability concerns.

2. Project Overview

Xe Kaman#1 Hydropower project was built in the downstream of Xe Kaman river, containing 2 subprojects: Xe Kaman#1 hydropower plant in the upper section of the river and Xe Kaman Sanxay hydropower plant in the lower section. The Project is located in both Sanxay and Sayxetha districts, Attapeu province of the Lao PDR. It is about 80 km away from Vietnam-Laos border. The transmission system in the area is shown in Figure 11.2-1.

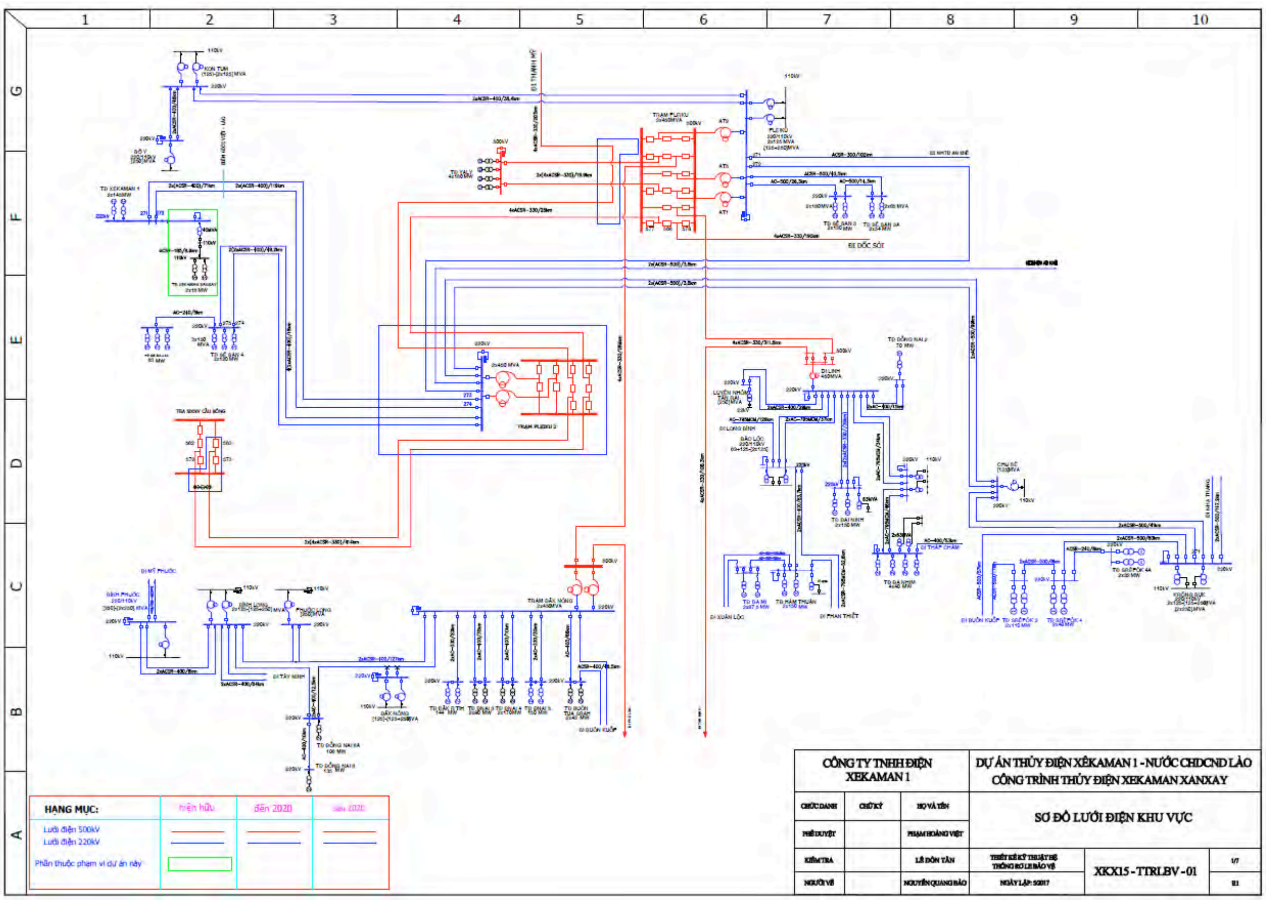

Figure 11.2-1. Transmission system single line diagram near Xe Kaman#1.

Xe Kaman#3 hydropower is located in Dakcheung district of Xekong province in the southern part of Laos, which is about 70km from Xekamn#1. The general information of Xe Kaman#1, Xe Kaman Sanxay and Xe Kaman#3 hydropower are listed in Table 11.2-1.

Table 11.2-1. General information of Xe Kaman#1 hydropower plant

Name	Capactity (MW)	Commission year	Annual generation (GWh)	Gross volume of reservoir ($10^6 m^3$)
Xe Kaman#1	2*145	2011	1100	4800
Sanxay	2*16	2017	123	8.65
Xe Kaman#3	2*125	-	1000	141.5

Both Xe Kaman#1 and Sanxay are connected to Xe Kaman#1 substation. All the energy generated by Xe Kaman#1 and Sanxay are exported to EVN grid 500kV Pleiku2 station through a double-circuit 230kV transmission line. Xe Kaman#3 hydropower plant is connected to EVN 500kV Thanh My substation through a double-circuit 230kV transmission line. The transmission line information is given in Table 11.2-2.

