Sensitivity Analysis of Peer-to-peer Photovoltaic Energy Trading in a Community Microgrid in Chile

Javier Salles-Mardones, Alex Flores-Maradiaga, Rodrigo Barraza, and Mohamed A. Ahmed

Abstract—Nowadays, public policies in Chile are geared towards the promotion of distributed energy resources (DERs) such as distributed photovoltaic (PV) systems. However, the prevailing socioeconomic context and the lack of incentive to invest in DERs have posed a challenge to achieving the established goals in the coming years. This paper develops a three-entity architecture model and decision-making algorithms for peer-to-peer (P2P) PV energy trading. It seeks to conduct a sensitivity analysis of a P2P PV energy trading system in a community microgrid, to assess the potential benefits for local communities and to encourage the development of new local public policies aimed at enhancing the profitability of DERs. Various scenarios are compared, both with and without P2P market, considering residential customers (RCs), encompassing both consumers and prosumers with PV systems, with or without battery energy storage systems (BESSs), an aggregator (AG), and utility grid (UG). Daily energy and economic transactions are examined with the aim of reducing the annual electricity bills for each RC, enhancing the profitability of DERs for prosumers, increasing incomes for the AG, and exploring potential benefits for the UG. The load profiles and meteorological data are collected from publicly available databases, and a novel electricity pricing scheme is proposed based on current rates offered by the local UG. The results demonstrate that the P2P market could lead to a reduction in the annual electricity bills by as much as 1.76% for consumers, an increase in annual income of up to 149% for prosumers, and a reduction in the payback period for their DERs by up to 0.4 years. This paper contributes to improving the investment in DER projects and provides a guide for extending the work to different regions of Chile and global emerging economies with DER potential.

Index Terms—Battery energy storage system (BESS), microgrid, peer-to-peer (P2P) market, photovoltaic (PV) system, residential customer.

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I. Introduction

CHILE is undergoing an energy transition process to achieve sustainability in its energy sector and diversify the energy matrix towards renewable energy sources, taking advantage of the local abundant solar and wind resources. Public policies have been implemented, including the commitment to achieve carbon neutrality by 2050, and the governmental programs, such as Casa Solar, which aimed to promote investments in small distributed photovoltaic (PV) systems for households with low assessed property values. These policies not only reduce the investment required to improve the transmission system, which cost about 279 million USD in 2023 [1], but also avoid the installation of large-scale renewable generation plants. These plants often encounter socio-environmental obstacles and substantial levels of curtailment, which accounted for 7.63% of their generation in 2022, due to limitations in the existing transmission system [2]. However, both international and local factors have slowed the process and affected the base generation of the power system. Between 2019 and 2022, the coal prices have increased by 242%, oil by 53%, and liquefied gas by 600%. Furthermore, Chile has experienced a local severe drought over the past decade, resulting in a 26% reduction in hydroelectric generation between 2019 and 2021, which typically accounts for approximately 20% of the total generation of the power system [3].

The increases in demand have affected transmission systems, which require the construction of new infrastructure, estimated at a cost of around 850 USD/(MW·km^{-1}) [4]. Local inflationary crisis has also led to an increase in input costs for generation projects, affecting its profitability [5]. By 2040, the optimal installation of distributed generation (DG) in Chile is projected to reach around 6.22 GW, constituting 40% of the newly installed generation capacity in the power system [6]. However, the current level of DG implementation is far from this value, due to the lack of information available to residential customers (RCs) regarding the benefits of DG projects and the low internal rate of return (IRR) for potential investors. It is crucial and essential to encourage the private investment and consider transitioning from the existing system with fixed electricity rate to a dynamic one that accurately reflects real-time demand.

