Impact of energy pricing regimes on production schedules under solar-hydro hybridization

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***Abstract*—Hybridization of complementary energy production increases system flexibility and allows optimization of energy and resource availability. Hydropower and floating solar photovoltaics (FPV) have a high potential for hybridization, but further market understanding is required to design advantageous power purchasing agreements (PPA) and accelerate market integration of renewable energy sources. In this paper, we focus on the impact of energy pricing regimes on determining the maximum firm load obligation, reservoir trajectory, and dispatch plans in the context of combining solar and hydro production. The modeling of FPV generation is included in an operational hydro-scheduling tool used by many hydropower producers in the Nordics. Numerical results show that solar-hydro hybridization offers more pronounced complementarity in the dry season when the reservoir can provide flexibility on dispatching than in the wet season when all the units run at maximum capacity day and night to avoid flooding. A 3-tariff price structure provides the highest net revenue in most load obligation settings, while day-ahead price leads to significant reservoir water level variations and hence may pose challenges for the mooring system of FPV installation. This study assesses the benefits and limits of various energy pricing regimes under solar-hydro hybridization, which is crucial for the plant owner to make a considerate PPA with the local government or offtaker.**

Keywords*—*Energy pricing regimes, Optimization, Power purchasing agreement, Solar-hydro hybridization

I. Introduction

As the energy transition progresses, there is an increasing need for research and development in energy solutions that can satisfy the energy trilemma of reliability, affordability, and sustainability. The IEA World Energy Outlook 2022 guidelines for a secure energy transition include scaling up a range of clean energy technologies and investing in system flexibility [1]. With the increasing share of low-cost variable renewable energy (VRE) in the electricity mix comes additional challenges of weather-dependent power reliability. One approach to mitigate these challenges is to develop hybridized power plants (HyPPs), pairing intermittent VREs with flexible generation.

This paper explores the potential benefits of solar-hydro hybridization for a cascaded watercourse composed of two hydropower plants with floating photovoltaics (FPV) on reservoirs. There are several motivations for research into hybridizing these technologies. Most significant is the capability to optimize energy availability of reservoir inflow against solar irradiance potential [2-4]. There is beneficial complementarity between the highly seasonal inflow and the daily fluctuation of solar energy availability [3]. In particular, Africa has great potential for successful hydro-FPV HyPPs. With FPV covering 1% of the dam surface, up to a 58% increase in energy output has been simulated [5]. Furthermore, additional benefits include reduced land use, alleviated reservoir evaporation, shared electrical infrastructure and grid connection costs, lower maintenance costs, and lessened solar PV curtailment [4, 6].

Specifically considering large-scale hydro-PV HyPPs, the largest operating plant globally is the Longyangxia plant in China, comprised of land-based solar PV [7]. Economic equilibrium modeling research for this plant reaffirms the hypothesis that hydro and PV generation are highly complementary and that scheduling flexibility and total generation are greatly improved in a HyPP [2]. However, hydropower and solar PV are both highly seasonal, causing significant differences in curtailment losses between summer and winter [3]. The most common approach for optimal performance involves stochastic dynamic programming of both solar irradiance and reservoir inflow [7]. Particularly in China, this approach has been demonstrated to both increase total energy generation and decrease on-time for hydropower units [8].

The recent rise of VREs means system operators are increasingly interested in holding power purchase agreements (PPAs) with energy producers to ensure a reliable power supply. To the authors' knowledge, there is a literature gap regarding how HyPP performance is impacted by different market conditions. However, a thorough understanding of asset operation and profitability is required for renewable HyPPs to integrate into modern electricity markets and contracts. This paper aims to fill this knowledge gap by analyzing how different energy pricing regimes impact hydro-FPV HyPP scheduling behavior. The main research question is to find the optimal load obligation at peak hours a hydro-FPV HyPP can cover under those pricing regimes. The differences in reservoir trajectory, production duration curves, and dispatch plans are also analyzed in detail.

The hybrid scheduling tool used in this paper is based on the Short-term Hydro Optimization Program (SHOP), developed by SINTEF Energy Research and employed by many Nordic hydropower producers for daily operation. SHOP considers complex watercourses, technical details of the production system, and various strategic, regulatory, and

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market constraints [9]. Solar scheduling is modeled as a free energy source since the operation cost of FPV is almost zero. The available amount is equal to the FPV generation capacity.

