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Integrating Distributed Energy: Value Stacking for PV with Power-to-Gas

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ABSTRACT

This analysis investigates the business case of a virtually aggregated unit with PV and power-to-gas, outlining the added value of enhanced operation modes for the integration of distributed energy resources. Such an aggregated unit can not only leverage the internal benefits of acting as a single unit, for example, by reducing imbalance errors and respective payments but also by offering a larger variety of products and services to the system than each unit could offer individually. Based on empirical generation and market data, the presented analysis outlines the added benefit of the so-called *value stacking* implementing the balance of forecast errors, the exploitation of short-term arbitrage opportunities, and the provision of secondary and tertiary frequency reserve. A multi-stage and multi-period optimization approach is presented to generate an aggregated bidding strategy on multiple energy and ancillary service markets. On the one hand, the results highlight the value of individual operation modes for the plant and, on the other hand, the aggregated benefit of value stacking with multiple combined operating modes. The provided empirical insights are beneficial for both potential investing parties that want to evaluate the potential value of combined plants and policymakers that consider further regulatory amendments to open markets and enable further integration of new energy sources.

Keywords: ancillary services, hydrogen, intermittent renewable energy, power to gas, value stacking, virtual power plant

1. INTRODUCTION

With the ongoing energy transition, the integration of renewable and Distributed Energy Resources (DERs) becomes key. The term "integration" is thereby usually used in two contexts. Either in the direct sense of opening further market segments to DERs by lowering entry barriers or in the indirect sense of allowing individual units to (virtually) aggregate with other units to a so-called Virtual Power Plant (VPP) and enter further market segments as such. However, only the combination of both concepts will leverage the full potential of DERs and generate a win-win situation at the macro- and microeconomic level for both system and individual plant operators [1]. Therefore, this analysis investigates the business case of a VPP, creating local synergies by aggregating one programmable and one non-programmable DER, i.e., a Photovoltaic (PV) unit and a Power-To-Gas (P2G) unit. Such an aggregated unit can leverage internal benefits, for example, by reducing imbalance errors and respective payments or by maximizing the valorization of low-cost electricity generation. On the other hand, it can generate external benefits by offering a larger variety of products and services to the system than each unit could offer individually. The resulting concept of providing multiple services simultaneously from a single flexible unit is called *value stacking* [2] or *revenue stacking* [3]. As of now, analyzed VPPs with value stacking usually consist of Battery Energy Storage Systems (BESS) with PV [4], [5]. However, such VPPs flexibility is limited by the inherent capacity limitations of BESS. It operates in a somewhat "closed-loop" flexibility cycle, meaning that all service provided in one direction is limited in time and must be accompanied by some operation in the opposite direction before being able to re-provide the same service again [6]. VPPs with P2G units instead offer a wider flexibility range and operate in a somewhat "open loop" flexibility cycle, meaning that any service can be provided without specific time limitations [7]. In the further course of the paper, the material and methods are presented, the model simulation is outlined, and finally the results of value stacking are presented and discussed.

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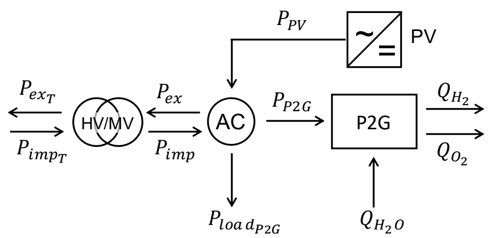

Fig. 1. Scheme of the modeled VPP

2. MATERIAL AND METHODS

The modeled VPP consists of a 20 MW_{peak} PV unit and a 6.2 MW_{peak} P2G unit connected at medium voltage level. The model considers combined operation on the Day-Ahead Market (DAM), the Intraday market (IDM), and Balancing Market (BM) in the Italian market zone of Sicily. To comply with current Italian regulations for virtual aggregation, it is assumed that the two units share the same primary substation. However, without loss of generality, the two units could be also be located at two different grid connection points. A schematic representation of the modeled VPP is shown in Fig. 1.

For the PV plant, operational data is extrapolated from the PV forecast and actual generation of the market zone of Sicily. Data is publicly available through the transparency portal of the European transmission system operators ENTSO-E [8]. For the P2G plant, operational data of a plant with identical dimensions as in the Mainz Energy Park is used. The corresponding model input parameters are reported in Table 1.

