ECONOMIC MODEL PREDICTIVE CONTROL FOR THE ENERGY MANAGEMENT PROBLEM OF A VIRTUAL POWER PLANT INCLUDING RESOURCES AT DIFFERENT VOLTAGE LEVELS

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ABSTRACT

In response to the requirement of a sustainable energy system, diversified energy resources and liberalization of electricity markets, the energy sector is experiencing worldwide a huge penetration of Distributed Energy Resources (DER). To maximize the benefits of these assets, DER can be aggregated in a Virtual Power Plant (VPP) and operated as a single system. In this work we consider a VPP given by the aggregation of a cascade of hydropower stations (CHPS) connected at the High-Voltage (HV) grid and integrating a large portfolio of variable Renewable Energy Sources (VRES) connected at Medium-Voltage (MV) grids. Then, we tackle the problem of VPP profit maximization on the joint energy and ancillary services market, under complex technical constraint, safety constraints and unavailability of VPP resources due to faults. First, we propose a generic model of the VPP. Second, we present a two-level sequential VPP energy management strategy composed by long-term bidding optimization and real-time control via Economic Model Predictive Control (EMPC), both receiving forecast as input. Simulations employ realistic models and real forecast provided by the French aggregator Compagnie Nationale du Rhône (CNR). Compared to traditional Reference Tracking MPC (RTMPC), the EMPC increases by 6% the VPP profit and enhances the provision of ancillary services when faults occur.

INTRODUCTION

The high penetration of DER brings significant challenges for the stability and safety of the electrical grid due to the intermittency of VRES (e.g., wind and solar). The VPP concept provides an appealing solution to overcome these difficulties through the large-scale aggregation of DER operated as a whole to participate in multiple electricity markets and provide services to the grid operator.

Several studies have investigated the role that energy storage systems can play to compensate the intermittency and unpredictability of VRES [1], as well as enhance the provision of ancillary services [2]. As alternatives to electrochemical storage, hydroelectric reservoirs can be operated to enhance the integration of VRES. In particular, a CHPS not only represents a clean and reliable technology for power generation, but also provides the storage capacity required to mitigate the uncertainty of VRES. However, the energy management of such large-scale aggregations requires an effective combination of long-term scheduling, to optimize the VPP bidding strategy, and real-time control, to mitigate the effect of VRES uncertainty and faults. In [3], a chance-constrained optimization model for CHPS-VRES hybrid systems trading of energy and reserve is developed. In [4], the CHPS trading of ancillary services is modelled as a stochastic bilevel optimization problem. However, these contributions focus only on the bidding strategy and neglect the need of real-time control.

For real-time control, MPC has already proven its ability to provide efficient solutions. The traditional RTMPC is the most common MPC strategy and consists in minimizing the deviation between the controlled variables and their reference set-points. Such an MPC approach is used in [5], for hybrid photovoltaic-storage systems participation in the energy market, and in [6] for frequency control of microgrids operating in islanded mode. RTMPC is also employed in [7] for real-time control of a CHPS. However, RTMPC does not guarantee the optimization of the economic objectives in market-based problems.

To overcome this issue, a new tendency has arisen, known as EMPC, which directly optimizes the economic objectives in real-time, instead of tracking set-points. In [8], EMPC is employed to minimize the cost of storage degradation and electricity purchase of a microgrid. Similarly, in [9], an EMPC strategy is proposed to minimize the cost of deviations from the users demand, energy purchase and storage degradation of a microgrid. In the context of ancillary services provision, EMPC is employed in [10] for electrical vehicles participation in frequency regulation markets. However, either the participation in multiple electricity markets is neglected or the proposed real-time control strategies are applied to small-scale systems.

Therefore, the main contributions of this work compared to the related literature could be summarized as follows:

- We propose a two-level sequential architecture employing EMPC for real-time control, to cover the different time stages involved in the problem of VPP trading of energy and ancillary services, namely offering on the market and real-time control of the VPP.