The study investigates a commissioned hydro-FPV HyPP project in Western Africa with a PPA to fulfill firm load obligation for a set contract price during peak hours. Several cases are tested with varying pricing regimes dictating the purchase price of any excess energy produced. The variation in cases explores the possibility of high off-peak prices incentivizing power generation shifting and the HyPP responding to the volatility of the spot market price. The numerical results demonstrate the HyPP load coverage capability under a standard PPA structure and thus can be used by planned assets for optimal PPA design. It is valuable information for feasibility and profitability analysis to enable the integration of renewable HyPPs into the energy system.

The primary contribution this study offers to the current literature is a specific analysis of operational adjustments across different energy pricing regimes. To date, little quantitative and comparative analysis has been published on this topic. Furthermore, the research presented in this paper reveals the value of excess energy generation for a HyPP under a firm load obligation in the relevant market conditions.

The remainder of the paper is organized as follows: Section II presents the hybrid scheduling problem. Three types of energy pricing regimes are introduced in Section III. In Section IV, comparisons are made to illustrate the impact of pricing regimes on results. We end with concluding remarks and discussing future work in Section V.

II. Hybrid Scheduling Problem

The power plant owner is working on a PPA with the local government. Power generation comes from the combination of hydro and FPV. There are fixed peak and off-peak hours, repeating every day. The peak hours are from 7:00 to 22:00. A firm load obligation should be fulfilled during the peak period (Fig. 1). The predefined contract price will pay the load obligation, named the load price. If it is possible to sell the extra power beyond the load obligation to the market or electricity generated during off-peak hours, the price used in those situations is called intermittent price. The purpose of the hybrid scheduling problem is to find the maximum firm load obligation between 7:00 and 22:00.

Fig. 1. Illustration of daily firm load obligation from 7:00 to 22:00

For a given load obligation, the hybrid scheduling will determine the optimal production schedules by utilizing the water and solar resources economically. After optimization, net revenue is calculated by (1).

$$\begin{aligned} & Net\ revenue = Load\ income + Market\ income \\ & \quad - Start\ cost - Load\ penalty\ cost - Min\ flow\ penalty\ cost \end{aligned} \tag{1}$$

where

- $Load\ income = \sum_t load\ obligation_t \times load\ price_t$
- $Market\ income = \sum_t sale\ amount_t \times sale\ price_t$
  If there is a load obligation, $sale\ amount_t = hydro\ production_t + FPV\ production_t - load\ obligation_t$. If there is no load obligation, the production of hydro and FPV will be sold to the market. Therefore, $sale\ price_t$ is equal to the intermittent price above the load obligation or during off-peak hours.
- $Start\ cost$ is the sum of the start cost of all the generators during the scheduling period.
- $Load\ penalty\ cost$ is the sum of the penalty cost for not fulfilling the load obligation.
- $Min\ flow\ penalty\ cost$ is the sum of the penalty cost for breaking the minimum flow constraints of the river.

III. Energy Pricing Regimes

We check three energy pricing regimes to study their impact on determining maximum firm load obligation and production schedules.

A. 1-tariff price

We assume that the constant load price at peak hours is 145 USD/MWh (Fig. 2). The production from hydro and FPV can solely be used to fulfill the load obligation, and extra energy cannot be sold to the market, either during the peak hours or off-peak hours. FPV production will be curtailed if the total production of hydro and solar is higher than the load obligation. 1-tariff price is repeated daily. The total production and average price are computed as follows:

$$Total\ production = \sum_t (hydro\ production_t + FPV\ production_t - curtailed_t) \tag{2}$$

$$Average\ price = Net\ revenue / Total\ production \tag{3}$$

Note that $Net\ revenue$ under 1-tariff price omits $Market\ income$ listed in (1).

Fig. 2. Illustration of 1-tariff price for one day

B. 3-tariff price

Besides the constant load price at peak hours of 145 USD/MWh, two intermittent prices are introduced in 3-tariff pricing regimes (Fig. 3). If the total generation of hydro and FPV is higher than the load obligation or during the off-peak hours, the excess part can be sold to the market according to the intermittent prices. Since the intermittent price during off-peak hours (70 USD/MWh) is higher than the intermittent price during peak hours (30 USD/MWh), more hydro production will be shifted to the off-peak hours. 3-tariff price is repeated daily.