Table 11.2-2. General information of existing transmission lines

From	To	Voltage level (kV)	Conductor type	Design capacity (MW)	Max capacity can be upgraded (MW)	Length (km)
Xe Kaman#1	Pleiku2	230	Bare ACSR 400/51	666	800	190.329
Xe Kaman#3	Thanh My	230	-	300	550	80

3. Transmission line constraints

The double-circuit 230kV transmission line from Xe Kaman#1 to Pleiku2 substation is the only power evacuation path for Xe Kaman#1 hydropower plant. The line has a designed capacity of 666MW. With the additional floating PV system deployed at Xe Kaman#1, the transmission line could be overloaded and alternatively power evacuation plan should be identified.

In this section, the results of load flow study will be presented and discussed. Two simulation options has been explored in this report:

(1) Option 1: all the Xe Kaman#1 generation is evacuated through the existing transmission line from Xe Kaman#1 to Pleiku2.
(2) Option2: Additional interconnect between Xe Kaman#1 to Xe Kaman#3 substation. Currently Xe Kaman#3 substation is connected to 500KV Thanh My substation in EVN grid. With the additional interconnections, power from Xe Kaman#1 can be exported to either Pleiku2 or Thanh My substations.

3.1 Load flow results of Option 1

Figure 11.2-2 shows the load flow simulation model for Option 1. On the left side are shown the hydro units at Xe Kaman#1 and Xanxay, and the floating PV plant. On the right side, the EVN grid is modelled as an infinite bus with constant voltage.

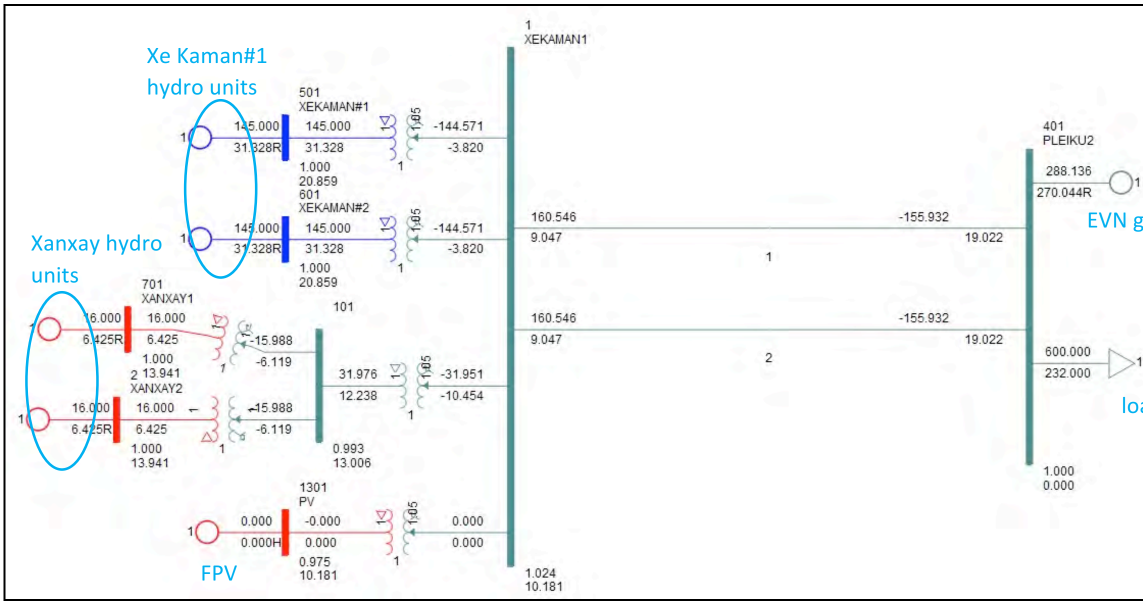

Figure 11.2-2. PV model setup for load flow study of Option 1

The system load flow studies were performed at different PV capacities. In order to reveal the worst case condition for the transmission line loading, it was assumed that both the hydro generators and PV were generated at maximum levels. The simulation results are summarized in Table 11.2-3 .

The simulation results show that without solar augmentation the maximum loading of the transmission line is 23.6%. After deploying 150 MW floating PV systems, the theoretical maximum loading could reach 35.33%, which is still acceptable. However once the installed PV reaches 400 MW, the single line loading could reach 55%. It doesn't fulfil N-1 criterion. Once the PV installation is 500 MW, n-1 criterion is no longer fulfilled even the line capacity is upgraded to 800 MW. In that condition, a new power evacuation path must be provided otherwise power curtailment would be unavoidable.

With the increasing power to be evacuated, reactive compensation devices must be provided to maintain reasonable voltage levels. Inside PV plant, the preferred reactive compensation device would be STATCOM, which could dynamically maintain voltage stability according to the PV fluctuations. Additional compensation devices could be required at Xe Kaman#1 substation when the PV installation reaches 500MW.

Table 11.2-3. Summary of load flow results of Option 1

No.	Hydro output (MW)	PV output (MW)	X1-Pleiku2 Single line loading (based on 666MVA)	X1-Pleiku2 Line loading (based on 800MVA)	Reactive power from Pleiku2 to Xe Kaman (Mvar)	Reactive compensation
Case 1	322MW (145*2+16*2)	0	23.59%	19.48%	38.044 (19.022*2)	none
Case 2	322MW (145*2+16*2)	150	35.33%	29.48%	86.28 (43.14*2)	48Mvar inside PV plant
Case 3	322MW (145*2+16*2)	400	54.95%	45.76%	297.8 (148.9*2)	190Mvar inside PV plant
Case 4	322MW (145*2+16*2)	500	62.24%	51.83%	346.9 (173.5*2)	1. 280Mvar inside PV plant 2. 150Mvar at Xe Kaman#1 s/s

The detailed load flow diagrams for the no PV and the four PV cases of Option 1 are shown in Figures 11.2- 3 to 11.2-6.