While the regulatory framework for P2G units is not yet fully developed, it is assumed that such a unit will purchase electricity from the spot market. Publicly available market data is used as model input, public through the Italian market operator GME [9]. The DAM is settled in a single session on a pay-as-cleared basis, resulting in one single price per market zone and time period. The IDM is also settled with a pay-as-cleared approach but consists of multiple sessions and multiple clearing prices per time period. The BM, on the contrary,

Table 1. Applied P2G model characteristics

Model parameter	Value	Reference
Rated power	3.75 MW	[10]
Peak power	6.20 MW	[10]
Min power	1.00 MW	[10]
Efficiency* at rated power	55%	[11]
Efficiency* at peak power	49%	[11]
Efficiency* at min power	65%	[11]
Stand-by consumption	0.001 MW / MW_{rated}	[11]
Demineralized water consumption	9kg /kg_{H2}	[12]
Demineralized water costs	0.0007 €/kg	[12]

* with regard to lower heating value, incl. all auxiliaries

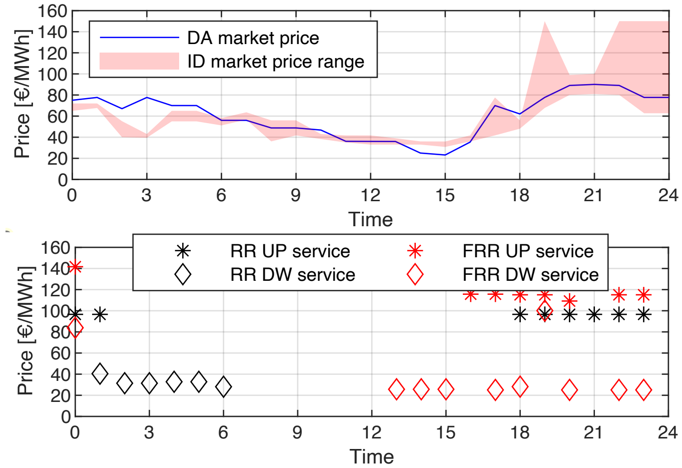

Fig. 2. Day-ahead and intraday prices (chart above) as well as balancing market prices (chart below) on one exemplary day (07.07.2019) in the Italian market zone of Sicily

is settled on a pay-as-bid basis and a weighted average price per product category and time period is derived based on a methodology as described in [1]. The resulting market prices for an exemplary day in July 2019 are presented in Fig. 2. Furthermore, it is assumed that the P2G unit will pay grid charges as other medium voltage connected large consumers while being exempted from additional taxes or levies for not being an electricity end-user. Respective grid charges resulted in being 15.77 €/MWh for 2019 [13]. On the Hydrogen (H2) side, no spot market exists, which is why a fixed sales price of 4 €/kg_{H2} was assumed in line with the current average of renewable H2 projects in Europe [14].

3. MODEL CALCULATION

The VPP and its operation are modeled in Matlab using YALMIP and Gurobi as a solver for multi-stage and multi-period optimization. Simulation is performed with an hourly resolution for four exemplary days, one day each during the week and on the weekends in summer and winter. The VPPs service orchestration follows the market session sequences, and operational decisions are purely guided by market conditions through price signals. As this analysis focuses on the benefits of value stacking and not on optimal forecasting techniques, perfect market price forecasting is assumed in a first approximation. The optimization goal is, therefore, to minimize operational costs and maximize revenues for every time period.

Starting with the day-ahead forecast of PV and DAM prices as input parameters, the first optimization decision is selling PV generation either on DAM or consuming it through the P2G unit, converting it to H2.

Furthermore, the P2G unit might also purchase electricity directly from the grid if market prices are conveniently low.

After the conclusion of this first phase, day-ahead forecast error applies, and the PV profile is updated. Furthermore, the VPP faces new prices through the multiple IDM sessions. Thus, the model optimizes the operation by balancing the forecast error either by adjusting the P2G profile or buying/selling the energy difference to/from the IDM and potentially further adjusting the P2G profile based on market conditions.

After the energy market sessions conclude, the VPP can decide to offer balancing services on the BM according to its adjusted baseline. The adjusted baseline is the resulting grid exchange profile at the substation, being the sum of PV and P2G profiles from all previous energy market operations. Tertiary reserve, called Replacement Reserve (RR) in ENTSO-E terminology, is offered either in upward or downward direction. As before, perfect price forecasting and full offer acceptance are assumed, in a first approximation, for individual offers based on the weighted average price of actually accepted offers at the market zone level.