FPV production will not be curtailed when finding the maximum firm load under this price setting. Therefore, total production under the 3-tariff price becomes

$$Total\ production = \sum_t (hydro\ production_t + FPV\ production_t) \tag{4}$$

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The calculation of $Net\,revenue$ and $Average\,price$ is the same as (1) and (3).

Fig. 3. Illustration of 3-tariff price for one day

C. Day-ahead price

Under the day-ahead pricing regime, the load price has the same value as the market price (Fig. 4). Like the 3-tariff price, FPV production will not be curtailed. The excess power or generation during the off-peak hours can be sold according to the market price. The day-ahead price is derived from a day-ahead electricity market after scaling modifications (Fig. 5). Each hourly rate is scaled up by the ratio of the original yearly average price and the 1-tariff average price (64.87/90.625). Then the yearly average prices for both 1-tariff and the modified day-ahead price are the same. The numerical results obtained under different pricing regimes (Section IV) are hence comparable.

Fig. 4. Illustration of day-ahead price for one day

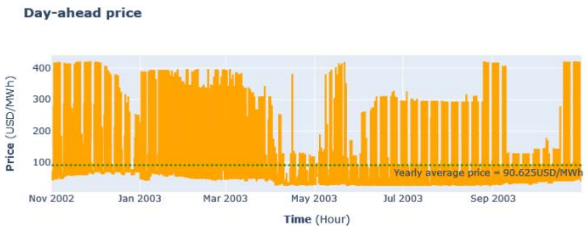

Fig. 5. Illustration of day-ahead price for one year

IV. Numerical Results

In this section, we first present the topology and input data of the watercourse in focus. Then we run the optimization model with the increase of load obligations to compare the results under the three pricing regimes discussed in Section III. Next, we choose one firm load obligation as a basis to further investigate the annual reservoir trajectory and load fulfillment. Finally, a zoom-in check will be done to study one-week production schedules under various pricing regimes in the wet and dry seasons, respectively.

All the tests are run by SHOP v14.5.0.6. All binary variables in the optimization model are relaxed. CPLEX 20.1.0 is the solver being used. The average calculation time for one case under 1-tariff, 3-tariff, and day-ahead price is 346 seconds, 355 seconds, and 259 seconds, respectively.

A. Basic information about the testing watercourse

The watercourse consists of two reservoirs and two HyPPs, each having two identical generating units (Fig. 6). The physical configurations of the watercourse are listed in TABLE I. There is a minimum flow requirement for the downstream river for environmental concerns. The penalty for breaking the minimum flow requirement is 1,000 USD/m^3/s.

The scheduling period is one year with hourly time resolution, from 2002.11.1 00:00 to 2003.11.1 00:00. The inflow to reservoirs is shown in Fig. 7. It is the closest year to the mean inflow for 48 years (1970 – 2017). After the wet season (1st June – 31st October), both reservoirs reach the maximum water level, which is the initial and end conditions in the optimization model.

No evaporation is considered in this paper. The FPV covers 1% of the reservoir's maximum surface area. Since FPV production is modeled as a free resource, the historical FPV production data are introduced to the model as capacity. The monthly average of non-zero FPV production is illustrated in Fig. 7, reflecting the seasonal complementarity of solar production and inflow availability.

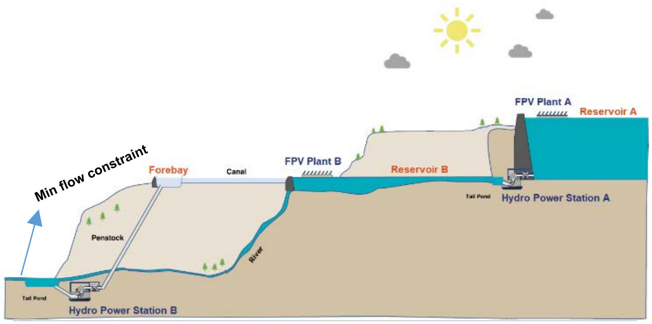

Fig. 6. Schematic topology of the testing watercourse

TABLE I. Key Topology Data

	Reservoir_A	Reservoir_B
Max water level (meter)	490	464
Min water level (meter)	479	462
Max volume (million m^3)	1,168.6	12.3
Max surface area (km^2)	162	7.7
	Plant_A	**Plant_B**
Outlet line (meter)	464	413
G1/G2 max production (MW)	18	45
G1/G2 min production (MW)	4.2	13.3
G1/G2 Start cost (USD)	10	10
	Downstream_river	
min flow (m^3/s)	30	
penalty cost (USD/m^3/s)	1,000	