The global trends in microgrids and local peer-to-peer (P2P) markets could be locally implemented, allowing RCs to exchange surplus PV output among themselves [7]. This arrangement has the potential to offer more substantial com-

pensation for surplus generation, thereby significantly enhancing the profitability of distributed energy resource (DER) projects. Moreover, P2P markets offer several benefits such as enhancing operational efficiencies of distribution grid, increasing resilience and flexibility of the electrical system to avoid failures, reducing dependence on high-voltage transmission, improving supply quality indices, minimizing losses caused by inversions of power flow direction in the distribution grid, and contributing to stabilizing the utility grid (UG) frequency [8].

Various studies have been conducted on the implementation of P2P markets outside of Chile. In [9], a P2P energy trading model was proposed, which uses a virtual consumer management system in the UG that operates in real time. Simulations were conducted in a microgrid featuring four RCs with small PV systems. The model aimed to maximize profits for participants and to enhance the return on investment (ROI). In [10], the advantages of P2P trading for RCs in a community microgrid with 100 to 300 households were explored. Market paradigms such as bill sharing, mid-market rate, and auction-based pricing were introduced. The results showed that a moderate PV penetration in P2P energy trading, coupled with diverse demand profiles, led to a significant 30% reduction in electricity bills.

In [11], a cost-effective energy trading system was suggested for an off-grid community with DERs. Each house consists of a PV system, battery energy storage system (BESS), and Intenet of Things serving for real-time energy data management. In [12], a cooperative mechanism centered on the user was developed to encourage the user involvement in P2P energy trading. An experiment was conducted in a residential community with 19 households, involving real-time measurements of demand, PV generation, and BESS status. The results showed that the average P2P market price is approximately 27% lower than the UG price. In [13], the potential benefits of P2P markets for 75 households integrating DERs were studied. Data on load, PV generation, and BESS status were collected. Real-time pricing for the UG was assumed. The results indicated that consumers can reduce their electricity bills by up to 27.3%, decrease reliance on the UG, enhance self-sufficiency, and optimize BESS usage during more profitable time periods.

In [14], a P2P energy trading system was proposed, which virtually matches energy supply and demand, while in the physical layer, energy flows are traded using the existing UG. The results demonstrated that the P2P system could effectively and reliably transmit energy in a community microgrid with 20 households and 1 office. In [15], the P2P energy transactions among 3 households with PV systems were compared with conventional methods. Weather and load data were collected, and the actual electricity transactions were facilitated by the UG as an intermediary, which charged a fee. The results favored P2P trading as the most cost-effective approach, as it enables RCs to remain in lower consumption tariff ranges. In [16], a P2P energy trading model was introduced, considering PV generation and BESS. Thirty different buildings were divided into groups with PV plus BESS, only PV, only BESS, and none of the above. Participants placed buying or selling orders in the P2P market, with a microgrid operator overseeing transactions, managing microgrid consumption, and setting market prices. The results showed that the P2P market empowers households to invest in local PV systems.

In [17], the study assessed the impact of local regulatory frameworks on P2P markets. The initial designs were economically unattractive to RCs due to high public taxes on the use of the UG infrastructure. A novel market design was proposed incorporating a few legal adjustments. Simulations included 14 households, a large PV plant, and a microgrid operator. Data on electricity prices, PV generation, and load were collected. The results indicated that the proposed model enables the community to benefit from the P2P market. In [18], various strategies to incentivize microgrid development were examined in smart energy communities, considering architectural layers, DERs, UG integration, and local electricity markets. In [19], a hierarchical blockchain architecture was developed for an electric vehicle-to-grid trading system. It facilitates intelligent electric vehicle (EV) charging and discharging schedules to contribute to the UG load regulation and ensure fair benefit distribution among EV owners, aggregators (AGs), and the UG. Table I summarizes and compares previous research works on P2P energy trading.

The research on P2P energy trading is an emerging topic attracting a lot of attention with many research works and trial projects across the world [20]-[22]. To implement such solutions, it is essential to define the responsibilities and roles of consumers in the P2P market, as well as to develop the P2P market policies and economic incentives for energy trading [20]. Also, there is a need for policies and regulations to incentivize the participation of DERs in the local energy market [21]. Furthermore, there is a need to analyze how BESS would impact the outcomes of prosumers with PV systems [22].

