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Techno-economic feasibility of hybrid hydro-FPV systems in Sub-Saharan Africa under different market conditions

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ABSTRACT

Floating photovoltaic (FPV) systems are an emerging and increasingly competitive application of solar PV, especially in land area-constrained countries. This study focuses on the optimal dimensioning and scheduling of a grid-connected hybrid hydro-FPV system. The case study is based on a cascade hydropower system located in Sub-Saharan Africa. The techno-economic feasibility of the hybrid system is analysed under different types of revenue streams and load commitments. Moreover, the resource complementarity between solar irradiation and reservoir water inflow in different weather years is analysed. A linear programming model for optimal dimensioning/scheduling of a hybrid hydro-FPV system is proposed. The results indicate that hybridisation with FPV can under the proposed PPA and spot market structure increase the annual producer profits by 18–21% and 0–4%, respectively compared to a hydro-only system. Furthermore, it is estimated that the CAPEX of FPV should be around 42–57% lower than that of ground-mounted PV (GPV) with single-axis tracking for the hydro-FPV system to reach the same annual producer profit as the hydro-GPV system. Considering improved efficiency by cooling the FPV modules, the revenues increase by 0–3% depending on the selected weather year and market scheme.

1. Introduction

1.1. Background

Global energy demand has been on a constant rise in the past decade, especially in developing countries [1]. A major share of this energy demand is still covered with fossil-based energy resources (e.g., coal, natural gas, and oil). Historically, the energy supply sector has been one of the main emitters of global greenhouse gas emissions (GHG) [2]. Increased concerns regarding climate change have accelerated the transition to decarbonising national energy supply sectors, especially with the integration of renewable energy sources in electricity generation. During the past decade, onshore renewable energy projects (e.g., hydropower, onshore wind power, ground/roof-mounted solar photovoltaics, and bioenergy) have been at the forefront of this energy transition [3].

Hydropower has historically dominated the renewable energy technology portfolio in many Sub-Saharan African countries [1]. Hydro-based power systems are highly dependent on precipitation and the corresponding inflow to the reservoirs. Precipitation can vary significantly between dry and rainy seasons, which can result in high year-to-year variation in hydropower generation. This variability (in combination with increased electricity demand) has led to increased dependency on thermal power plants in many African countries, further leading to increased GHG emissions [1]. Hybridisation with multi-generation systems and/or energy storage systems can reduce the uncertainties related to renewable energy generation. In this regard, different renewable energy sources can have complementary availability profiles, e.g., dry seasons can often correlate with high solar irradiation and vice versa [4]. In mid- to long-term scheduling, hybridising utility-scale solar photovoltaics (PV) with hydropower can therefore be a feasible way to reduce the seasonal variability in renewable energy generation. Moreover, in short-term scheduling, complementary operation of solar PV systems with hydropower can reduce intra-day

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operating uncertainty if PV forecast errors can be compensated for with regulated hydropower generation. This can reduce the system operating costs as deviating from load commitment is often related to cost penalty. The grid operator can also benefit from the hybrid system's reduced generation variability since it can reduce the need for operating reserves.

Utility-scale renewable energy projects can experience land-use conflicts due to the challenge of significant land-use requirements [5]. Land-use conflicts arise when new renewable energy projects compete against other land-use purposes (e.g., such as residential, recreational, agriculture, tourism etc.). Moreover, land-use conflicts can contribute to a scarcity of useable land, thus increasing land acquisition costs. This can consequently reduce the economic feasibility of the technology [6]. In this regard, floating PV (FPV) systems have emerged as increasingly competitive applications of solar PV. One of the main drivers for the rapid growth of FPV systems is the possibility to utilise unused idle spaces (e.g., hydro reservoir), especially in land area-constrained countries. The area requirement for the FPV system has reduced the visible impact and necessity for land resources [7]. Deployment of FPV systems (mainly on inland water bodies) has increased rapidly in both developed and emerging markets in recent years, e.g., in Japan, South Korea, the United Kingdom, and China where most of the FPV capacity is currently located [8]. The global capacity of FPV systems was about 2.6 GWp in 2020 [9], however, the technical potential is estimated to be significantly higher. For example, the current total reservoir surface is estimated to be about 265.7 thousand km^2 globally with a technical potential to deploy 4400 GW of FPVs at a 25% surface coverage level [10].

1.2. Literature review

Several previous studies have reported superior performance of hybrid hydro-FPV systems compared to standalone ground-based PV and hydropower, such as improved operational efficiency, energy yield, and revenues from the hybrid system operation. This is mainly due to the complementary availability of these two renewable energy sources. Moreover, the system costs can be reduced, both for the producer and the grid operator, if the hydro-FPV system can share some of the existing electrical infrastructure (e.g., transformers, circuit breakers or transmission lines) [11]. The performance of PV modules is highly affected by solar irradiance and ambient temperature. For example, an efficiency decrease by about 0.45% for every degree rise in temperature for monocrystalline (c-Si) and polycrystalline (pc-Si) silicon solar cells has been reported [12]. Several studies have reported superior performance of FPV systems compared to ground-based solar PV [13]. This is often attributed to the enhanced cooling effect due to deployment on water bodies, resulting in a higher heat loss coefficient [14]. For example, the operating temperature was reported to be about 3.5 °C lower for FPVs compared to conventional ground-mounted PV panels in a case study located in China [15]. This was found to result in about a 1.6–2.0% increase in energy yield. Other studies have also reported cooling effect induced improved module efficiency [16–18]. However, the performance of FPV system can be highly dependent on the used technology (e.g., installation design, floater structure and cell technology) and on the local climate [19]. In this regard, a study evaluating field data from sites in the Netherlands and Singapore reported that a gain in energy yield from the cooling effect comprised up to 3% in the Netherlands and up to 6% in Singapore [20]. However, recent papers have also reported only a modest cooling effect on typical pontoon-based floaters [4].

In addition to increasing the energy yield of the FPV unit, hybridisation can also lead to increased hydropower generation due to reduced evaporation from a reservoir, and hence overall output from the hybrid-FPV system. A case study of a hydropower system located in the São Francisco River basin showed that the PV source has a seasonal profile that can complement the natural inflow of the river [18]. As a result, the average energy gain generated by the hybrid hydro-FPV plant was 76%, with an increase in capacity factor of 17.3% on average. Additionally, hydropower can compensate for the variability in solar resource availability and demand, which can lead to greater energy quality and grid stability on a sub-hourly level [21]. Several papers have also highlighted the effect of reducing water evaporation in hydro reservoirs by covering reservoir surfaces with FPV modules. It is estimated that about 15 000–25 000 m^3 of water is saved for each MWp installed, using the Penman-Monteith method for some test cases in South Australia [22]. Similarly, water savings of about 743 million m^3/a with a 1% FPV coverage is estimated for existing hydropower reservoirs in Africa [23]. Studies have also highlighted the impact of the water body surface coverage ratio on the water quality due to algal concentration, and the overall hydropower generation due to restrictions on the minimum water level [24]. Moreover, a study of evaporation rates for different FPV topologies on water basins highlighted that also the characteristics of the floating systems impact the amount of evaporated water [25]. Even though considerable literature exists on evaporation rates, the results differ largely between the used methods, the geographical location of the site, characteristics of the floater structure, and water body surface coverage ratio.

Other papers have focused on the optimal dimensioning and generation scheduling of hybrid systems utilising different optimisation methods. For example, a long-term stochastic optimisation method was developed in a study of the complementary operation of hybrid hydro-PV systems considering streamflow and PV output uncertainty [26]. The authors showed that the long-term complementary operation of a hydro-PV hybrid system is more efficient than operating the hydropower and solar PV plants individually. Moreover, a non-linear multi-objective optimisation model for the long-term complementary operation of hydropower and solar PV has been presented in [27]. The authors showed that hydropower is one of the ideal compensation resources for solar PV since it can control the generated power with the reservoir, especially when solar radiation lacks due to the rainy season. Research on optimal dimensioning methods for utility-scale hybrid systems in different market conditions is more scarce. Several different optimisation methods have been used in hybrid system dimensioning problems. For example, a genetic algorithm-based optimisation method is used in the assessment of different off-grid FPV hybrid energy systems [28]. Another study proposed a particle swarm optimisation model for dimensioning a hybrid PV-wind-battery system by minimising the total annual costs [29]. A multi-objective optimisation model was used for the optimal dimensioning of a grid-connected hybrid system integrating hydropower, solar, and wind [30]. In this study, the authors highlight that cascade reservoir storage performance and solar/wind resource characteristics had a significant impact on energy complementation. Similarly, another study showed that hydropower installed capacity and annual solar curtailment rate can play crucial roles in the size optimisation of a PV system [31].