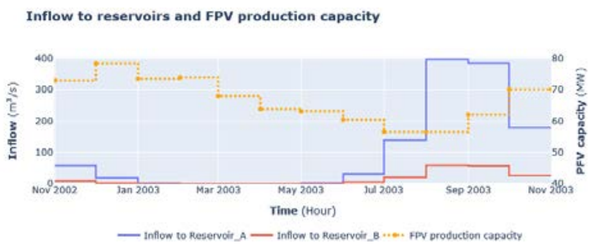

Fig. 7. Monthly inflow to reservoirs and average FPV production capacity

B. Determine maximum load obligation at peak hours

Net revenue, total production of hydro and solar, average price, and fulfilled load percentage are contrastively displayed in Fig. 8. At the beginning, the day-ahead price provides the highest net revenue. However, with the increase of load obligation from 90 MW to 126 MW (maximum hydro

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production in the system), less and less free solution space is left for the day-ahead pricing regime to optimally allocate the energy generation to the periods with higher prices. The net revenue keeps decreasing and is surpassed by the 3-tariff price when the load obligation is 96 MW before being caught up by the 1-tariff price after the load obligation becomes 114 MW.

The solar curtailment causes the production gap between 1-tariff and 3-tariff price/day-ahead price. With the growth of load obligation, less solar is curtailed, and more FPV production is exploited to fulfill the load.

Determining the maximum load obligation depends on the plant owner's agreement with the local government and the setting of load penalty costs. In all the tests, the penalty cost for failing to deliver load obligation is 5,000 USD/MWh, a default setting in SHOP and much higher than any observed market prices under all the pricing regimes. Though the load starts to be unfilled when the load obligation exceeds 110 MW, the fulfilled percentage is still more than 98% for all the pricing regimes when reaching the maximum hydro production limit (126 MW). If the minimum flow of the downstream river must be strictly complied with, then the maximum load obligation must be reduced to 120 MW since all three pricing regimes break the minimum flow constraint when the load rises to 121 MW (Fig. 9).

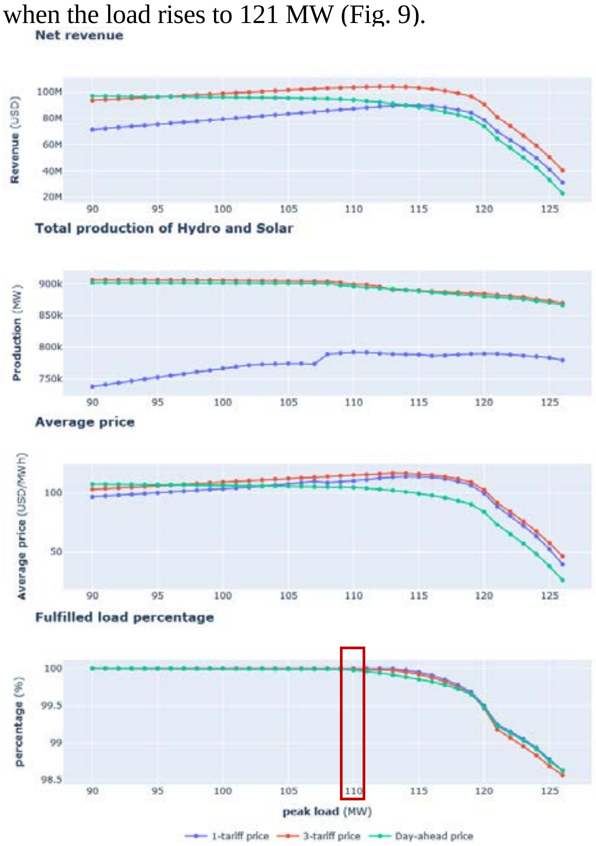

Fig. 8. Net revenue, total production, average price, and fulfilled load percentage with an increase of load obligation from 90 MW to 126 MW