In the context of Chile, current local regulations do not permit the implementation of P2P markets. This restriction is primarily attributed to the absence of studies advocating for the adoption of P2P energy trading and the lack of assessments regarding its potential benefits. An assessment of this nature has the potential not only to strengthen existing public energy policies such as Casa Solar program, but also to stimulate the formulation of new policies geared towards enhancing the profitability of DG projects. This, in turn, could result in benefits not only for prosumers but also for consumers, potentially leading to reductions in their electricity bills.

This paper aims to carry out a sensitivity analysis of local PV energy trading in a community microgrid in Chile. The main contributions are given below.

1) Develop an architecture model for the local energy trading in a community microgrid. This includes the definition of the main entities of participants and a new model for electricity prices based on the current retail prices set by the local utility company for the energy trading market.

2) Perform a sensitivity analysis for the local energy market considering RCs with PV and BESS. The meteorological data and electricity consumption profiles for end users are considered for a real case study in Viña del Mar, Chile.

TABLE I
SUMMARY OF PREVIOUS RESEARCH WORKS ON P2P ENERGY TRADING

Reference	Year	Location	Main contributions or results	Participants	Specifications	
					Data collection	DERs
[9]	2021	South Korea	Maximized profits and improved ROI are achieved for prosumers and consumers	4 households	Load: real-time dataset PV generation: theoretical estimation Electricity prices: local bills	PV: installed power of 0.4-7.5 kWp
[10]	2017	UK	Community electricity bills are reduced by 30%	10-300 households	Load: real-time dataset PV generation: real-time dataset	PV: peak power generation of 2-3.5 kWp
[11]	2022	Pakistan	P2P market is implemented in an off-grid community	10 households	Not applicable	Not applicable
[12]	2021	Japan	P2P market price is 27% lower than the UG price	19 households	Load: real-time dataset PV generation: real-time dataset Electricity prices: power market price	PV: installed power of 4.2-7.2 kWp BESS: capacity of 9.8 kWh
[13]	2022	USA	Prosumer bills are reduced by up to 27.3% and self-consumption is increased	75 households	Load: real-time dataset PV generation: real-time dataset Electricity prices: real-time power market prices	
[14]	2021	Japan	P2P system could securely and stably transmit energy	20 households and 1 office		BESS: capacity of 9.8 kWh
[15]	2020	South Korea	P2P system maintains lower electricity prices than grid prices and avoids energy injection into grid	3 households	Load: theoretical estimation PV generation: theoretical estimation Electricity prices: progressive rate system Weather data: Meteonorm software	PV: installed power of 3 kWp
[16]	2020	China	P2P system encourages users to invest in PV systems and increase self-consumption	30 households	Load: real-time database PV generation: theoretical estimation	PV: installed power of 595 kWp
[17]	2020	Germany	P2P market model adapts to regulatory frameworks and allows communities to obtain benefits	14 households and 1 PV plant	Load: real-time database PV generation: open-source database Electricity prices: local bills	PV: installed power of 1.2-4.1 kWp for households and 100 kWp for PV plant BESS: capacity of 4-6 kWh
[18]	2022	Ireland	Different approaches are used to incentive microgrid development in smart communities	Not applicable	Not applicable	Not applicable
[19]	2022	China	Blockchain architecture for an EV-to-grid system is applied, which generates benefits for participants	360000 EVs and 240 AGs	Load: randomly generated state of charge (SoC) for EVs Electricity prices: different price periods during the day and incentives for frequency response	EV battery: capacity of 40 kWh EV charger: power of 7 kW
This paper	2023	Chile	Sensitivity analysis of local P2P PV energy trading in a community microgrid is conducted, allowing for an economic estimate in the current context (fixed pricing system, net metering, and solar resource)	4 households	Load: annual consumption profiles of 3.7 MWh and 3 MWh from theoretical estimation Electricity prices: local bills Weather data: open-source database	PV: installed power of 4.92 kWp and 4.1 kWp BESS: capacity of 10.56 kWh

3) Compare the results of the local energy trading with a conventional scenario, analyzing the profitability improvements for DG projects of prosumers, the reduction in electricity bills for RCs, and the potential benefits for both the AG and UG.