In a fourth and last step, the VPP can offer additional balancing services in terms of the faster secondary reserve, called Frequency Restoration Reserve (FRR) in ENTSO-E terminology. Other services such as primary reserve or the sale of oxygen as the byproduct of electrolysis are not considered by now, although being a potentially valuable additional revenue stream [11]. Also, locational sensitive services such as congestion management are not considered.

4. RESULTS AND DISCUSSION

With the H2 sales price of 4 €/kg$_{H2}$, the resulting marginal price for which the P2G unit starts operating is a spot market price of 78.00 €/MWh. Below this price, the VPP will begin to consume the PV generation through the P2G unit, above this price rather sell to the grid. As the P2Gs efficiency decreases with increasing load, the price needs to fall below 58.20 €/MWh until the P2G unit consumes PV generation with full (peak) capacity. Given the additional grid charges for consumed electricity, the spot market price must fall furthermore even below the price of 62.23 €/MWh before the VPP starts purchasing electricity from the grid for H2 generation if no PV generation is available.

For the exemplary summer weekend day of 07.07.2019, VPP operation on DAM results in absorption of PV generation through the P2G units, varying with PV availability and DAM prices as shown in Fig. 3. Only from 06:00 to 07:00, the VPP will import electricity from the grid since market prices are sufficiently low. At the same time, PV generation is not yet sufficient to fill the minimum operation requirement of 1 MW for the P2G unit on its own. During the night hours, where no PV generation is available, DAM prices are, on the contrary, too high to operate the P2G unit. Notable also the reduction of P2G consumption with a respective increase of PV export to the grid during the high price hour from 17:00 to 18:00. The otherwise inelastic PV generation transforms thereby thanks to the aggregated P2G flexibility to a price-responsive unit. This is beneficial both for the overall system operation and for individual unit operation. The PV unit by itself would generate on

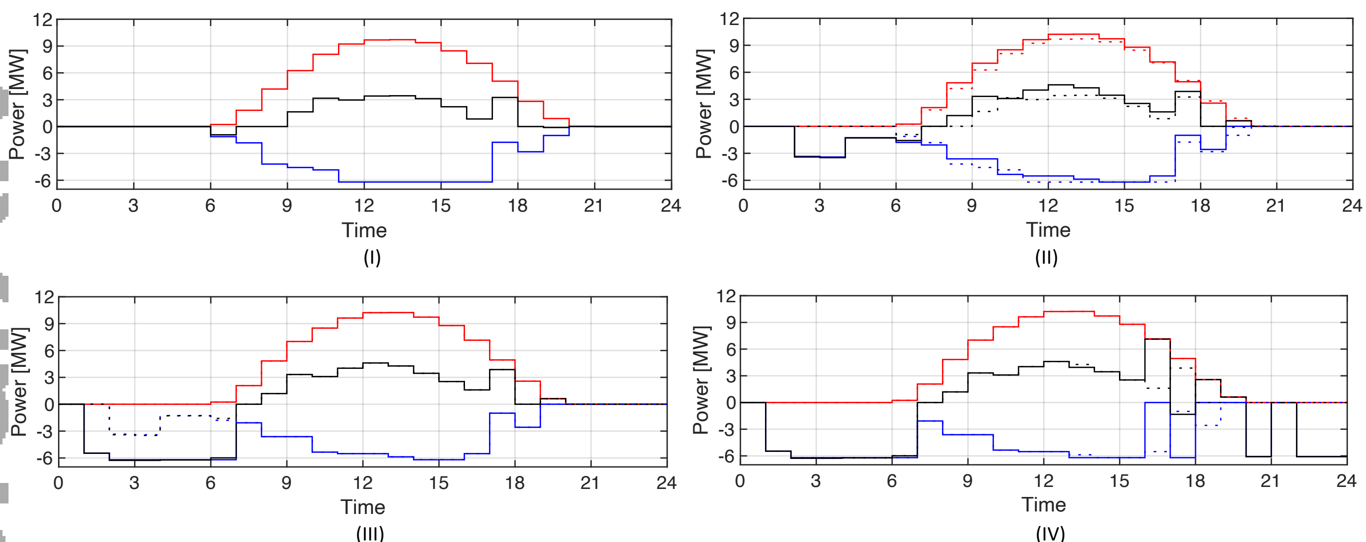

Fig. 3. PV generation profile (red line), P2G load profile (blue line), and resulting grid exchange profile (black line) of modeled VPP on one exemplary day (07.07.2019), offering (I) on DAM only, (II) adjusting PV forecast errors on IDM, (III) offering RR on the BM, and (IV) offering FRR on the BM. Dotted lines represent the result from the previous optimization stage.