1.3. Aim, scope, and research questions

Despite growing research in optimal dimensioning of FPV technology, there are still uncertainties related to the techno-economic feasibility of grid-connected utility-scale hybrid-FPV systems under different market conditions, especially in emerging and developing economies. Moreover, research gaps remain in quantifying the impacts that the aforementioned co-benefits (e.g., improved system operation, reduced evaporation, increased PV module efficiency) have on the techno-economic feasibility of hybrid-FPV systems. These uncertainties may potentially hinder investments in emerging FPV technology, especially in developing markets where renewable energy has the potential to provide the cost-effective power needed to drive the area's economic growth and mitigate climate change impacts that could reduce the availability of existing hydropower.

This paper focuses on the optimal dimensioning and scheduling of grid-connected utility-scale hybrid hydro-FPV systems. The FPV and hydropower systems are coupled at a common substation, thus allowing for their operations to be co-optimised. This dimensioning-scheduling problem is formulated as a linear programming (LP) model. As suggested in [46] for the representation of hydropower in capacity expansion models, the Taylor expansion method is used where the head-dependent power equation is linearised and a convex discharge-dependent turbine efficiency is assumed. The authors report that the Taylor expansion method can greatly reduce the computation time while maintaining a high level of accuracy. The case study is based on a hypothetical cascade hydropower plant located in Sub-Saharan Africa. The techno-economic feasibility of the hybrid system is analysed under different types of revenue streams (e.g., power purchase agreement (PPA) based tariff, spot market) and load commitments. Moreover, resource complementarity between solar irradiation and reservoir water inflow during different weather years is analysed. This paper aims to address the following research questions:

- Is hybridisation of incumbent hydropower plant economically feasible in Sub-Saharan African power market conditions and how does the economics of a hydro-FPV system compare to a hydro-ground-mounted PV system?
- How should a power producer dimension a hybrid system to optimise its profits under different load commitment types and revenue streams (long-term PPA vs. spot market)?
- How does the year-to-year variability in precipitation (drought vs. heavy rainfall) affect the optimal dimensioning of the hybrid system, and consequently the optimal bid for long-term round-the-clock PPA?

2. Methodology

2.1. Description of the case study hybrid hydro-FPV system

The case study analysed in this paper is based on a cascade hydropower system located in Sub-Saharan Africa. The considered hybrid hydro-FPV system topology is illustrated in Fig. 1. The hybrid system comprises of cascade hydropower system where the upstream reservoir A is connected to the downstream reservoir B and the FPV systems can be installed on each reservoir water body. Key topology data regarding the hydropower system is presented in Table 1. The capital and fixed operating expenditures related to the incumbent cascade hydropower system are considered sunk costs. The techno-economic assumptions regarding both the FPV and ground-mounted PV (GPV) systems are based on the estimates from NREL's cost benchmarking for PV systems [32,47] and are presented in Table 2. Moreover, the hybrid system is assumed to be connected to the national grid with a grid-connection capacity of 126 MW, representing the maximum power output of the incumbent hydropower plant. Exchange rates for monetary values are retrieved from European Central Bank statistics [33] and are used to convert costs to the base year of 2020 (USD2020).

The hourly FPV system performance is simulated with the Photovoltaic Geographical Information System (PVGIS) tool (version 5.2) [34] using the following assumptions: PVGIS-SARAH2 solar radiation database, 13° tilt-angle (optimal tilt), 0° surface azimuth, fixed tilt mounting system, Cryst-Si PV module technology with 13% fixed loss and nominal power of 1 kWp. The fixed system loss parameter is assumed to consider losses due to soiling, inverter efficiency, cable losses and other balance-of-system losses as well as module degradation. The same assumptions are used for the GPV system with single-axis tracking performance simulation.

Linear interpolation is used to estimate the missing hourly values in the post-processing of energy yield data. Moreover, the energy yield E_h data is further converted to PV availability (i.e., capacity factors Cf_h) in (1) by considering the energy yield over the nominal power P.

$$Cf_h = \frac{E_h}{P}. \tag{1}$$

The natural cooling effect provided by the water body on the FPV module temperature is not directly considered in the simulated PV energy yield. However, previous studies have shown that the lower module temperature can affect the economics of the FPV system [11,35]. The sensitivity of the results on the assumption regarding efficiency improvement for the FPV modules is discussed in Section 4.

2.2. Description of modelled scenarios

The techno-economic feasibility of the hybrid system and the sensitivities affecting the dimensioning problem are analysed in scenarios representing: (i) different types of revenue streams and load commitments; (ii) resource availability during different weather years. In this study, two often used revenue streams in renewable energy projects are considered that are based on fixed and time-varying energy pricing. Due to data availability, the input data regarding power market conditions are based on historical Southern African Power Pool (SAPP) spot price[1] market data from 2014 to 2021 [36]. The following two different revenue streams and/or load commitment scenarios are analysed:

- Three-tariff PPA scheme: the producer is assumed to operate under a long-term round-the-clock PPA contract where the revenues are based on fixed tariffs and load commitments. In this regard, a hypothetical three-tariff scheme is assumed: firm peak price of 106 USD/MWh between 07:00–22:00, firm off-peak price of 54 USD/MWh between 22:00–07:00, and intermittent price of 30 USD/MWh. Tariff price levels are estimated based on the average spot prices during the peak and off-peak hours using historical spot price data from 2014 to 2021. Moreover, the firm load commitment levels are optimised for the off-peak and peak hours assuming 100% availability during the modelled year. Electricity generation exceeding the firm load commitment levels (i.e., peak, off-peak) is sold to the grid using the intermittent tariff.
- Spot market scheme: the producer is assumed to operate in a wholesale spot market where the revenues are based on time-varying day-ahead spot prices. In this regard, the spot price is based on the historical spot price data representing the average price level during the period 2014–2021 (66 USD/MWh in 2018–2019) [36]. The sensitivity of the results on the assumption regarding spot market price is discussed in Section 3 using high (94 USD/MWh in 2020–2021) and low (49 USD/MWh in 2017–2018) price scenarios. The modelled spot market scheme is based on economic dispatch without load commitment where the producer is assumed to be a price-taker (i.e., market participation by the producer is not assumed to influence the spot market price on its own).

The analysis of resource availability (and complementarity between solar irradiation and reservoir water inflow) is performed for three different weather year scenarios based on historical water inflow data (see Appendix A Fig. A.1). The scheduling period is assumed to start from November when the reservoirs are typically at their maximum level. Moreover, the three scheduling periods are modelled individually to highlight the effect of varying weather years on the hybrid system dimensioning, scheduling, and the consequent annual producer profits:

- The scheduling period between 1.11.2008 and 31.10.2009 represents the median year for inflows to the reservoirs.
- The scheduling period between 1.11.2015 and 31.10.2016 represents the dry year for inflows to the reservoirs.

[1] Spot price time series used in the analysis represents the unconstrained price, i.e., all regions time series.