II. METHODOLOGY

A. Proposed Scheme

The proposed scheme corresponds to an adaptation of the architecture proposed in [19]. Although the architecture was developed for the energy trade from EVs, the architecture has a modular design that can be applied and adapted to different scenarios. Figure 1 shows the main entities of the P2P energy trading system. The primary participants include the UG, AGs, and RCs (consumers and prosumers with PV systems with or without BESS). The UG establishes energy contracts with the AGs, whereas the latter maintain contracts with RCs and oversee the coordination of the P2P market. The direction of the flows indicates the payments that are being made.

B. Trading Contracts of RCs

RCs are responsible for paying their energy consumption to their AG, whereas the AG must compensate RCs for their energy injections. The total cost C_T^R for an RC is determined as:

$$C_T^R(t) = C_{EC}^{AR}(t) - C_{EI}^{RA}(t) \tag{1}$$

where C_{EC}^{AR} and C_{EI}^{RA} are the costs of energy consumption from AG and energy injection into AG, respectively.
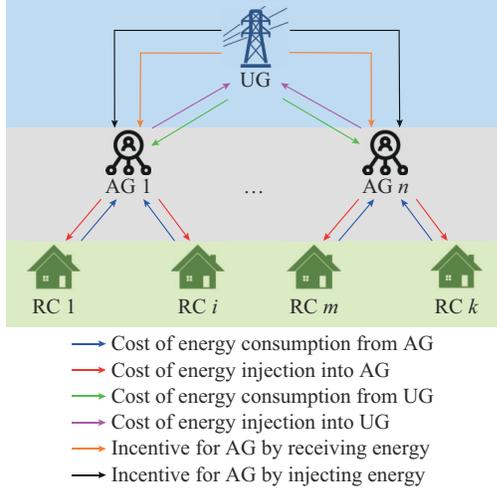
C_{EC}^{AR} is determined as:

Fig. 1. Schematic diagram for main entities of P2P energy trading system.

$$C_{EC}^{AR}(t)=\int_{t_s}^{t_e} r_C(t)P_{PC}^{AR}(t)W_{EC}^{PR}\mathrm{d}t + \int_{t_s}^{t_e}(1-r_C(t))P_{PC}^{AR}(t)W_{EC}^{UR}\mathrm{d}t \quad (2)$$

where t_s and t_e are the initial instant and the end of defined time interval, respectively; r_C is the fraction of energy consumed from the AG that is imported from the P2P market, while the remainder is imported from UG; P_{PC}^{AR} is the power consumed from the AG; W_{EC}^{PR} is the unit price of energy imported from the P2P market; and W_{EC}^{UR} is the unit price of energy imported from the UG.

C_{EI}^{RA} is determined as:

$$C_{EI}^{RA}(t)=\int_{t_s}^{t_e} r_I(t)P_{PI}^{RA}(t)W_{EI}^{RP}\mathrm{d}t + \int_{t_s}^{t_e}(1-r_I(t))P_{PI}^{RA}(t)W_{EI}^{RU}\mathrm{d}t \quad (3)$$

where r_I is the fraction of energy injected into the AG that is sold in the P2P market, while the remainder is injected into the UG; P_{PI}^{RA} is the power injected into the AG; W_{EI}^{RP} is the unit price of energy sold in the P2P market; and W_{EI}^{RU} is the unit price of energy injected into the UG.

1) PV Generation Estimation

Local PV generation is calculated for prosumers. Table II summarizes the assumed parameters for PV systems, which were obtained from previous works [23], [24].