- We consider a renewable-based VPP, where a CHPS provides storage capacity to compensate the intermittency and unpredictability of VRES. Then, we evaluate the benefits of this large-scale aggregation when participating in multiple electricity markets and the economic impact of faults in such a market-based problem.

Moreover, we present results obtained using real models, data and forecast, provided by the French aggregator CNR.

METHODOLOGY

Notation

We present discrete time problems over a finite set of sampling times $t \in T$ with sampling period Δ_T. We use ^ to denote the uncertain parameters of the problem, e.g., $\hat{P}$, and the superscripts LT and ST to denote long-term forecast and short-term forecast, respectively. Sets of decisions variables are denoted in **bold**, e.g., $\boldsymbol{z}$.

Modelling

In the following, we present the modelling of the market mechanism and the system dynamics.

Joint energy and ancillary services market

The aggregator is assumed to participate in the day-ahead market (DAM) to exchange energy and provide ancillary services. Up to 24h before the energy injection time, the VPP can submit bids on the DAM.

We denote by $E_{DAM}(t)$ and $\pi_E(t)$ the energy exchanged by the aggregator on the DAM and the energy price associated to the energy exchange, respectively. In real time, however, the VPP operator may face imbalances (differences between the original DAM offer and the actual energy injection in real-time) due to the unpredictability of VRES. The aggregator is assumed to be financially responsible for its imbalances. A penalty $\pi_E^{\uparrow}(t)$ is associated to negative imbalances (energy offer higher than the actual energy injection), denoted by $\Delta E^{\uparrow}(t)$, while positive imbalances (energy offer lower than the actual energy injection), denoted by $\Delta E^{\downarrow}(t)$, are rewarded with price $\pi_E^{\downarrow}(t)$ lower than the energy price.

Moreover, the VPP participates in the balancing ancillary services market (BASM) to provide primary frequency control. In particular, we consider the trading of Frequency Containment Reserve (FCR) [11]. The aggregator offers positive reserve (energy capacity to increase the injection of energy into the grid) and negative reserve (energy capacity to absorb energy from the grid). We denote by $R_{DAM}(t)$ and $\pi_R(t)$ the offer of FCR capacity and the FCR capacity price, respectively. FCR is modelled with a single variable since it is assumed to be symmetric (the offer of positive reserve equals the offer of negative reserve), as in many European BASMs (e.g., Germany) [12].

Cascade of hydropower stations

In the following, we propose a model which refers to the main characteristics of the CHPS operated by CNR [13]. Thus, we consider run-of-river hydropower plants, whose reservoir capacity is limited compared to the daily flow of the river. Each hydropower station is characterized by a set of turbines and a barrage. The former is used to generate power, while the latter is used to divert most of the water flow to the hydropower station. For safety reasons, the barrage is opened during flood periods to allow the natural flow of the river.

Denote by a a generic hydropower station in the set of many hydropower stations A. Then, the dynamics of the reservoir forebay water level Z are given by

$$Z(a,t+1) = Z(a,t) + [Q_{in}(a,t) - Q_{out}(a,t)]\Delta_T / SA(a), \tag{1}$$

$$Z(a,0) = Z^{init}(a), \tag{2}$$

where Q_{in} denotes the water inflow into the reservoir, Q_{out} denotes the water outflow and Z^{init} denotes the initial value of the reservoir water level. The notion of surface area, denoted by $SA(a)$, describes the relationship between the water discharge and the reservoir water level.

Denote by Q_{tr} and Q_{br} the water flow across the turbines and the barrage, respectively. Moreover, denote by $\hat{Q}_{ri}$ the water inflow from the river tributaries, which is assumed to be an uncertain parameter in the problem. Then, the total water inflow and outflow of asset a at time t are given by

$$Q_{in}(a,t) = Q_{br}(a-1, t-\tau_{a-1,a}) + Q_{tr}(a + - 1, t - \tau_{a-1,a}) + \hat{Q}_{ri}(a,t), \tag{3}$$

$$Q_{out}(a,t) = Q_{br}(a, t-\tau_{a,a+1}) + Q_{tr}(a, t + - \tau_{a,a+1}), \tag{4}$$

respectively. We denote by $\tau_{i,m}$ the time delay of water flow from the $i-th$ reservoir to the $m-th$ reservoir.