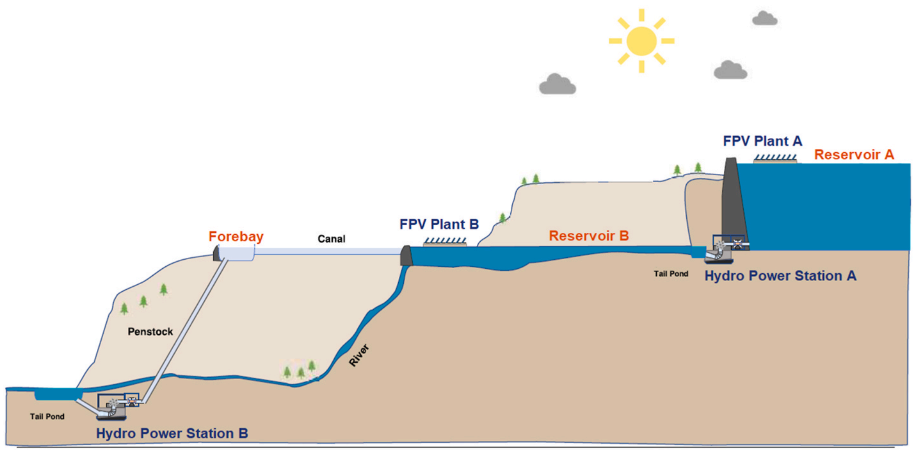

Fig. 1. Hybrid hydro-FPV system topology (modified from an image by Norconsult).

Table 1
Hydropower parameters.

	HRWL (m)	LRWL (m)	TWL (m)	Head loss (m)	d_{max} (m^3/s)	d_{min} (m^3/s)	V_{max} (Mm^3)	V_{min} (Mm^3)	P_{max} (MW)
Hydro plant A	490	479	464	0.65	160	–	1375	206.4	36
Hydro plant B	464	462	413	1.65	200	30	17.8	5.5	90

HRWL = high reservoir water level, LRWL = low reservoir water level, TWL = tail water level, d_{max} (d_{min}) = maximum (minimum) discharge, V_{max} (V_{min}) = maximum (minimum) reservoir volume, P_{max} = maximum turbine capacity.

Table 2
Solar PV system parameters.

	CAPEX[a]	OPEX[a]	Efficiency[a]	Tilt	Azimuth	System loss
	(USD/kWp)	(USD/(kWp a))	(%)	(°)	(°)	(%)
GPV	1130[b]	16.06[c]	19.9	–	0	13
FPV	1260[b]	15.5	19.9	13	0	13

[a] Data source: [32,47].
[b] The CAPEX of the inverter (40 USD/kWp) is included, which is used to dimension the inverter separately.
[c] Land lease cost is included, however, it can be highly site dependent.

- The scheduling period between 1.11.2007 and 31.10.2008 represents the wet year for inflows to the reservoirs.

Monthly solar PV energy yield and water inflow in the three weather years are presented in Fig. 2 and Fig. 3, respectively. Complementarity between solar irradiation and reservoir water inflow can be identified by comparing resource availability in dry (November to June) and rainy (July to October) seasons. Moreover, water inflow can vary significantly between median, dry and wet weather years (around -49–23% year-to-year variation), whereas the solar PV energy yield remains almost constant at the annual level (around 1% year-to-year variation).

2.3. Hybrid power system model

2.3.1. Linear programming model formulation

The hybrid power system model is formulated as a multi-horizon linear programming (LP) problem implemented in the JuMP framework, a domain-specific modelling language for mathematical optimisation embedded in Julia [37]. The abstract LP model can be formulated as follows,

$$\min_{x,y} z = \sum_{i \in I} \delta_i \left(c_i x_i + \vartheta \sum_{h \in H} q_i y_{ih} \right) \tag{2}$$

s.t.

$$a_i x_i \leq b_i, \tag{3}$$

$$y_{ih} - t_{ih} x_i \leq h_{ih}, \tag{4}$$

$$x_i, y_{ih} \geq 0. \tag{5}$$

The objective function (2) minimises the sum of the investment c_i and operating costs q_i of the hybrid power system (in each investment period $i \in I$ and operational period $h \in H$). In this regard, the variables x_i and y_{ih} represent the investment and operational decision variables, respectively. The term $\delta_i = (1+r)^{-n(i-1)}$, discounts all future costs at an annual discount rate r (5%) during n years in between each investment period. Hence, the system costs are converted to represent the equivalent monetary value in the first investment period. The term $\vartheta = \sum_{j=0}^{n} (1+r)^{-j}$, discounts annual operational costs n years ahead (until the next investment period). Constraint (3) ensures that investments in the power system assets are bounded so that the lifetime of the asset is considered across the investment periods. Moreover, constraint (4) ensures that the operation of the power system assets is bounded by the investment decisions and assets availability (t_{ih} e.g., solar PV capacity factor), and that supply balances demand h_{ih}. Constraint (5) ensures that the investments and the operation of assets are non-negative.

The LP model formulation supports investment decisions in generation, storage, and grid capacity. In this regard, the investment cost c_i for power system asset in period i is estimated in equation (6),

$$c_i = \frac{1 - (1+r)^{-\min(n|P| - p + 1, L)}}{1 - \frac{1}{1+r}} AC_i \tag{6}$$

$$AC_i = \frac{WACC}{1 + WACC - (1 + WACC)^{1-L}} CAPEX_i + OPEX_i \tag{7}$$

In (6), the annual capital $CAPEX_i$ and fixed operational $OPEX_i$ expenditures are discounted only considering the expenditures for the asset's lifetime L during the model horizon $|P|$. In (7), the weighted average cost of capital ($WACC$) is assumed to be 5%.

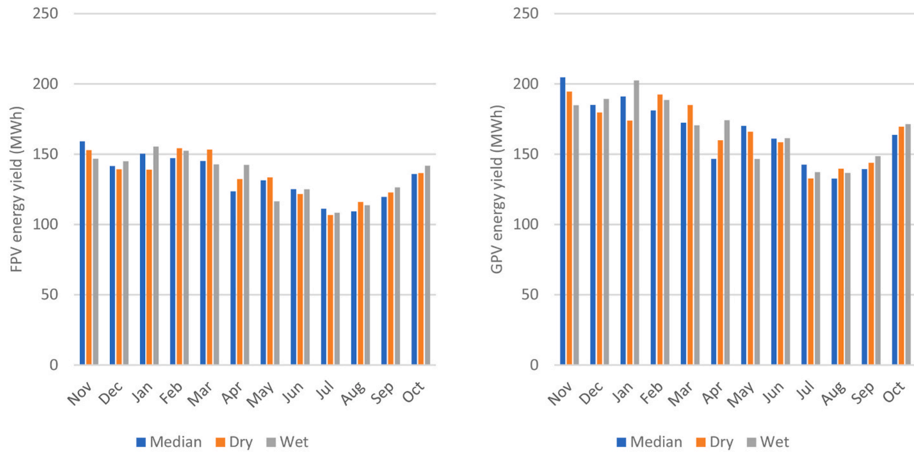

Fig. 2. FPV (left) and GPV (right) systems monthly energy yield (nominal power of 1 kWp).

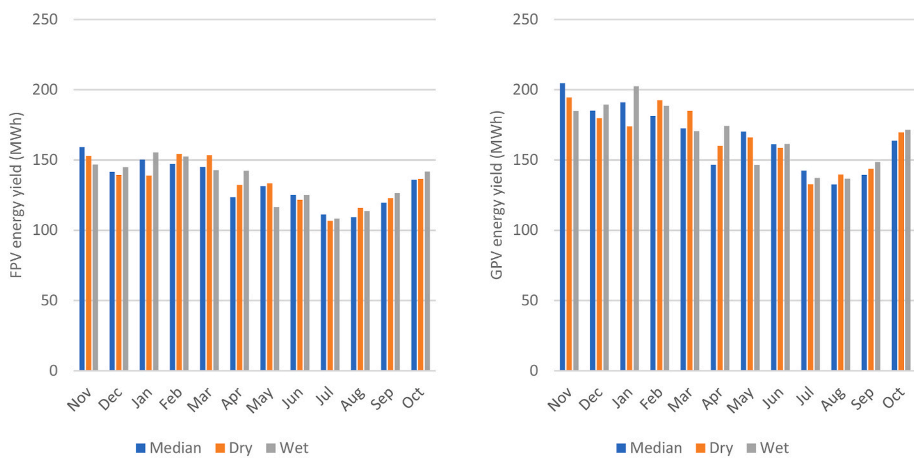

Fig. 3. Water inflow to reservoir A (left) and local water inflow to reservoir B (right) in the median (2008–2009), dry (2015–2016), and wet years (2007–2008).