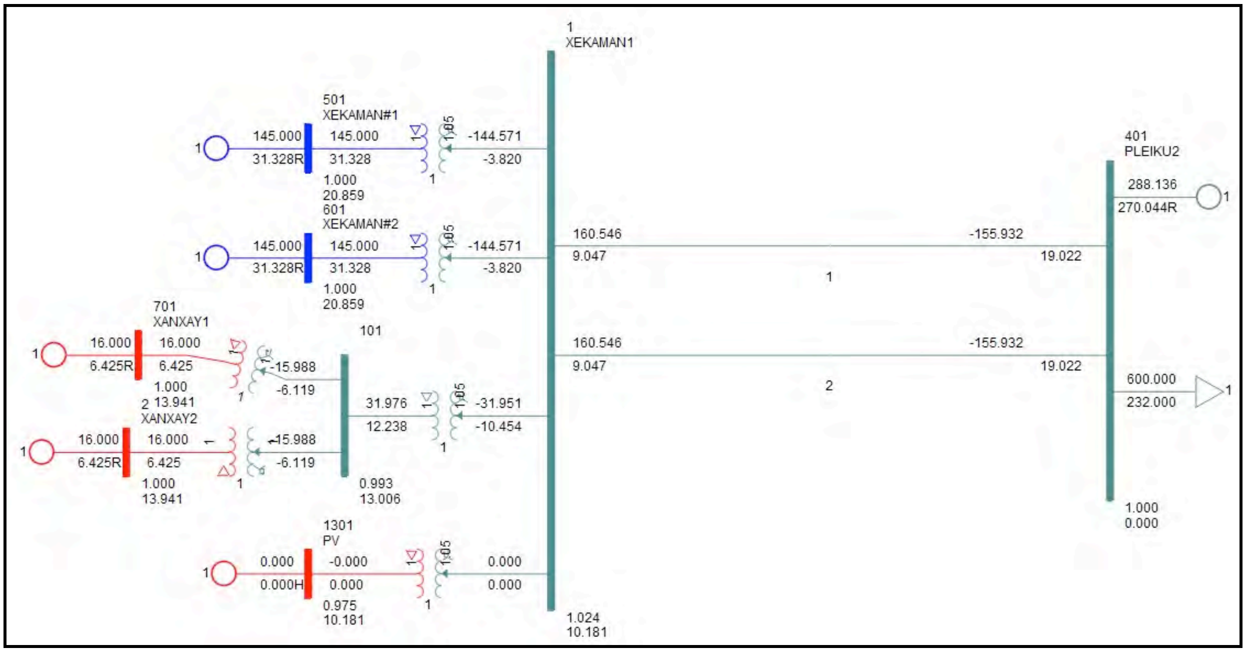

Figure 11.2-3. Load flow results without PV (Option 1)

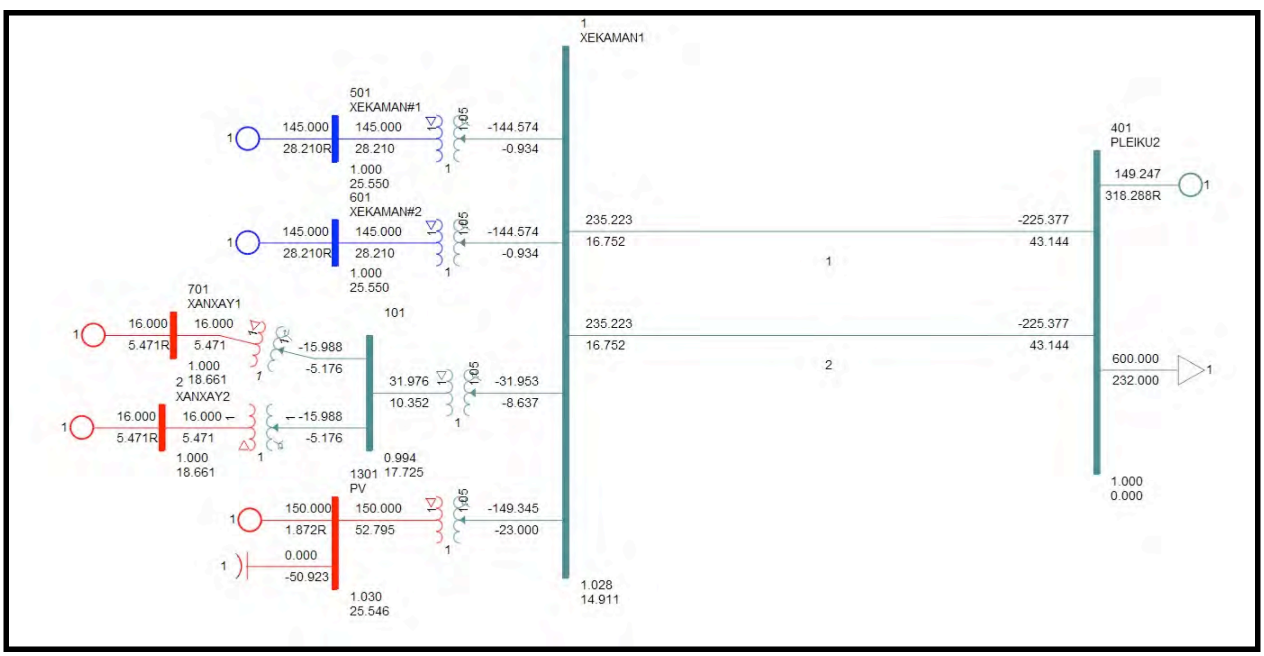

Figure 11.2-4. Load flow results with 150MW PV (Option 1)