Hydraulic safety constraints play an important role in the operation of a real CHPS [13]. We include a safety constraint associated to the operation of the barrage. In particular, we enforce that the opening of the barrage can occur only when the water level has reached its maximum value Z^{max}. This is modelled by

$$Q_{br}(a,t) \le b_{br}(a,t) Q_{br}^{max}(a), \tag{5}$$

$$b_{br}(a,t) \le 1 + \frac{Z(a,t+1) - Z^{max}(a)}{Z^{max}(a)}, \tag{6}$$

where b_{br} denotes a binary variable.

In general, the power generation of each turbine depends on the hydraulic head, the turbine discharge and the plant efficiency [14]. However, assuming that the head variation is negligible, the power generation function is reduced to

$$P_H(a,t) = P^{max}(a) Q_{tr}(a,t) / Q_{tr}^{max}(a), \tag{7}$$

where $P^{max}(a)$ is the maximum power generation of a.

We enforce the following ramping limit:

$$|Q_{tr}(a,t) - Q_{tr}(a,t-1)| \le \Delta Q_{tr}(a), \tag{8}$$

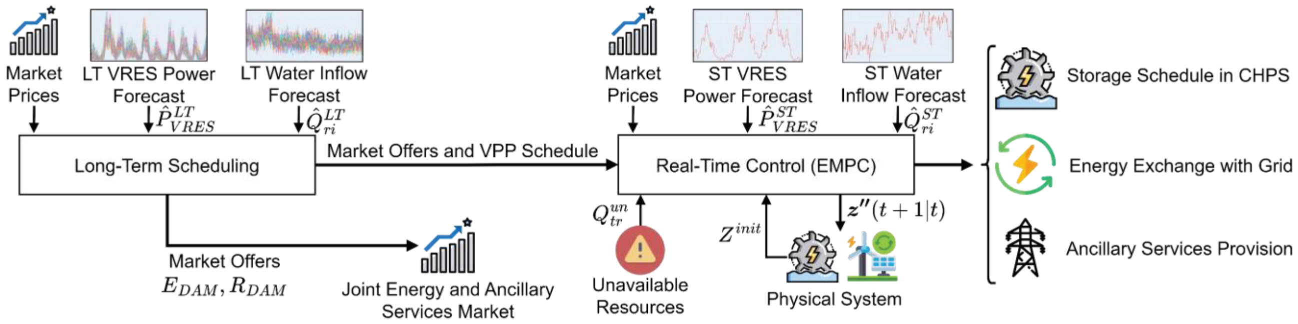

Figure 1: The proposed two-level sequential energy management strategy for VPP participation in the joint energy and ancillary services market.

where ΔQ_{tr} denotes the maximum allowed turbines discharge variation between consecutive time steps.
The acceptable ranges of reservoir water level, turbines and barrage water discharges are given by:

$$Z^{min}(a) \leq Z(a,t) \leq Z^{max}(a), \tag{9}$$

$$Q_{tr}^{min}(a) \leq Q_{tr}(a,t) \leq Q_{tr}^{max}(a) - Q_{tr}^{un}(a,t), \tag{10}$$

$$Q_{br}(a,t) \geq Q_{br}^{min}(a). \tag{11}$$

Turbines unavailability due to faults is modelled by means of the unavailable turbines water discharge capacity parameter, denoted by $Q_{tr}^{un}(a,t)$, which takes values between 0 (when all turbines are available) and $Q_{tr}^{max}(a)$ (when all turbines are unavailable).

VRES power
The VPP is assumed to integrate also several VRES power plants. We denote by $\hat{P}_{VRES}(t)$ the uncertain total power generation at time t of the VRES power plants.