2.3.2. Hydropower formulation

Hydropower generation (8) in plant k by turbine j is linearised using Taylor expansion around the mean head $\overline{H}_n$ and the mean effective discharge $\overline{E}_{nj}$ (9), as presented in [46]. Piece-wise linear dependency is assumed between reservoir volume and head water level (10), and between efficient discharge e_{hkj} and discharge d_{hkj} (11),

$$y_{hk} = \sum_j \left(e_{hkj}\overline{H}_k + \overline{E}_{kj}(h_{hk} - htail_k - hloss_k) - \overline{E}_{kj}\overline{H}_k \right)\rho g \tag{8}$$

$$\overline{E}_{kj} = \overline{D}_{kj}\overline{\eta}_{kj}, \tag{9}$$

$$h_{hk} \leq m v_{hk} + b, \tag{10}$$

$$e_{hkj} \leq m d_{hkj} + b. \tag{11}$$

In (10), the coefficients m and b represent the piece-wise linear dependency between reservoir volume and head water level, as illustrated in Fig. 4. In (8), the hydropower turbine efficiency[2] is included via linear and convex formulation of the effective discharge. To make the feasible region convex, the first segment is chosen as a polynomial tangent that passes through origo. Thus, the turbine efficiency is assumed to be discharge-dependent for high discharge rates and constant for low discharge rates, as illustrated in Fig. 5. In (11), the coefficients m and b represent the piece-wise linear dependency between effective discharge and discharge, as illustrated in Fig. 5.

The water balance equation (12) is formulated to capture the changes in reservoir volume and water flow between the hydropower plants. Moreover, equations (13) and (14) represent the lower and upper boundaries for the reservoir and head water levels, respectively, dictated by the reservoir dimensions.

$$v_{hk} = v_{h-1,k} + I_{hk} - \Delta v_{hk} - \sum_j d_{hkj} + s_{hk} + \sum_{k'} \left(\sum_j d_{h-\tau,kj} + s_{h-\tau,k} \right), \tag{12}$$

$$vmin_k \leq v_{hk} \leq vmax_k, \tag{13}$$

$$hmin_k \leq h_{hk} \leq hmax_k, \tag{14}$$

$$\sum_j d_{hkj} + s_{hk} \geq dmin_{hk}, \tag{15}$$

$$d_{hkj} \leq dmax_{hkj}. \tag{16}$$

Reservoir level recycling is assumed, i.e., the reservoir levels at the end of the scheduling period are assumed to be higher or equal to the reservoir levels at the start of the scheduling period. Traversal time (τ) from reservoir A to reservoir B is assumed to be 1 h. Minimum water discharge through the hydropower plant k (15) is assumed to be dictated by the environmental minimum flow. Maximum water discharge (16) through the turbine is dependent on the turbine inlet dimensions.

In (12), Δv_{hk} represents the volume of the evaporated water from the reservoir k. In this regard, the volume of evaporated water is

[2] Including generator efficiency.

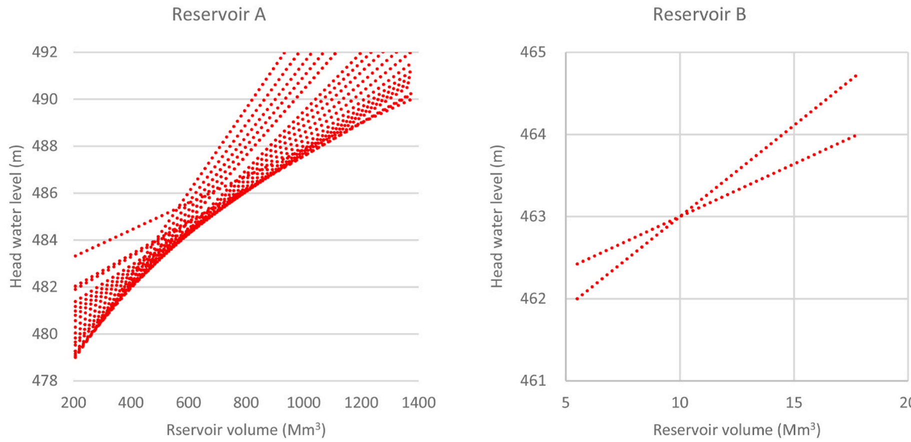

Fig. 4. Head water level as a function of reservoir volume in hydropower plant A (left) and plant B (right).

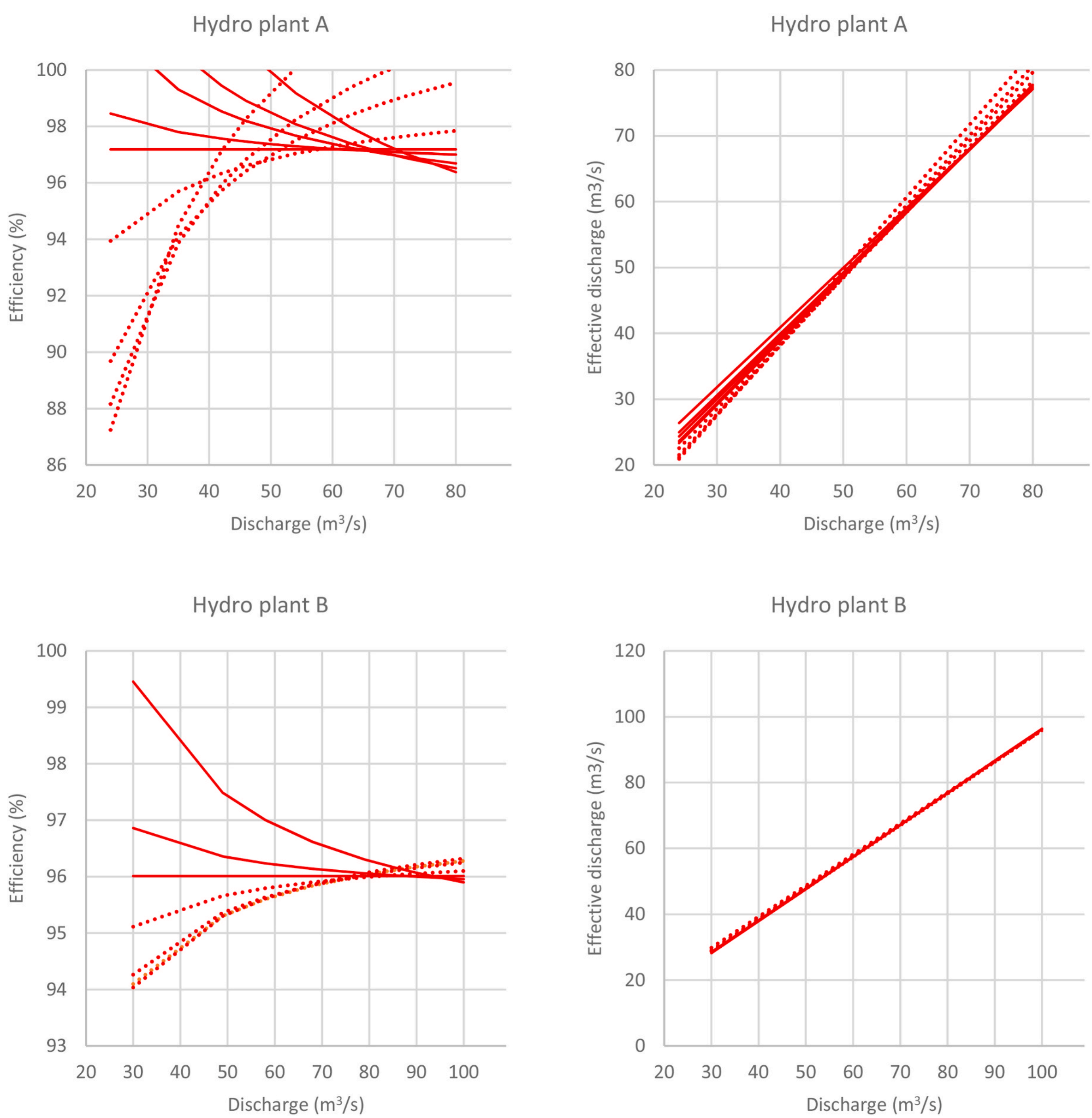

Fig. 5. Discharge-dependent turbine efficiency (left) and consequent effective discharge (right). The effective discharge curves represent the solid lines from the discharge-dependent turbine efficiency figure.