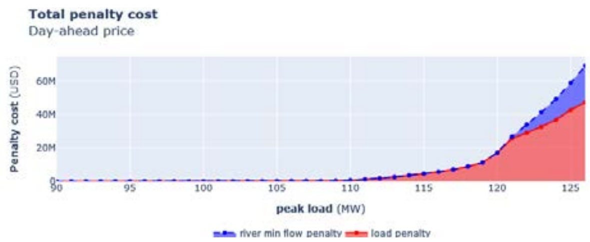

Fig. 9. Total penalty cost under day-ahead price with an increase of load obligation from 90 MW to 126 MW

C. Annual production patterns

We chose 110 MW as the given load obligation when further investigating the water level change of the two reservoirs and the difference in production duration curves under the three pricing regimes. We also run the optimization model against the day-ahead price without any load obligation. Thus, the production follows the trend of the spot price. The resulting figures of these four tests are displayed in Fig. 10.

In all four tests, the trajectory of the large Reservoir A is similar. It is almost emptied before the wet season arrives. By contrast, the small Reservoir B with big downstream generating units has distinct water level variance in different tests.

Under the 1-tariff price, the plant head is kept as high as possible to generate more power per cubic meter of water discharged. Even during off-peak hours when no power can be sold to the market, it keeps at least one unit in each plant running rather than only using the downstream unit to maintain the minimum flow constraint as the day-ahead price does.

Under day-ahead pricing, the fluctuation of water storage in Reservoir B is more pronounced. It approaches the bottom several times when there is no load obligation. This observation complies with real-world hydro scheduling in a day-ahead market. It is worth mentioning that significant water level variations would also mean that specific designs of FPV on reservoirs were necessary to keep tension in the cables and prevent the structure from drifting.

The energy generation only fulfills the load obligation under the 1-tariff price, resulting in no penalty. 3-tariff and day-ahead prices will suffer load deficits when water is scarce in the summer. As seen from the duration curves, neither hydro nor solar alone can fulfill the load obligation. Only a hydro-solar combination can achieve the goal.

As shown in TABLE II, the net revenue in the day-ahead price regime is about 5 million USD higher when there is no load obligation. In order to agree to deliver a fixed peak load of 110 MW throughout the year, the plant owner must be compensated at least 8.33 USD/MW for the firm capacity, as long as the load price is equal to the market price.

D. Compare production schedules in dry and wet seasons

Now we have a closer study of how the PPA affects scheduling and curtailment in two typical periods representing the dry season (2003.3.1 00:00 – 3.8 00:00) and wet season (2003.9.21 00:00 – 9.28 00:00). The figures in Fig. 11 indicate the comparison.

In the dry season, solar-hydro hybridization offers good complementarity. Peaks and troughs in the hydro generation are prominent. Hydro output is displaced from daytime to peak hours before sunrise or after sunset. Under day-ahead pricing, FPV and hydro production closely follow price changes. In the wet season, no matter what pricing regime, all the units run at maximum capacity day and night to avoid flooding. Solar is fully curtailed under the 1-tariff price.