The effective PV power generation P_{PV} is determined as:

$$P_{PV}(t)=NL_f Y(t)(TP_{PV}(t)+PL_t(t)) \quad (4)$$

where N is the number of installed PV panels; L_f is the factor of system power loss, encompassing losses due to dust, shading, and electrical wiring; Y is the guaranteed yield of PV panels by the manufacturer; TP_{PV} is the power generation without factoring in losses; and PL_t is the power losses attributed to thermal effects in PV panels. TP_{PV} is determined as:

$$TP_{PV}(t)=G_t(t)\cdot EA_{PV}\cdot n_{PV} \quad (5)$$

Meanwhile, PL_t is determined as:

$$PL_t(t)=\frac{PTC}{100}(CT(t)-NOCT)\cdot TP_{PV}(t) \quad (6)$$

where PTC is the loss coefficient attributed to variations in temperature of PV cell concerning $NOCT$; and CT is the cell temperature of PV panel, which is determined as:

$$CT(t)=T_{Amb}(t)+\frac{\alpha G_t(t)}{U}(1-n_{PV}) \quad (7)$$

2) PV Systems and BESS Dimensioning

PV systems are dimensioned based on the day with the highest load during the year, as given in (8) [23].

$$N=\frac{L_{cr}}{E_{cr}} \quad (8)$$

where L_{cr} is the highest daily load in the year; and E_{cr} is the energy generated by a PV panel on the critical day. Besides, the dimensioning of BESS is carried out as given in (9) [25].

$$RC_{BESS}=\max_{0\le k\le TNP}\left(\sum_{i=0}^{j}L^i-\sum_{i=0}^{j}P_{PV}^i\right) \quad (9)$$

where TNP denotes the periods that commence and conclude moments when local generation P_{PV}^i equals the load L^i. In simpler terms, these are time intervals where L^i exceeds P_{PV}^i. Consequently, j represents the number of time steps within the kth period. Consequently, the required capacity of the BESS RC_{BESS} corresponds to the highest value of the difference between the total load and local generation across all periods. Table III summarizes the assumed BESS parameters for the RCs, derived from previous works [23], [26].

TABLE II
PARAMETERS FOR PV SYSTEMS

Parameter	Symbol	Value or unit
Incident global irradiance*	G_t	W/m^2
Ambient temperature*	T_{Amb}	°C
Factor of thermal losses	U	29 W/(m^2·°C)
Factor of PV system losses	L_f	0.7
Efficiency of PV panel	n_{PV}	20%
Rated power of PV panel	RP_{PV}	410 Wp
Effective area of PV panel	EA_{PV}	1.81 m^2
Absorption coefficient	α	0.9
Temperature variation loss coefficient	PTC	−0.36% per °C
Rated temperature of PV cell	$NOCT$	45 °C
Yield loss due to panel degradation	Y_L	0.64% per year
Initial guaranteed yield	Y_i	97%

Note: * represents data from local database [24].

TABLE III
BESS PARAMETERS FOR RCs

Parameter	Symbol	Value
Technology		Lithium-ion
Lifecycle		4500 cycles
Estimated lifespan		12.3 years
Initial SoC		20%
Capacity of battery bank	B_c	10.56 kWh
Standby losses	S_l	1% per hour
The maximum SoC	Ma_s	99%
The minimum SoC	Mi_s	20%
Charging efficiency	C_e	90%
Discharging efficiency	D_e	90%
The maximum charging power	M_c	30% of total capacity
The maximum discharging power	M_d	30% of total capacity

3) Home Energy Management System (HEMS) Algorithms

The HEMS algorithm determines power transactions with the AG (P_{PC}^{AR} and P_{PI}^{RA}) and self-consumption (S_c), using input parameters such as P_{PV}, electrical load (L), and the SoC of BESS (SoC). Two distinct HEMS algorithms are employed, one designed for prosumers without BESS and the other for those with BESS.

Algorithm 1 summarises the logic behind an HEMS designed for prosumers without BESS. At each time step t, two possible decisions are considered depending on the presence of power surpluses or deficits, as shown in Fig. 2.