approximated in (17) based on the evaporation rate and the difference between the available water body surface area in the reservoir (A_k) and the water body surface area covered by FPV modules ($A_k^{'}$). Moreover, coefficient ε (60%[3]) considers the evaporation reduction caused by the reduced portion of solar radiation passing through the FPV modules that reach the water body surface [25]. The sensitivity of the results on the assumption regarding evaporation rate reduction is discussed in Section 4. Due to data availability, one year of the monthly evaporation rate data is assumed to represent evaporation rates in all considered weather year scenarios (see Appendix A Fig. A.2). The available water body surface area in reservoir k is assumed to be linearly dependent on the reservoir volume (18).

$$\Delta v_{hk} = evap_{hk}(A_k - \varepsilon A_k^{'}), \tag{17}$$

$$A_k = mv_{hk} + b, \tag{18}$$

$$A_k^{'} = \frac{\sum_i x_{ik}(\cos\theta + 1.2\sin\theta)}{\eta 1000W/m^2}. \tag{19}$$

The water body surface area covered by the FPV modules is estimated in (19) where x_{ik} represents installed FPV capacity in reservoir k, θ represents the tilt-angle of the FPV modules, and η represents the PV module efficiency (19.9%). Mutual shading losses can also be significant for utility-scale PV systems if the inter-row distance (pitch) is not correctly dimensioned [18]. Increasing the pitch results in a higher area occupancy factor for the PV module, i.e., a larger installation area is required for the same PV peak power. In this study, the inter-row distance is assumed to be 20% longer than the height of the PV modules from the ground, as suggested in [35].

3. Results

3.1. The effect of hybridisation on the hydropower plant economics

The hybridisation of the incumbent hydro-only system with FPV (or GPV) can increase the annual producer profits, as presented in Fig. 6. At the given conditions, the increase in the annual producer profits is observed to be higher in the PPA market scheme, being around 18–21% higher compared to the hydro-only system. The revenues in the PPA market scheme are mainly generated by maximising the firm peak power level.

In the spot market scheme, the increase in the annual producer profits is observed to be more dependent on the weather year. In the median (and wet) weather year, hydropower generation is highly available throughout the year. Moreover, since the grid connection is dimensioned based on the incumbent hydro-only system, the available grid capacity limits the potential for the FPV to participate in the spot market during the peak price hours. Consequently, only a negligible increase in the annual producer profits (<0.1%) can be achieved with hybridisation with FPV in the median weather year, whereas in the wet weather year hybridisation with FPV is not observed to be economically feasible. Vice versa, in the dry weather year, hybridisation with FPV can compensate for the decrease in the producer revenues caused by the reduction in the hydropower output, resulting in around a 4% increase in the annual producer profits. The results are observed to be sensitive to the spot price assumptions. For example, the limited potential for the FPV to participate in the spot market in median and wet weather year scenarios is observed to be offset by higher spot price assumptions. This renders the investment to FPV economically feasible, however still with lower invested capacity, as presented in Fig. 7. On the other, investment in FPV is observed to become economically infeasible in the dry weather year scenario with lower spot price assumption.

Moreover, the hydro-GPV system is observed to generate higher annual producer profits compared to the hydro-FPV system in all analysed scenarios (around 13–18%). This is mainly due to the lower CAPEX of GPV, as well as higher energy yield, being around 24% higher at the annual level due to the single-axis tracking. For the hybrid-FPV system to reach the same annual producer profits, the CAPEX of FPV should be around 52–57% (42% in the spot market scheme) lower than that of GPV at the given conditions.

3.2. The effect of the market scheme and weather year on the hydro-FPV dimensioning and operation

The optimal dimensioning of the FPV system under the different market schemes and weather year scenarios is presented in Fig. 7. As shown with the producer profits, the optimal dimensioning of the hydro-FPV system is highly dependent on the selected market scheme and the weather year. In this regard, the weather year mainly affects the available water inflow during the year (see Fig. 3), whereas the solar PV energy yield remains almost constant[4] between the considered weather years (see Fig. 2). As a result, the annual hydropower generation can vary by two-fold between the wet and dry weather years, as presented in Fig. 8.

In the spot market scheme, the available grid-connection capacity limits the potential for the FPV to participate in the spot market during the peak price hours. This can be observed especially in the median and wet weather year scenarios when the possibilities to increase the producer profits with hybridisation are limited or not feasible. As a result, the optimal dimensioning of the FPV system varies significantly depending on the weather year scenario (0–155 MWp).

In the PPA market scheme, over-dimensioning the hydro-FPV system (compared to the grid-connection capacity of 126 MW) is observed to maximise the producer profits. This allows higher firm peak power level and hence maximises the potential revenues during the firm peak hours. Moreover, the optimal inverter capacity is observed to slightly increase in relation to the optimal FPV module capacity as the water inflow availability decreases. This is because a lower DC/AC ratio will allow a higher firm peak power level that can be delivered with 100% availability. In the PPA market scheme, less variation is observed in the optimal dimensioning of the FPV system between the considered weather years (126–153 MWp). This can be attributed to a more constant revenue stream due to the load commitment and fixed tariff levels.

In mid- to long-term operation, hybridisation with FPV is observed to compensate for the variations in the hydropower generation between the dry and rainy seasons and in the different weather years, as presented in Figs. 8 and 9, respectively. The optimal short-term operation of the hydro-FPV system largely depends on the market scheme. In the PPA market scheme, the hydro-FPV system is operated to maximise the revenues at the firm peak and off-peak hours, as presented in Fig. 10. In this regard, the firm peak power level that can be delivered with 100% availability is observed to be highly depended on the weather year, being 71 MW and 106 MW in the dry and wet weather years, respectively. In comparison, the hydro-only system can deliver a firm peak power level of 41 MW and 61 MW in the dry and wet weather years, respectively. Moreover, in the short-term operation, hydropower is observed to compensate for the variability of FPV generation to achieve 100% availability. At the given conditions, the optimal firm off-peak power level is the same as the minimum discharge level (i.e., the environmental minimum flow) set for hydro plant B. In the spot market scheme, the hydropower plants are operated to maximise the revenues in the day-ahead spot market, as presented in Fig. 11. Hence, the

[3] The coefficient represents evaporation reduction for a floating PV structure where the floats cover entirely the water surface below the module.

[4] It should be noted that the wet weather year proved to have the highest annual PV energy yield, however the year-to-year variation was only around 1% between the considered weather years.