Two-level architecture for trading and control

In the following we present our two-level sequential architecture for VPP trading of energy and FCR. The proposed architecture involves two levels:

1) **Long-term scheduling** of the VPP.
2) **Real-time control** of the VPP.

As shown in Figure 1, the long-term scheduling module employs long-term forecast of the uncertain parameters to compute DAM offers of energy and FCR. Then, based on short-term forecast, the EMPC strategy controls the VPP in real-time to optimize the economic objectives of the aggregator, provide ancillary services to the grid and cope with the unavailability of VPP resources due to faults.

First level: long-term scheduling
Define the following set of decision variables:

$$\mathbf{z}' = \{E_{DAM}(t), R_{DAM}(t), Z(a,t), Q_{br}(a,t), Q_{tr}(a,t) \mid a \in A, t \in T\}. \tag{12}$$

Then, the long-term scheduling of the VPP resources on the DAM is formulated as follows:

$$\underset{\mathbf{z}'}{\operatorname{argmax}} \sum_{t \in T} [\, \pi_E(t) E_{DAM}(t) + \pi_R(t) R_{DAM}(t) \Delta_T], \tag{13a}$$

subject to

$$E_{DAM}(t) + R_{DAM}(t)\Delta_T = \sum_{a \in A} P_H(a,t)\, \Delta_T + \hat{P}_{VRES}^{LT}(t)\Delta_T, \tag{13b}$$

$$(1) - (11), \tag{13c}$$

$$\forall t \in T, \forall a \in A. \tag{13d}$$

The two terms in Eq. (13a) represent the revenue of the aggregator from participating in the energy market and in the BASM, respectively. Eq. (13b) ensures the energy balance between market offers and VPP power generation.

Second level: real-time control
The second level of the proposed architecture tackles the VPP real-time control problem employing EMPC. Once the DAM session closes, market offers E_{DAM} and R_{DAM} are fixed. In real-time, deviations from the DAM offers (imbalances) are penalized by the market. To minimize the cost of imbalances and cope with the unavailability of turbines in the CHPS, we propose an EMPC strategy receiving short-term forecast ($\hat{Q}_{ri}^{ST}$ and $\hat{P}_{VRES}^{ST}$) as input.
Define the following set of decision variables:

$$\mathbf{z}'' = \{\Delta E^{\uparrow}(t+k \mid t), \Delta E^{\downarrow}(t+k \mid t), Z(a, t+k \mid t), Q_{br}(a, t+k \mid t), Q_{tr}(a, t+k \mid t) \mid a \in A,\ k \in K\}. \tag{14}$$

Then, the optimization problem solved at each time step $k \in K$ by the EMPC is formulated as follows:

$$\underset{\mathbf{z}''}{\operatorname{argmin}} \sum_{k \in K} [\, \pi_E^{\uparrow}(t+k)\, \Delta E^{\uparrow}(t+k \mid t) + - \pi_E^{\downarrow}(t+k)\, \Delta E^{\downarrow}(t+k \mid t)\,], \tag{15a}$$

subject to

$$E_{DAM}(t+k) + R_{DAM}(t+k)\Delta_K + - \Delta E^{\uparrow}(t+k \mid t) + \Delta E^{\downarrow}(t+k \mid t) = \sum_{a \in A} P_H(a, t+k)\, \Delta_K + \hat{P}_{VRES}^{ST}(t+k)\, \Delta_K, \tag{15b}$$

$$(1) - (11), \tag{15c}$$

$$\forall k \in K, \forall a \in A. \tag{15d}$$

Eq. (15a) represents the cost of imbalances. Eq. (15b) ensures the energy balance between market offers, imbalances and VPP power generation.

Benchmark approach

For the purpose of evaluating our method, we present a benchmark two-level architecture employing RTMPC for real-time control. The first level employs still (13) to compute DAM offers. However, differently from the EMPC-based approach, RTMPC controls the VPP in a price-unaware fashion.