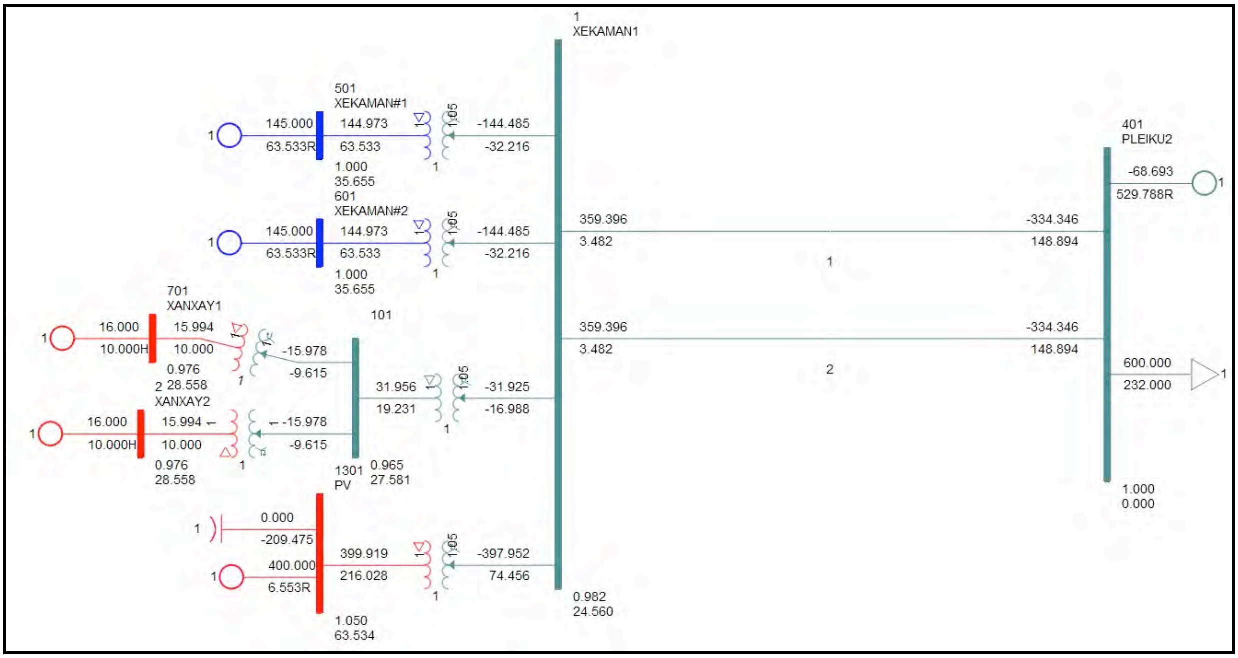

Figure 11.2-5. Load flow results with 400MW PV (Option 1)

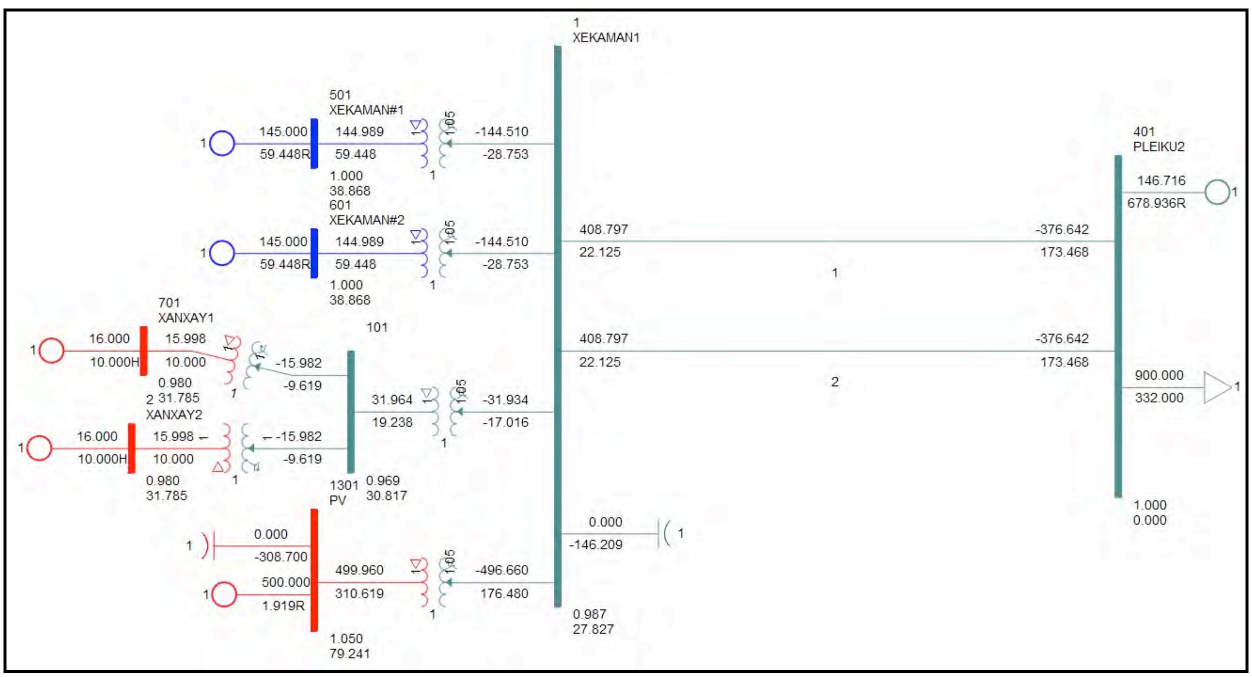

Figure 11.2-6. Load flow results with 500MW PV (Option 1)

3.2 Load flow results of Option 2

Option 2 represents a potential solution for solar power evacuation at Xekeman#1: interconnecting Xe Kaman#1 and Xe Kaman#3. Xe Kaman#3 power plant is located 70km away from Xe Kaman#1 power plant. 90% of the energy output is exported to EVN grid via an 80km 230KV double-circuit transmission line from Xe Kaman#3 to 500KV Thanh My substation.