Algorithm 1: HEMS algorithm for prosumers without BESS

Input: P_{PV} and L
Output: P_{PC}^{AR}, P_{PI}^{RA}, and S_c
1: **for** $t=0$ to T **do**
2:   **if** $P_{PV} \geq L$ **then**
3:     $P_{PC}^{AR}=0$, $P_{PI}^{RA}=P_{PV}-L$, and $S_c=L$ (Decision A)
4:   **else**
5:     $P_{PC}^{AR}=L-P_{PV}$, $P_{PI}^{RA}=0$, and $S_c=P_{PV}$ (Decision B)
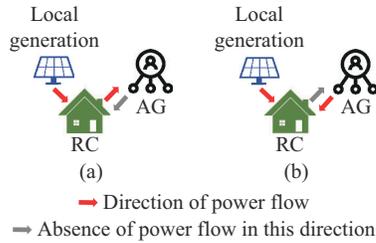6:   **end if**
7: **end for**

Fig. 2.   Schematic diagram illustrating potential HEMS decisions for prosumers without BESS. (a) Decision A. (b) Decision B.

Algorithm 2 summarises the logic behind an HEMS for prosumers with BESS. At each time step t, seven possible decisions are considered depending on the availability of surplus power, power deficits, and BESS constraints (see Fig. 3). In Fig. 3, Decisions A-G have the following features.

1) Decisions A and C: local PV generation covers the load, and surplus is stored in the BESS.

2) Decision B: a fraction of local PV generation covers the load, another fraction fully charges the BESS, and surplus is injected into the AG.

3) Decision D: a fraction of the load is supplied by local PV generation, and the rest comes from the BESS.

4) Decisions E and G: the load is partially met by local PV generation, the BESS, and the AG.

5) Decision F: a fraction of the load is covered by local PV generation, while the rest is provided by the AG.

4) Proposed Electricity Price Market

In Chile, whereas the distribution sector is intended to be competitive, there are only two main distribution companies that serve the majority of customers. The purchase of long-term contracts helps the distribution companies maintain the market power. This directly impacts customers, as distribution companies play the dual role of both distributor and retailer, explaining why fixed prices persist.