Denote by $E_{RT}(t)$ the real-time exchange of energy with the grid (positive if the VPP injects energy into the grid, negative if the VPP absorbs energy from the grid).

Define the following set of decision variables:

$$\mathbf{z}''' = \{E_{RT}(t+k \mid t), Z(a, t+k \mid t), Q_{br}(a, t+k \mid t), Q_{tr}(a, t+k \mid t) \mid a \in A, k \in K\}. \tag{16}$$

Then, the optimization problem solved at each time step $k \in K$ by the RTMPC is formulated as follows:

$$\underset{\mathbf{z}'''}{\operatorname{argmin}} \sum_{k \in K} \left(E_{DAM}(t+k) - E_{RT}(t+k \mid t)\right)^2, \tag{17a}$$

subject to

$$E_{RT}(t+k \mid t) + R_{DAM}(t+k)\Delta_K = \sum_{a \in A} P_H(a, t+k)\,\Delta_K + \hat{P}^{ST}_{VRES}(t+k)\,\Delta_K, \tag{17b}$$

$$(1) - (11), \tag{17c}$$

$$\forall k \in K, \forall a \in A. \tag{17d}$$

Eq. (17a) represents the squared error term between the DAM offer and the real-time energy exchange.

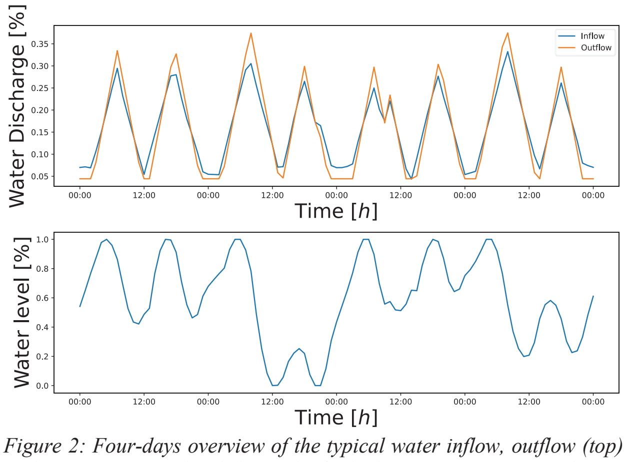

Figure 2: Four-days overview of the typical water inflow, outflow (top) and reservoir water level (bottom) of a hydropower station. Results are normalized between 0 and 1, which represent the minimum and maximum values of water discharge (top) and water level (bottom), respectively.

CASE STUDY

We study a real system composed by a cascade of three hydropower stations and a set of wind power plants. Simulations have been performed using historical time series of DAM prices in France. We use a single scenario of realization for each uncertain parameter of the problem ($\hat{Q}_{ri}$ and $\hat{P}_{VRES}$). To ensure confidentiality, the following results are scaled by the total capacity of the VPP. A simulation period of six months is considered (June 2017 - November 2017), with sampling period $\Delta_T = 1h$ for the long-term scheduling problem (13) and $\Delta_K = 15m$ for the real-time control strategies (15) and (17).

Operating a cascade of hydropower stations

As shown in Figure 2, the long-term scheduling strategy (13) is able to recognize the price pattern of the energy market. Thus, during peak price periods (typically around 08:00 – 10:00 and 18:00 – 20:00) the reservoir is emptied (water inflow ≤ water outflow) to produce slightly more energy than what is allowed by the natural inflow. Conversely, during low price periods (typically around 12:00 and during the night) water is stored in the reservoir (water inflow ≥ water outflow).

VPP market participation

Table 1 shows the normalized total net profit (difference between revenue and cost of imbalances) obtained with the EMPC-based and RTMPC-based strategies when trading energy only or energy + FCR. We consider two different configurations of the system: SYS1, where wind and CHPS are operated independently on the market; SYS2, where the aggregation of wind and CHPS is operated as a single system on the market.