The simulation model of Option 2 is shown in Figure 11.2-7, where the 230kV Xe Kaman#3 substation and 500KV Thanh My substation are included. It is also assumed Thanh My and Pleiku2 substations are connected through a 500KV transmission line. All the existing and planned hydropower plants at Xe Kaman basin are included in the simulation. The simulation results are given in Table 11.2-4, and the associated load flow result figures are shown in Figures 11.2-8 to 11.2-12

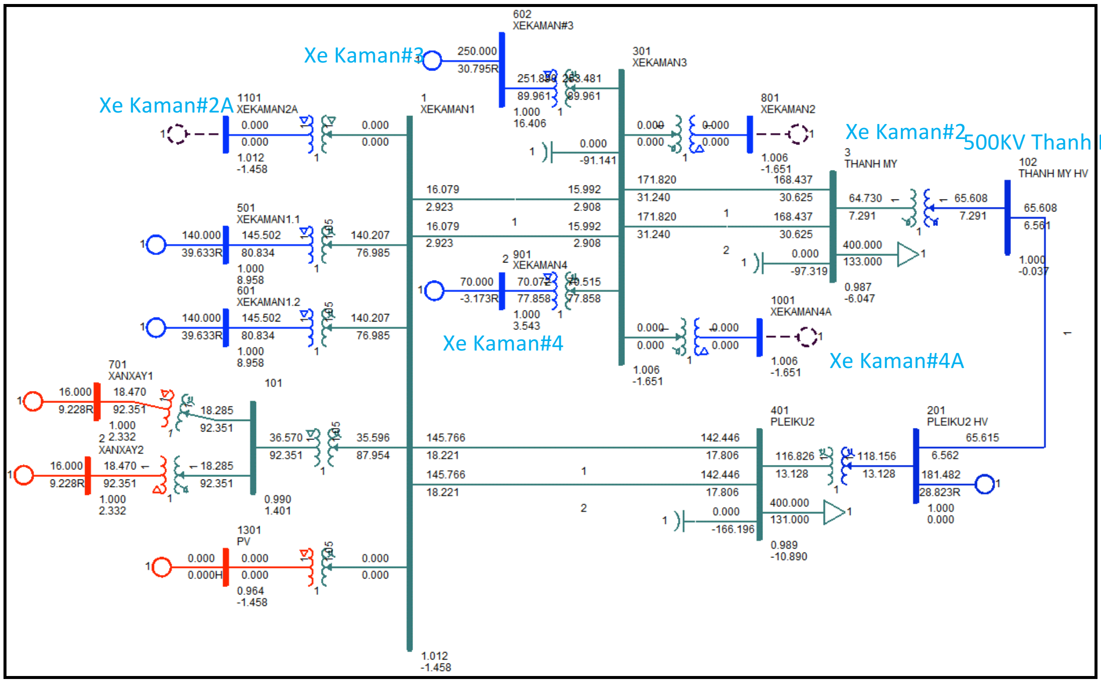

Figure 11.2-7. PV model setup for load flow study of Option 2

For case 1 and case 4, only the existing and under-construction hydropower are considered in the simulation, which are Xe Kaman#1, Xanxay, Xe Kaman#3 and Xe Kaman#4. For case 5, all the planned hydropower plants are considered, which includes Xe Kaman#2, 2A and 4A.

The simulation shows once Xe Kaman#1 and Xe Kaman#3 are interconnected, the excess power from Xe Kaman#1 can be evacuated to EVN grid through Thanh My substation and relief the loading pressure on the line to Pleiku2. With 400MW solar PV, the loading levels on both transmission lines are below 50% and fulfil N-1 operation criterion. However if the PV installation increases to 500MW, n-1 criterion will not be fulfilled on one of the lines.

In Option 2, additional reactive compensation devices will be required at various substations to maintain voltage stability, which may include 230kV side of Thank My and Pleiku2 substations, Xe Kaman#3 substation and PV power plant.

Table 11.2-4. Summary of load flow results of Option 2

No.	Xe Kaman#1 s/s Hydro output (MW)	Xe Kaman#3 s/s Hydro output	PV output (MW)	X1-Pleiku2 single line loading (based on 666MVA)	X3-Thanh My Single line loading (based on 550MVA)	Reactive compensation
Case 1	322MW (X1+Xanxay)	320MW (X3+X4)	0	21.86%	31.20%	1. 90MVAr at Xe Kaman3 2. 100Mvar at Thanh My 230kV 3. 170MVar at Pleiku2 230kV
Case 2	322MW (X1+Xanxay)	320MW (X3+X4)	150	27.39%	38.16%	1. 90MVAr at Xe Kaman3 2. 100Mvar at Thanh My 230kV 3. 170MVar at Pleiku2 230kV 4. 50MVAr inside PV plant
Case 3	322MW (X1+Xanxay)	320MW (X3+X4)	400	36.47%	49.15%	1. 120MVAr at Xe Kaman3 2. 180Mvar at Thanh My 230kV 3. 250MVar at Pleiku2 230kV 4. 170MVAr inside PV plant
Case 4	322MW (X1+Xanxay)	320MW (X3+X4)	500	40.02%	53.74%	1. 180MVAr at Xe Kaman3 2. 250Mvar at Thanh My 230kV 3. 300MVar at Pleiku2 230kV 4. 270MVAr inside PV plant
Case 5*	386MW (X1+Xanxay+2A)	493MW (X3+X4+4A+2)	500	48.46%	65.18	1. 240MVAr at Xe Kaman3 2. 300Mvar at Thanh My 230kV 3. 380MVar at Pleiku2 230kV 4. 270MVAr inside PV plant

There is also a discussion of the extreme condition to deploy floating PV on 15% of the reservoir area at Xe Kaman#1. According to the reservoir information, 15% of the reservoir area will represent 1250MW of floating PV system. For such large power evacuation, a new double-circuit 230kV or 500kV transmission line from Xe Kaman#1 to EVN grid would be required.