Algorithm 2: HEMS algorithm for prosumers with BESS

Input: P_{PV}, SoC, and L
Output: P_{PC}^{AR}, P_{PI}^{RA}, S_c, and SoC
1: **for** $t=0$ to T **do**
2:   $SoC'=SoC-S_l$
3:   **if** $P_{PV} \geq L$ **then**
4:     $\Delta P = P_{PV}-L$, $P_{PC}^{AR}=0$, and $S_c=L$
5:     **if** $\dfrac{B_c M_c}{100} \geq \Delta P$ **then**
6:       **if** $SoC'+ \dfrac{C_e \Delta P}{B_c} \leq Ma_s$ **then**
7:         $P_{PI}^{RA}=0$ and $SoC=SoC'+\dfrac{C_e \Delta P}{B_c}$ (Decision A)
8:       **else**
9:         $P_{PI}^{RA}=\Delta P - \dfrac{B_c(Ma_s - SoC')}{100}$ and $SoC=SoC'+\dfrac{C_e(Ma_s-SoC')}{100}$
          (Decision B)
10:      **end if**
11:    **else**
12:      **if** $SoC'+\dfrac{C_e M_c}{100} \leq Ma_s$ **then**
13:        $P_{PI}^{RA}=\Delta P - \dfrac{B_c M_c}{100}$ and $SoC=SoC'+\dfrac{C_e M_c}{100}$ (Decision C)
14:      **else**
15:        $P_{PI}^{RA}=\Delta P - \dfrac{B_c(Ma_s - SoC')}{100}$ and $SoC=SoC'+\dfrac{C_e(Ma_s-SoC')}{100}$
          (Decision B)
16:      **end if**
17:    **end if**
18: **else**
19:    $\Delta P = L - P_{PV}$ and $P_{PI}^{RA}=0$
20:    **if** $\dfrac{B_c M_d}{100} \geq \Delta P$ **then**
21:      **if** $SoC'-\dfrac{\Delta P \cdot 100^2}{B_c D_e} \geq Mi_s$ **then**
22:        $P_{PC}^{AR}=0$, $S_c=L$, and $SoC=SoC'-\dfrac{\Delta P \cdot 100^2}{B_c D_e}$ (Decision D)
23:      **else**
24:        **if** $SoC' \geq Mi_s$ **then**
25:          $P_{PC}^{AR}=\Delta P - \dfrac{B_c(SoC'-Mi_s)D_e}{100^2}$, $S_c=P_{PV}+\dfrac{B_c(SoC'-Mi_s)D_e}{100^2}$, and
          $SoC=Mi_s$ (Decision E)
26:        **else**
27:          $P_{PC}^{AR}=\Delta P$, $S_c=P_{PV}$, $SoC=SoC'$, and $SoC'-\dfrac{B_c M_d}{100} \geq Mi_s$
          (Decision F)
28:        **end if**
29:      **end if**
30:    **else**
31:      **if** $SoC'-\dfrac{B_c M_d}{100} \geq Mi_s$ **then**
32:        $P_{PC}^{AR}=\Delta P - \dfrac{B_c M_d D_e}{100^2}$, $S_c=P_{PV}+\dfrac{B_c M_d D_e}{100^2}$, and $SoC=SoC'-\dfrac{B_c M_d}{100}$
          (Decision G)
33:      **else**
34:        **if** $SoC > Mi_s$ **then**
35:          $P_{PC}^{AR}=\Delta P - \dfrac{B_c(SoC'-Mi_s)D_e}{100^2}$, $S_c=P_{PV}+\dfrac{B_c(SoC'-Mi_s)D_e}{100^2}$, and
          $SoC=Mi_s$ (Decision E)
36:        **else**
37:          $P_{PC}^{AR}=\Delta P$, $S_c=P_{PV}$, $SoC=SoC'$, and $SoC'-\dfrac{B_c M_d}{100} \geq Mi_s$
          (Decision F)
38:        **end if**
39:      **end if**
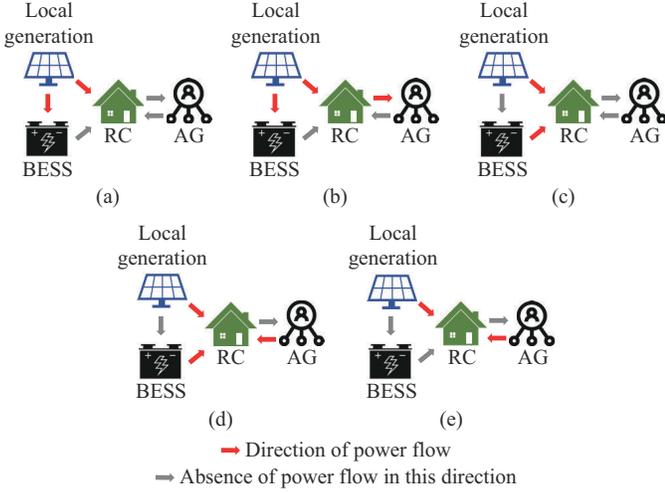40:   **end if**
41: **end if**
42: **end for**

Fig. 3. HEMS decision options for prosumers with BESS. (a) Decisions A and C. (b) Decision B. (c) Decision D. (d) Decisions E and G. (e) Decision F.

To determine the prices of consumed energy (W_{EC}^{PR}) and injected energy (W_{EI}^{RP}) into the P2P market, as well as the prices of consumed energy (W_{EC}^{UR}) and injected energy (W_{EI}^{RU}) into the UG, two scenarios are established based on P2P market availability, as shown in Table IV. If the P2P market is unavailable, electricity prices are determined by the local UG [27]. However, if the P2P market is available, electricity prices are set by the AG.