	Energy only [€/MWh]		Energy + FCR [€/MWh]
Strategy	**SYS1**	**SYS2**	**SYS2**
RTMPC-based	56506.1	56739.9	58588.7
EMPC-based	59113.1	59365.1	62279.7

Table 1: Normalized total net profit obtained with the compared energy management strategies when trading energy only or energy + FCR.

In the energy only case, the EMPC is able to overcome the performances of RTMPC. Moreover, the profit increase obtained through the aggregation (SYS2) clearly shows that the storage capacity of the CHPS can be exploited to reduce the market penalties caused by VRES.

In the energy + FCR case, the EMPC shows a ~ 6% increase compared to RTMPC. Moreover, in the best case, we observe ~ 5% increase in the profit, compared to the energy only case, when participating also in the BASM.

Price sensitivity analysis

The following price sensitivity analysis is presented to show the difference between the price-aware EMPC strategy, compared to the traditional RTMPC. We consider imbalance price penalties computed as follows:

$$\pi_E^{\uparrow}(t) = (1 + \alpha^{\pi}) \cdot \pi^E(t), \tag{18}$$

$$\pi_E^{\downarrow}(t) = (1 - \alpha^{\pi}) \cdot \pi^E(t). \tag{19}$$

Table 2 presents the normalized total imbalances (sum of all imbalances scaled by VPP total capacity) obtained over the whole simulation period. While the EMPC-based architecture reacts to the increase of market penalties (higher values of α^{π}) by reducing the imbalances, RTMPC is insensitive to price variations (same imbalances $\forall \alpha^{\pi}$).

	EMPC-based [TOT imbalances/MWh]		RTMPC-based [TOT imbalances/MWh]	
α^{π}	$\Delta E^{\uparrow}$	$\Delta E^{\downarrow}$	$\Delta E^{\uparrow}$	$\Delta E^{\downarrow}$
0.5	228.6	207	205.2	56
1.5	228.3	206.8	-	-
2	227.1	205.7	-	-
3	226.7	205.4	-	-

Table 2: Normalized total imbalances obtained with the compared energy management strategies, for increasing values of market penalties.

Unavailability of VPP resources

In Table 3 we present the normalized total net profit obtained with the EMPC-based and RTMPC-based architectures, when faults occur in real-time on different developments of the CHPS. We consider two different scenarios: (I) 60% of unavailable turbines during seven random days, (II) 80% of unavailable turbines during fourteen random days. As shown in the table, still the EMPC-based architecture is able to outperform the traditional RTMPC-based approach. Moreover, we observe that the impact of faults on the first hydropower station of the cascade (HS1) is higher compared to that observed on the last development (HS3). This is due to the fact that faults affecting HS3 can be better mitigated exploiting also the upstream developments of the CHPS.

Fault scenario	Strategy	Fault on HS1 [€/MWh]	Fault on HS3 [€/MWh]
(I) 60%, 7 days	RTMPC-based	57327	57448.8
	EMPC-based	59923.7	60188.8
(II) 80%, 14 days	RTMPC-based	56679.7	56859.9
	EMPC-based	59284.6	59435.8

Table 3: Normalized total net profit obtained with the compared energy management strategies in different fault scenarios.

CONCLUSIONS

In this work we present a generic model of a VPP integrating VRES at MV grid and a CHPS at HV grid to participate in the joint energy and BASM. Then, we propose a two-level architecture employing EMPC to trade energy, FCR and control the VPP in real-time to maximize its economic objectives in fault scenarios, under complex technical constraints and safety constraints. Compared to the traditional RTMPC-based approach, our strategy is able to increase the VPP profit, as well as enhance the provision of ancillary services when faults occur. This work opens the way to further investigation in several directions. We plan to evaluate the performances of our approach when price forecast is used, instead of assuming known market prices. Moreover, the computational effort required to control in real-time such large-scale systems calls for alternatives to standard centralized optimization. Thus, distributed optimization can be employed to enhance the scalability, privacy and resilience of our approach.

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