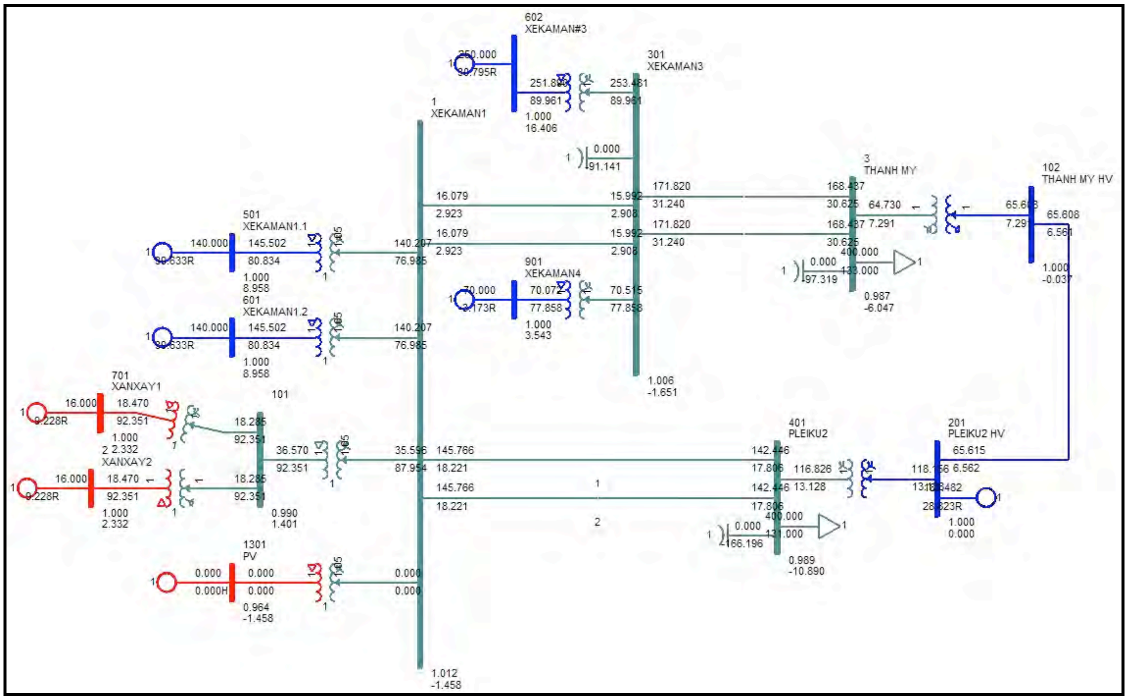

Figure 11.2-1. Load flow results without PV (Option 2)

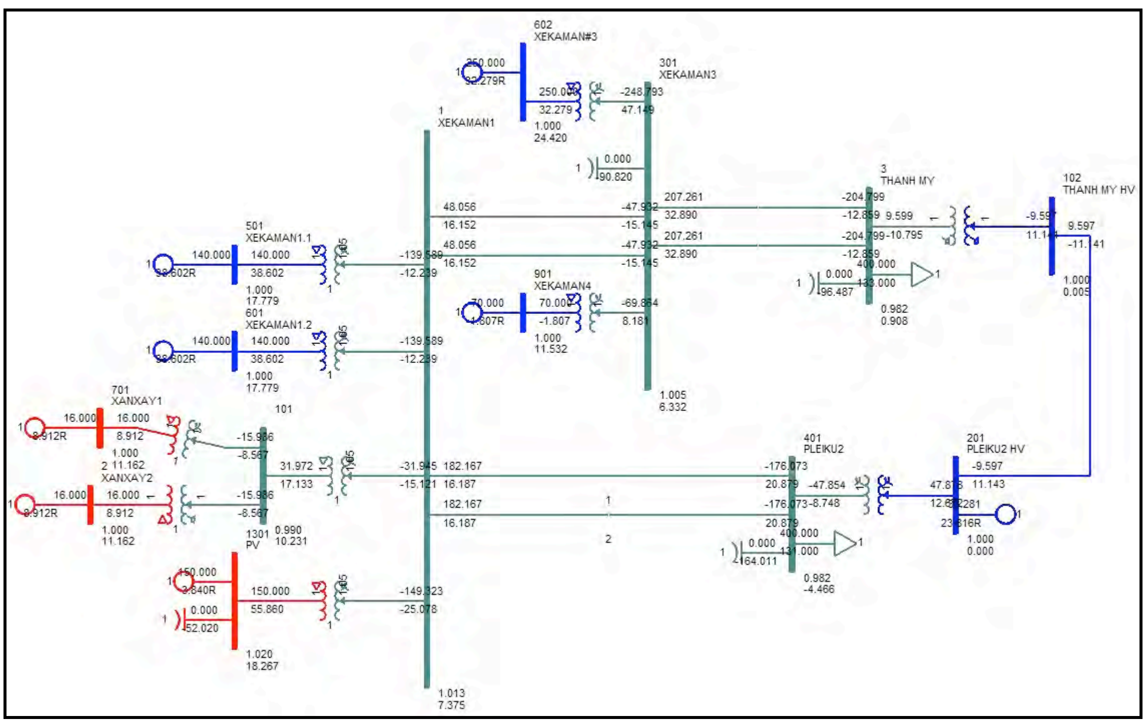

Figure 11.2-2. Load flow results with 150MW PV (Option 2)