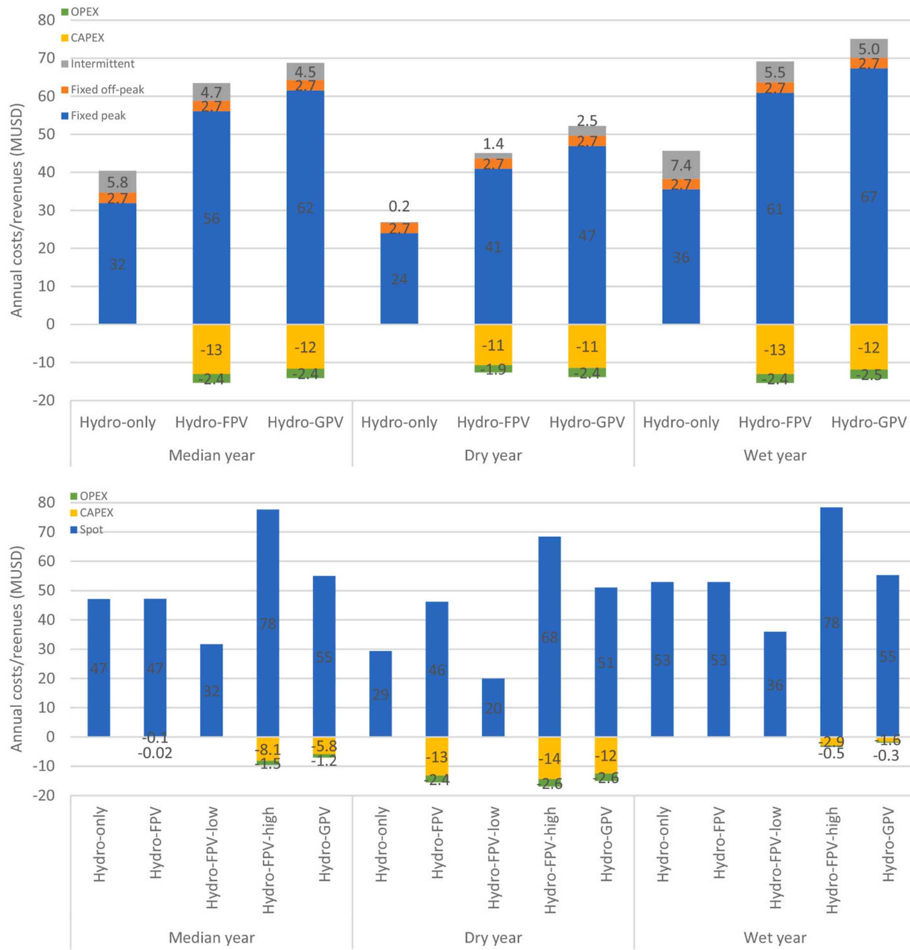

Fig. 6. Annual producer profits (sum of the costs and revenues) with varying system topology, market scheme and weather year scenarios. The annual costs/ revenues under the PPA market scheme are presented in the top figure and under the spot market scheme in the bottom figure.

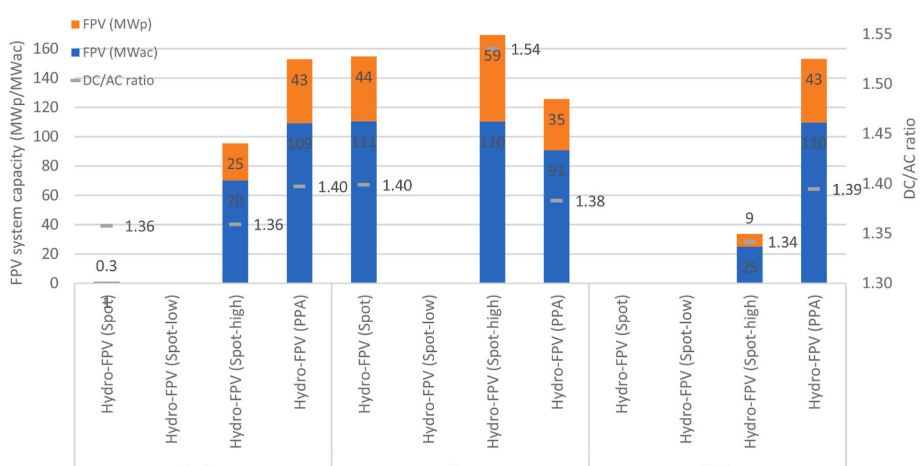

Fig. 7. FPV system capacity in the PPA market and spot market schemes and in the median, dry and wet weather year scenarios.

hydropower generation mainly follows the spot price curve, whereas FPV generation is dispatched regardless.

4. Discussion

The results presented in this paper are in line with the recent publications regarding hybrid hydro-FPV systems. In the case study, similar improved system operation at different time scales is observed due to the resource complementarity as reported in the previous studies [27,38]. This resource complementarity can mitigate the effects that climate change can have on the reducing inflow and hydropower generation in the long-term [39]. The effect of lower module temperature on the economics of the FPV system is analysed by considering that improved cooling results in a 7% increase in the annual FPV energy yield, as

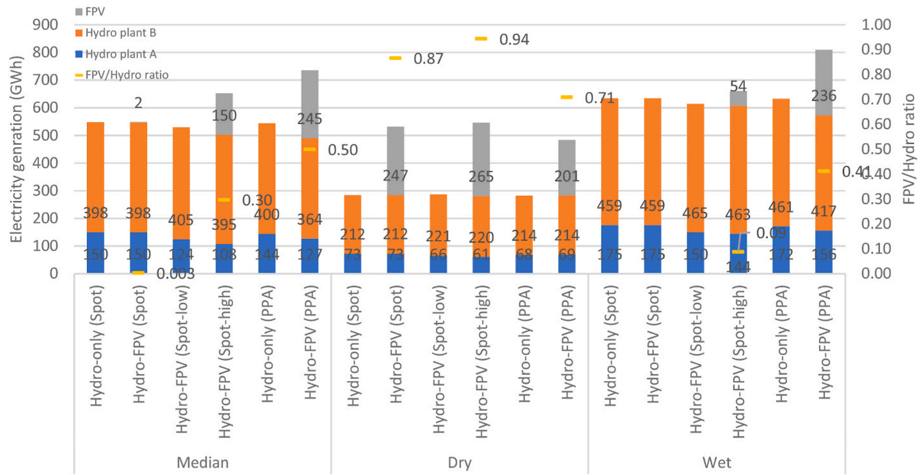

Fig. 8. Annual electricity generation for the different system topologies in the PPA and spot market schemes, and in the median, dry and wet weather year scenarios.

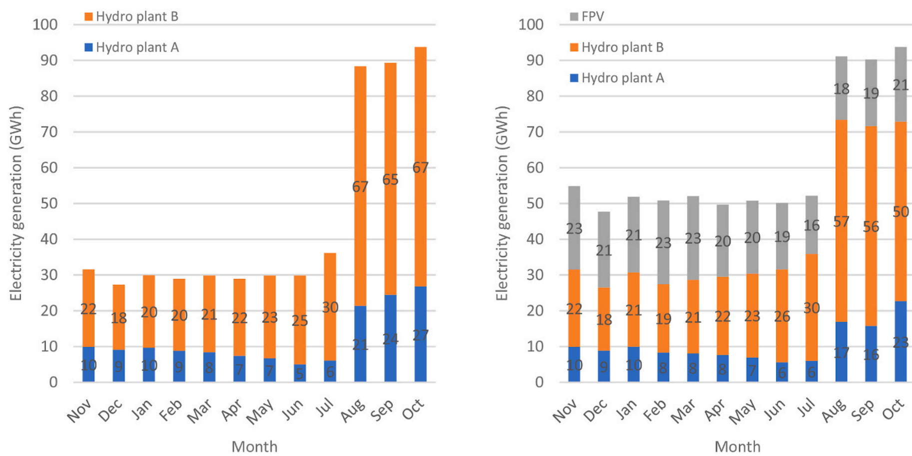

Fig. 9. Monthly electricity generation for the hydro-only (left) and hybrid-FPV (right) systems in the PPA market scheme in the median weather year scenario.

estimated in [18]. When the improved thermal performance is considered, the hydro-FPV annual profits increase by 2–3% (0–3% in the spot market scheme) compared to the hydro-FPV system without additional module cooling. However, the CAPEX of the FPV system must still be reduced by around 46–50% (36% in the spot market scheme) for the hybrid-FPV system to reach the same annual producer profits as the hydro-GPV system. Accurate estimation of the potentially improved thermal performance and other factors can be important since the factors that dominate the energy yield are also found to have the largest effect on the economic performance of FPV [40]. In this regard, the performance of the FPV system can be highly dependent on the used technology (e.g., installation design, floater structure and cell technology) and on the local climate [19].