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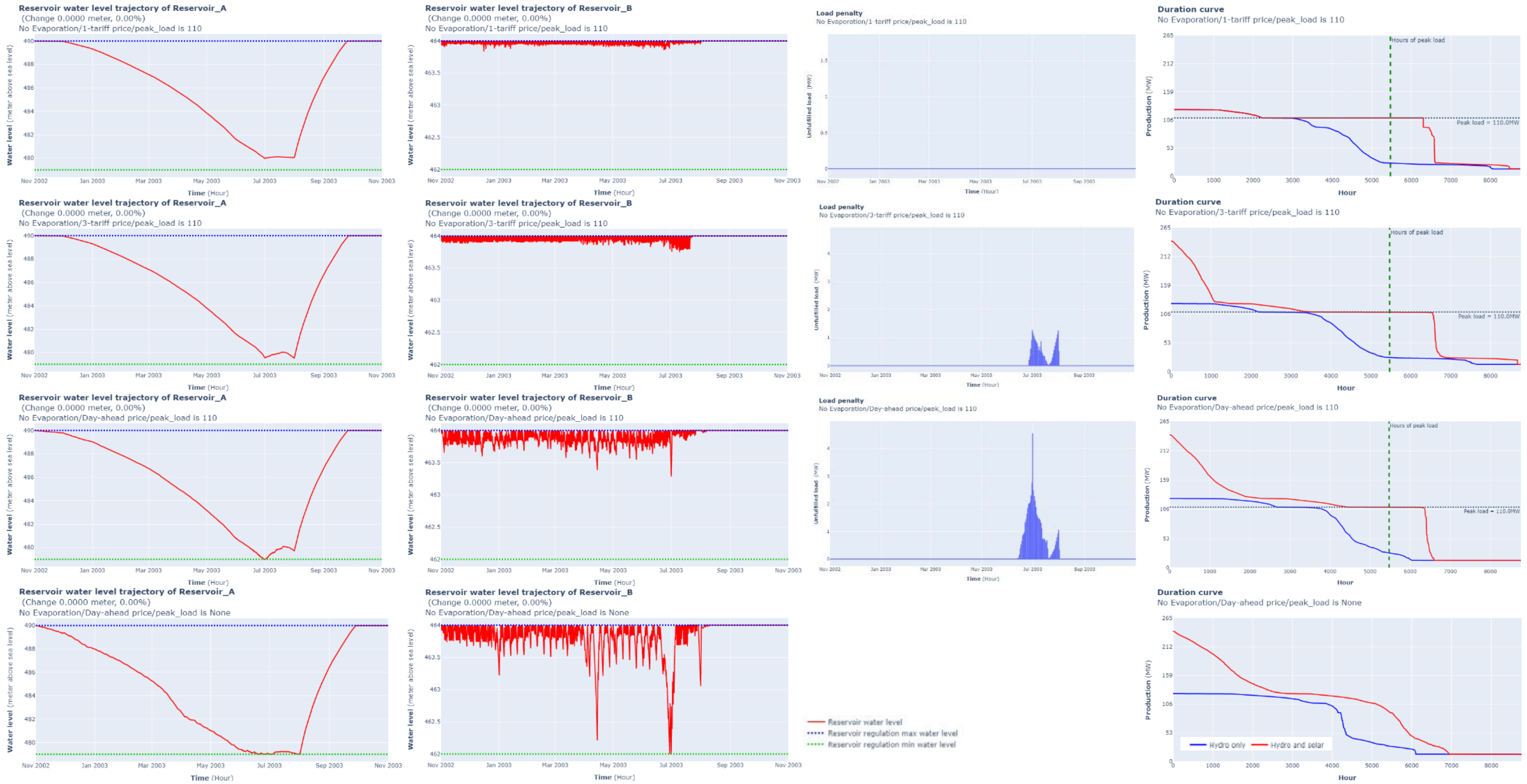

Fig. 10. Reservoir water level trajectories, load penalty, and production duration curves under three types of pricing regimes

TABLE II. ANNUAL RESULTS UNDER THREE TYPES OF PRICING REGIMES WHEN LOAD OBLIGATION = 110 MW

	Objective value (USD)					Net revenue (USD)	Production (MW)			Total production (MW)	Average price (USD/MW)	Fulfilled load obligation (%)
	Load income	*Market income*	*Start cost*	*Load penalty cost*	*Min flow penalty cost*		*Hydro*	*FPV*	*Solar curtailed (%)*			
1-tariff price	*87,326,250*		*13,540*	*0*	*0*	87,312,710	*598,975*	*193,203*	*35*	792,178	110.22	100
3-tariff price	*87,326,250*	*16,431,228*	*13,570*	*220,710*	*0*	103,523,198	*601,567*	*297,347*		898,914	115.16	99.99
Day-ahead price	*70,633,876*	*23,879,798*	*14,950*	*610,718*	*0*	93,888,006	*598,228*	*297,347*		895,575	104.84	99.98
Day-ahead price (No load obligation)		*98,916,369*	*9,980*		*0*	98,906,389	*602,831*	*297,347*		900,178	109.87	