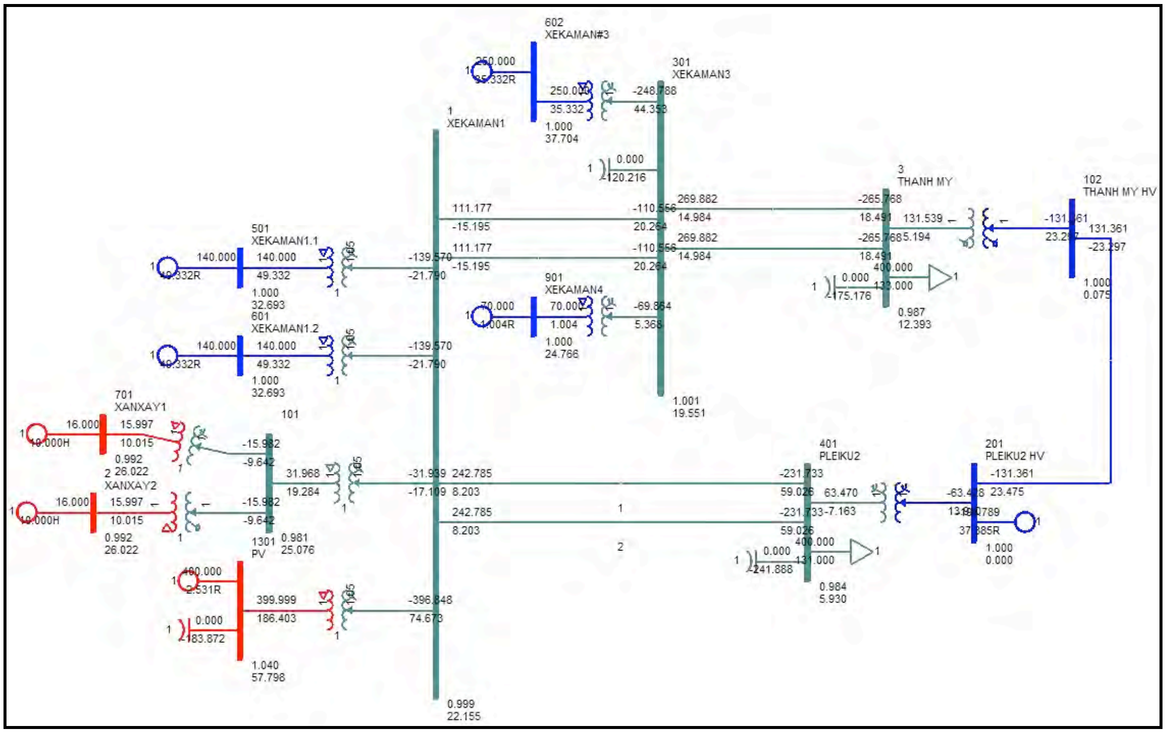

Figure 11.2-3. Load flow results with 400MW PV (Option 2)

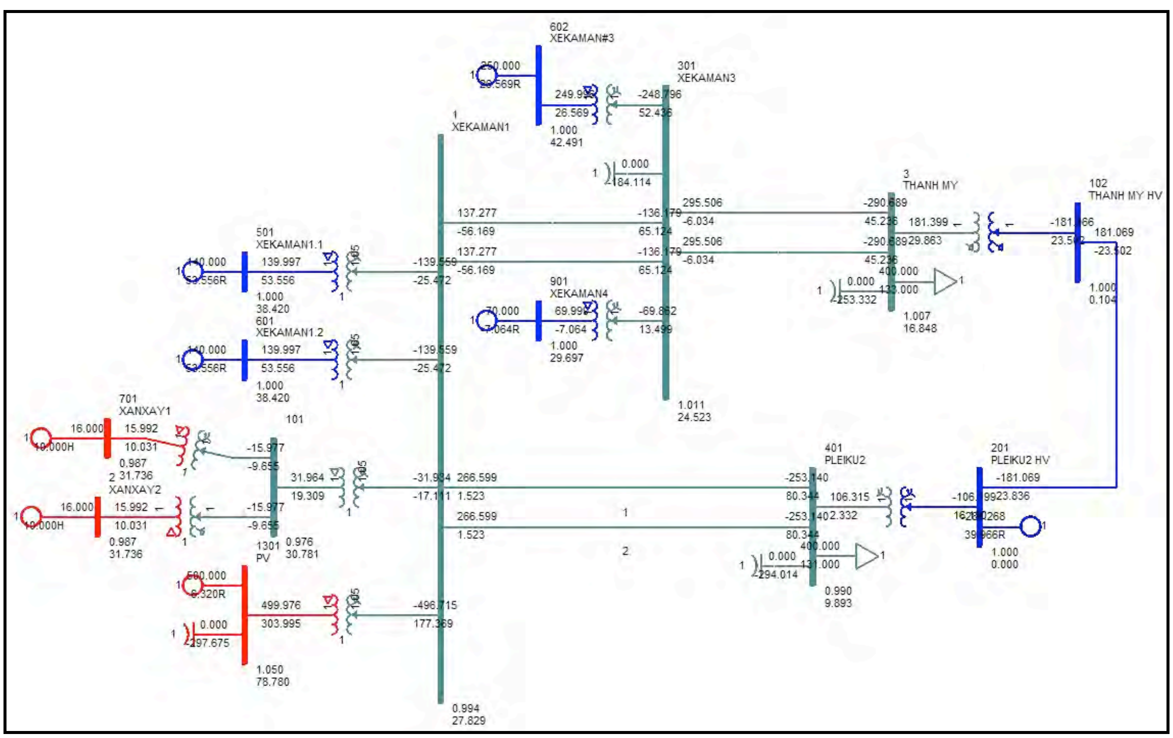

Figure 11.2-4. Load flow results with 500MW PV (Option 2)