One of the main co-benefits attributed to the FPV systems is the potential to reduce water evaporation from the reservoirs, which can be vital, especially in arid and semi-arid regions [41]. In the case study, partially covering the reservoir with FPV modules is observed to reduce water evaporation from the reservoir, thus affecting the hybrid system operation. However, the reduced evaporation from the reservoir is not observed to affect the optimal design of the FPV system. In the case study, for a cascade hydropower system, it is observed to be optimal to install the FPV system on the reservoir with the largest reservoir volume, in this case on reservoir A. This is because reservoir A can store excess energy from the reduced water evaporation for a longer period, and hence can provide better arbitrage opportunities for the excess energy. On the other hand, over-dimensioning the FPV system is observed to increase spilling from both reservoirs. This occurs especially during the rainy season in the median and wet weather years, as illustrated in Fig. 9. As a net effect, the annual hydropower generation is observed to decrease by around 10%. Vice versa, in the dry weather year when the water inflow availability is more limited, hydropower generation by hydro plant A is observed to increase slightly, which can be attributed to the reduced water evaporation from reservoir A. However, this effect is found to be negligible (around 1.2% at the annual level) due to the relatively small surface area covered by the FPV system (around 0.6–1.7%[5] of the available reservoir water body area is covered depending on the reservoir level). Achieved evaporation reduction with similar surface coverage ratios is in line with the estimates reported in previous studies [42]. However, it should be mentioned that an accurate evaluation of the reduced can only be achieved considering a range of variables, e.g., temperature, humidity, wind speed, and air pressure from the project location.

This study is limited in terms of the used hydropower modelling method. In this study, the Taylor expansion method is used for approximating the head-dependent power equation and discharge-dependent turbine-efficiency curves. The benefit of the used method is

[5] For example, the upper limit for the installed FPV capacity is estimated (using Eq. (19)) to be 8636 MW for the reservoir A and 640 MW for the reservoir B, respectively when the reservoirs are at the lowest water level (LWRL).

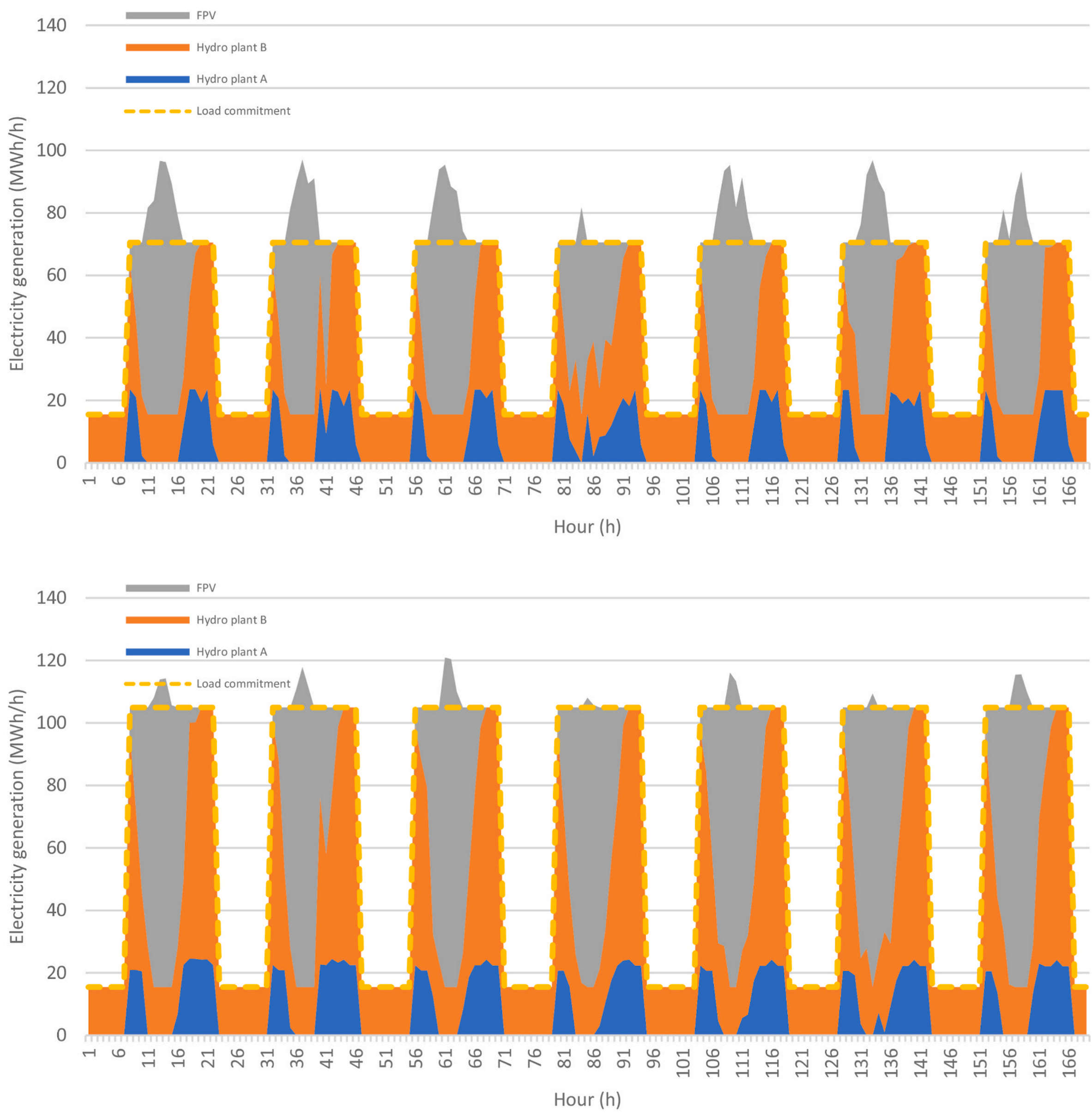

Fig. 10. Electricity generation in the PPA market scheme in the dry (top) and wet (bottom) weather year scenarios. The figure presents electricity generation during the first week of June (before the rainy season).

greatly reduced computation time while maintaining a high level of accuracy [46]. However, the used method can overestimate the flexibility and efficiency of the turbine at lower discharge levels, which has an effect on the system operation costs [43]. Moreover, head-sensitive hydropower approximation can affect investment decisions causing bias in the optimal generation mix [44]. Modelling accuracy of head-dependent production and discharge-dependent turbine efficiency can be improved with more sophisticated modelling methods, e.g., mixed-integer linear programming [45].

5. Conclusions

This study analyses the techno-economic feasibility of the hybridisation of an incumbent cascade hydropower system with FPV (and GPV) in Sub-Saharan African market conditions. This study aims to highlight how operation under round-the-clock tariff-based and varying energy pricing with and without load commitments affects the optimal dimensioning of the grid-connected utility-scale hybrid system. Moreover, the effect of resource complementarity of water inflow and solar irradiance on the co-optimised hybrid system operation is highlighted in varying weather year scenarios. The conclusions from the presented case study are as follows:

- In mid- to long-term operation, hybridisation with FPV can compensate for the intra-year variations in hydropower generation, e.g., between the dry and rainy seasons. Moreover, hybridisation can reduce the inter-year variability in electricity generation, e.g., between the dry and wet weather years. However, no anti-correlation between the yearly water inflow and solar irradiance is observed for the selected weather years. For example, the modelled wet year has the highest total yearly water inflow, as well as the highest total solar PV energy yield. In the short-term, hydropower can compensate for the intra-day variability of FPV generation.
- In the case study, the hybridisation of incumbent hydro-only systems can increase the annual producer profits in both a PPA and spot market scheme in Sub-Saharan African market conditions. The annual producer profits are observed to increase by 18–21% and 0–4% for the PPA and spot market structure respectively, compared