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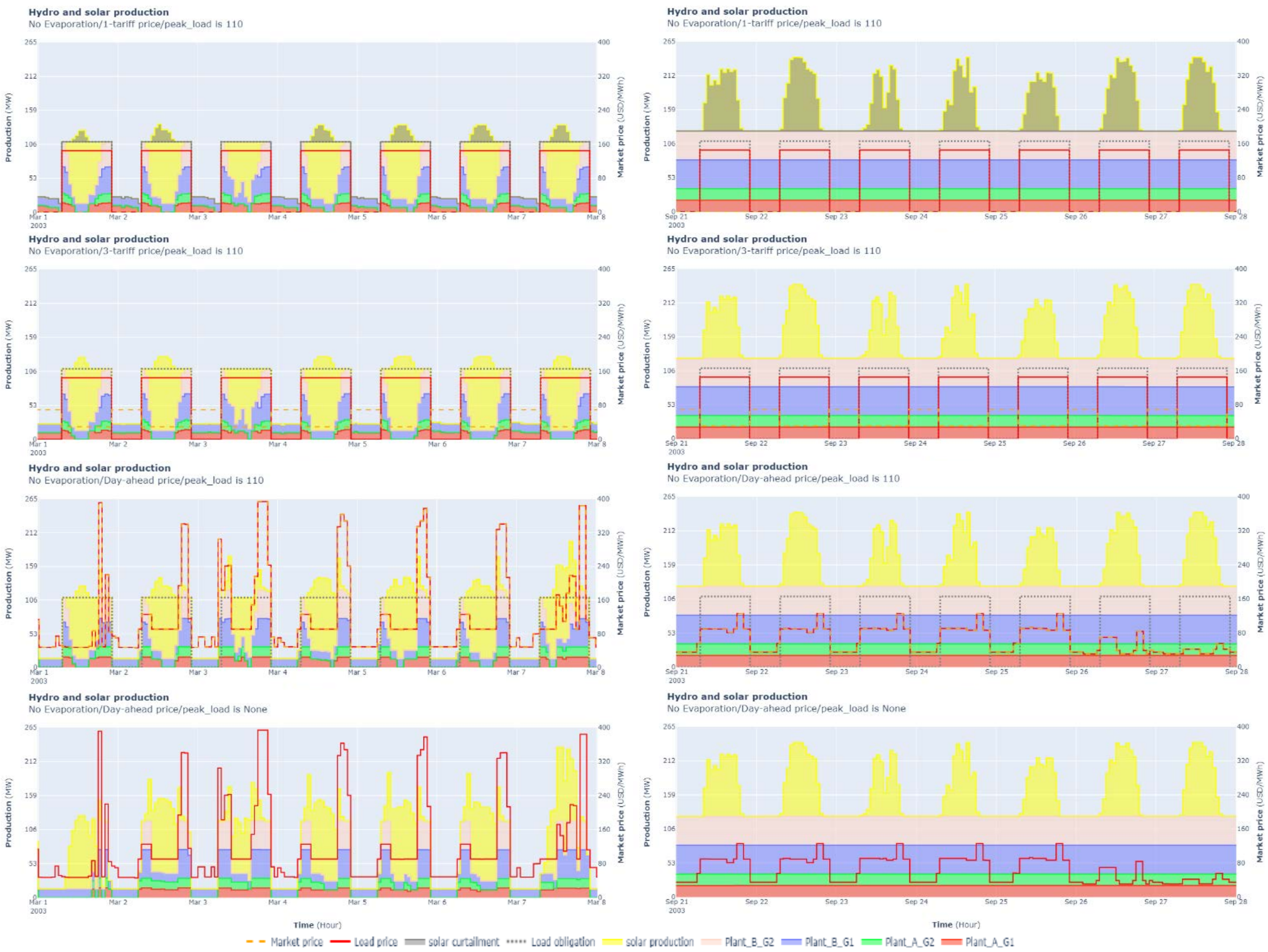

Fig. 11. Production schedules in dry season (2003.3.1 00:00 – 3.8 00:00) and wet season (2003.9.21 00:00 – 9.28 00:00) under three types of pricing regimes

V. Conclusion

In this paper, we first optimize the hybrid power production of solar and hydro to determine the maximum firm load obligation under three energy pricing regimes. Then the reservoir trajectories and production duration curves are studied for a given load obligation. Finally, we compare the production schedules during the dry and wet seasons. From an economic perspective, the 3-tariff price yields the highest net revenue in most load obligation settings since the income of hybrid scheduling can be guaranteed with a fixed load price and intermittent price. From a dam safety perspective, reservoirs are subject to greater water level variations in a day-ahead market, which poses challenges and risks for the mooring and anchoring system of FPV. The benefit of solar-hydro hybridization in the dry season is more evident than in the wet season.

Future research will include the evaporation losses and the negative correlation between inflow and solar during the years to make the conclusion more solid. The benefits of solar-hydro hybridization should be quantitively compared with the separative scheduling of hydro and solar.

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