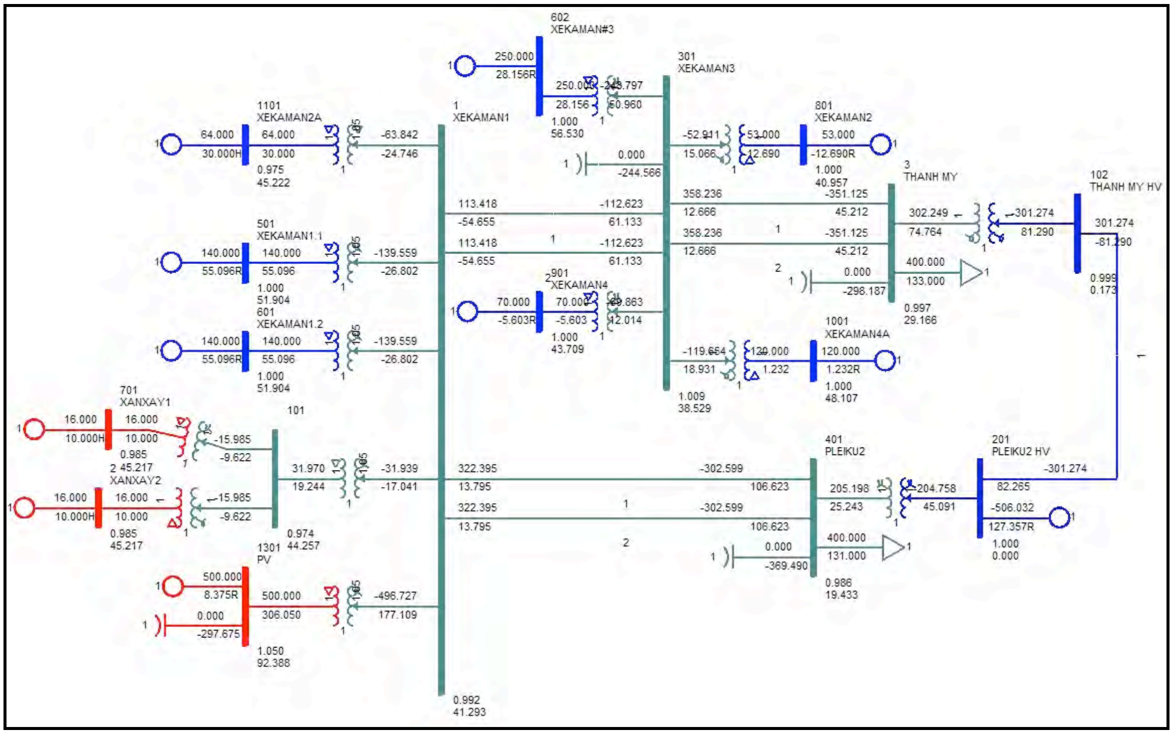

Figure 11.2-5. Load flow results with 500MW PV and planned hydropower (Option 2)

4. Grid stability impact due to PV Fluctuations

A key concern of large scale grid-connected PV system is the short-term power fluctuations due to moving clouds, which may lead to large power ramp-rates and cause voltage and/or frequency fluctuations to the grid. For Xe Kaman#1 solar augmentation project, PV fluctuations should not be treated as a major concern to the grid stability performance. The reasons are listed as follows:

(1) The idea of hybrid operation of hydro and solar system is to minimize the PV fluctuation by regulating the hydropower, so that the total output power is smooth and predictable. From the grid point of view, the hybrid system is as dispatchable as conventional power plants. The experiences from Longyangxia project, which is the world largest hybrid hydro and solar system, show that the hybrid hydro and solar power plant is able to follow the grid dispatch curve within acceptable tolerance.

(2) EVN grid is a well-developed strong grid with interconnected transmission system. Currently the total generation capacity of EVN grid is around 42,341MW, in which over 70% are hydroelectricity and coal thermoelectricity. On the other hand, the penetration level of renewable energy such as wind and solar in EVN grid is very low. The grid has abundant resilience to handle the PV fluctuations, especially the proposed PV capacity is only around 1% of the total grid generation capacity.

(3) Due to the spatial smoothing of irradiance over large areas, the output fluctuation of a large scale solar PV power plant is significantly reduced. The solar ramp rate recorded from Longyangxia project (850MW PV) is around 1pu/15mins

Although the solar augmentation at Xe Kaman#1 will not cause primary concern to the grid stability, further investigations on the internal dynamics of the hybrid system are necessary, for example, what will be the suitable PV capacities to achieve hybrid operation with the current hydro capacity, whether the hydro turbines can provide adequate dynamic performance to smoothen PV fluctuations?

5. Conclusions

The report examined the potential power system related constraints of hybrid hydro and solar operation at Xe Kaman#1 hydropower plant. It revealed a few facts for solar augmentation project at Xe Kaman#1:

(1) N-1 criterion on the existing transmission line will be violated if the installed PV capacity reaches 400MW. One of the potential solutions is to interconnect Xe Kaman#1 and Xe Kaman#3 and use the existing transmission line at Xe Kaman#3 to evacuate excess power. However, the effectiveness of option is highly affected by the construction plan of the planned hydro power plants at Xe Kaman basin. Once solar installed PV capacity reaches 500MW, it is recommended to build new transmission lines from Xe Kaman#1 to EVN grid.

(2) Due to the characteristics of hybrid hydro and solar operation, PV fluctuations should not be a major concern to the grid stability performance. However further investigation on the internal dynamics of hybrid system is necessary.