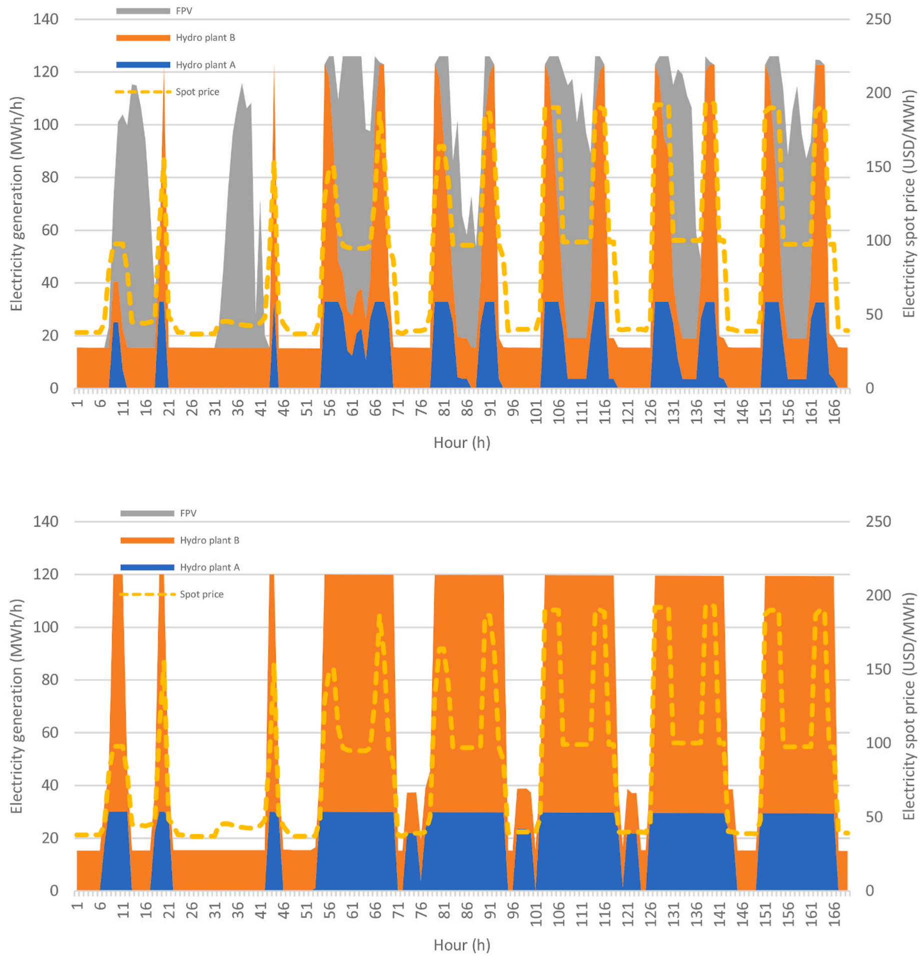

Fig. 11. Electricity generation in the spot market scheme in the dry (top) and wet (bottom) weather year scenarios. The figure presents electricity generation during the first week of June (before the rainy season).

to a hydro-only system. The PPA market scheme can reduce the financial risks related to the renewable energy project due to the more constant revenue streams. In this regard, less variability was observed in the optimal dimensioning of the hydro-FPV system in the PPA market scheme between the different weather year scenarios, compared to the spot market scheme.

- At the given case study conditions, hybridisation with GPV (with single-axis tracking) can be a techno-economically more feasible option compared to the FPV system. This is due to the combined effect of lower CAPEX of GPV, and higher energy yield. It is estimated that the CAPEX of FPV should be around 52–57% (42% in the spot market scheme) lower than that of GPV for the hybrid-FPV system to reach the same annual producer profit. Considering the improved thermal performance of FPV or increased land rent costs for GPV can positively affect cost competitiveness. For example, when improved FPV thermal performance due to cooling from the reservoirs is considered (i.e., by increasing the energy yield by 7%), the new optimal design will result in a producer profit increase of 0–3% depending on the market scheme and weather year scenarios.
- In the case study, partially covering the reservoir with FPV modules is observed to reduce water evaporation from the reservoir. However, this effect was found to be negligible (around 1.2% at the annual level) in the studied hybrid system due to the relatively small surface area covered by the FPV system. In this regard, reduced evaporation from the reservoir did not affect the optimal dimensioning of the FPV system.

The work presented in this paper shows a linear programming-based modelling method for analysing the techno-economic feasibility of hybrid systems in Sub-Saharan African market conditions, also by considering the potential co-benefits of reduced evaporation from the reservoirs. However, the proposed model could also be used in the techno-economic feasibility analysis of FPV for other locations and markets. The results highlight the effects of different market schemes and varying weather years on the hybrid system dimensioning and operation. However, in the long-term modelling, the robustness of the results could be improved by including stochastic optimisation methods in the techno-economic analysis of the hybrid-FPV systems.

CRediT authorship contribution statement

Ville Olkkonen: Conceptualization, Methodology, Investigation, Data curation, Writing – original draft, Writing – review & editing. **Kristina Haaskjold:** Conceptualization, Methodology, Writing – review & editing. **Øyvind Sommer Klyve:** Conceptualization, Methodology, Data curation, Writing – review & editing. **Roar Skartlien:** Methodology, Writing – review & editing.

Declaration of competing interest

The authors declare that they do not have any known competing financial interests or personal relationships that could have appeared to influence the work presented in this paper.

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Appendix A

Historical water inflow data from 1970 to 2017 is presented in Fig. A.1. Moreover, the average water inflow to reservoir A in median (2008–2009), dry (2015–2016), and wet (2007–2008) weather years is illustrated in Fig. A.1. Monthly evaporation rate data is presented in Fig. A.2. Due to data availability, monthly evaporation rate data is extrapolated for each considered weather year.

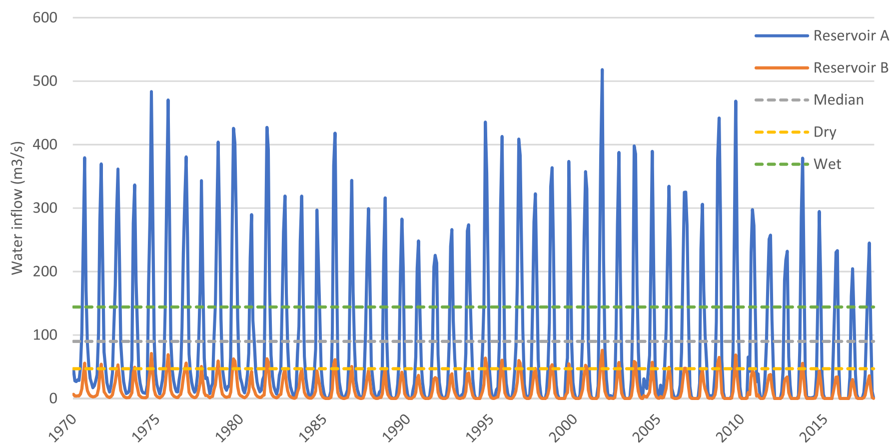

Fig. A1. Historical water inflow data from 1970 to 2017.

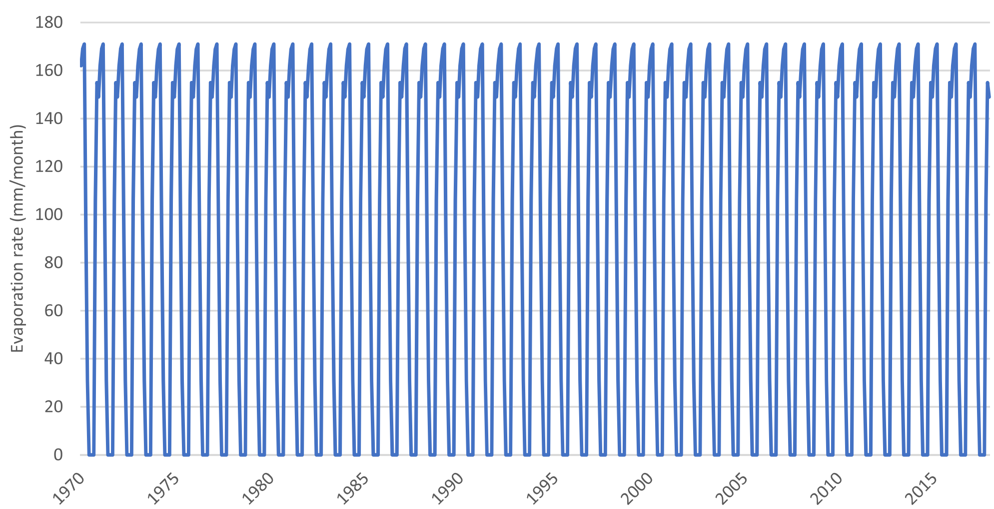

Fig. A2. Monthly evaporation rate from 1970 to 2017.

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