Table 2. Operational results for each of the four operation modes for the VPP or its individual units as result of the multi-stage, multi-period optimization of VPP operation on four exemplary days in 2019

	DAM: baseline	IDM: adjustment		BM: RR provision		BM: FRR provision		Total: value stacking	
Weekday Winter (02.01.2019)	2,055 €	+1%	+28 €	+33%	+676 €	+20%	+416 €	+54%	3,174 €
Weekend Winter (06.01.2019)	2,402 €	+13%	+321 €	+73%	+1,761 €	+18%	+436 €	+105%	4,919 €
Weekday Summer (03.07.2019)	5,575 €	+17%	+965 €	+7%	+395 €	+40%	+2,239 €	+64%	9,174 €
Weekend Summer (07.07.2019)	4,592 €	+7%	+306 €	+11%	+496 €	+25%	+1,165 €	+43%	6,559 €

that day revenues of 1,645€ selling all generation to the spot market. Conversely, the P2G unit would earn 240€ if generating H2 only from non-PV-generated electricity through the grid. In combined VPP operation, the overall revenue increases to more than the simple sum of both individual revenues, resulting in 2,055€ as reported in Table 2.

With the adjustments of the day-ahead PV forecast error in the subsequent time step, the optimization modifies the P2G profile concerning the new IDM prices. As visible in Fig. 3 (II), from 10:00-11:00, the additional PV generation is, for example, absorbed by the P2G unit, whereas from 08:00-10:00 additional PV generation is sold to the spot market instead. Dotted lines in the figure represent the respective unit profiles from the previous DAM session, solid lines represent the updated profile from IDM operation. Given that the IDM features higher prices for those two hours than the DAM, the P2G unit even decreases its consumption and the VPP further increases its overall export to the grid. Moreover, the comparably lower IDM prices in the early morning hours drive the VPP to absorb a notable amount of energy through the P2G unit outside hours of PV generation. Revenues of the overall operation on the day are increased by 7% through IDM optimization.

In the third stage, BM operation is introduced with RR provision. The possibility of obtaining additional energy in the very conveniently low price range from 25-40€/MWh drives the VPP to increase absorption from the grid in early morning hours through Downward (DW) services. Upward (UP) services are not possible in these hours, even though demanded by the market since the VPPs baseline is zero and no energy export is possible without PV generation. Revenues are increased through the provided RR services by an additional 11% compared to the DAM operation.

Integrating additional FRR services in the fourth and last optimization step mainly changes the VPP grid exchange profile for the evening hours. These are hours when the market demands neither RR services nor FRR prices are more convenient than those for RR services. In hours where the VPP has a sufficiently substantial P2G load, such as for example from 16:00-17:00 or 18:00-19:00, UP services provision results economically convenient. Hours with lower P2G load instead, such as, for instance, from 17:00-18:00, are prone to DW services despite the conveniently high UP prices per MWh. FRR services add thereby an additional 25% of revenues, summing up to a total of 6,559€ from value stacking for the exemplary day of 07.07.2019. For the four simulated exemplary days in 2019 value stacking adds thereby at least 43% compared to DAM revenues. Contributions of the different markets depend thereby on the underlying forecast errors, balancing services demand and respective prices as shown in Table 2.

5. CONCLUSIONS

The operation of an aggregated unit composed of PV and power-to-gas is simulated with a multi-period and multi-stage optimization approach to assess the value of providing multiple services from distributed energy resources. The case study is based on empirical market data from Italy and operational parameters from an existing power-to-gas unit. The combined operation of aggregated units proves beneficial to individual unit operation and turns previously inelastic units price responsive. The results highlight the operational interdependencies of different service provisions and show that value stacking adds at least 43% of potential revenues compared to mere day-ahead market operation for the four exemplarily analyzed days.

Future research opportunities include, among other things, i) the leverage of additional internal benefits such as real-time balancing of fluctuating non-programmable generation, ii) the leverage of additional external benefits from the provision of additional services such as primary reserve, and iii) enhanced optimization approaches with cross-market arbitrage.

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