TABLE IV
UNIT ELECTRICITY PRICE FOR RCs [27]

Status of P2P market	Parameter	Price (USD/kWh)
Unavailable	Imported energy from UG	0.19
	Injected energy into UG	0.11
Available	Imported energy from AG	0.18
	Injected energy into AG	0.14

Figure 4 illustrates the total energy costs of community as a function of PV penetration in a local microgrid.
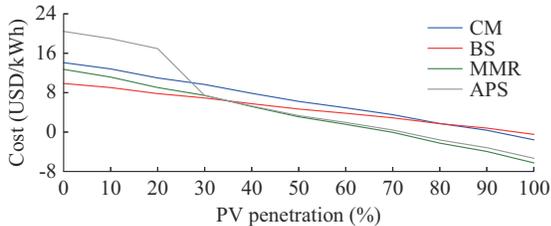
Fig. 4. Total energy costs of community v.s. PV penetration in a local microgrid.

Four different market price methods are analyzed using electricity market price data from [10], i.e., conventional method (CM), bill sharing (BS), mid-market rate (MMR), and auction-based pricing strategy (APS). For a 50% PV penetration in a microgrid, the MMR shows lower energy costs for RCs. According to price data from an MMR market, fixed imported and injected energy prices into the P2P

market are assumed to be 93% and 134% of the UG imported and injected prices, respectively. Therefore, the P2P market enables RCs to engage in energy trading by purchasing energy at a lower cost from other prosumers or selling PV surpluses at a higher price compared with transactions with the UG.

C. AG Trading Contracts

AGs act as intermediaries between RCs and the UG, generating profits through the coordination of energy transactions in the P2P market. This involves purchasing energy from prosumers at a lower cost than the selling price to RCs in the P2P market, while also receiving incentives from the UG for frequency response (FR) participation.

Algorithm 3 summarises the management of power flows among the AG, the UG, and RCs. The outputs consist of $C_T^R(i_R)$ for each RC, the power injected from AG to UG P_{PI}^{AU}, and the power consumed by AG from UG P_{PC}^{UA}. At each time step t, three possible decisions are considered depending on the presence of power surplus and power deficits within the P2P market, as shown Fig. 5.

Algorithm 3: management of power flows among AG, UG, and RCs

Input: Δt, $P_{PC}^{AR}(i_R)$, $P_{PI}^{RA}(i_R)$, W_{EC}^{PR}, W_{EI}^{RP}, W_{EC}^{UR}, and W_{EI}^{RU}

Output: $C_T^R(i_R)$, P_{PI}^{AU}, and P_{PC}^{UA}

1: **for** $t = 0$ to T **do**
2:    **if** $\sum P_{PI}^{RA}(i_R) > 0$ and $\sum P_{PC}^{AR}(i_R) > 0$ **then**
3:      P2P market is available
4:      **if** $\sum P_{PI}^{RA}(i_R) \geq \sum P_{PC}^{AR}(i_R)$ **then**
5:        $r_C = 1$ and $r_I = \sum P_{PC}^{AR}(i_R)/\sum P_{PI}^{RA}(i_R)$
6:      **else**
7:        $r_C = \sum P_{PI}^{RA}(i_R)/\sum P_{PC}^{AR}(i_R)$ and $r_I = 1$
8:      **end if**
9:    **else**
10:      P2P market is unavailable
11:      $r_C = 0$ and $r_I = 0$
12:    **end if**
13:    **for** i_R in RCs **do**
14:      $C_{EI}^{RA}(i_R) = P_{PI}^{RA}(i_R)[r_I W_{EI}^{RP} + (1-r_I)W_{EI}^{RU}]\Delta t$
15:      $C_{EC}^{AR}(i_R) = P_{PC}^{AR}(i_R)[r_C W_{EC}^{PR} + (1-r_C)W_{EC}^{UR}]\Delta t$
16:      $C_T^R(i_R) = C_{EC}^{AR}(i_R) - C_{EI}^{RA}(i_R)$
17:    **end for**
18:    $P_{PI}^{AU} = (1-r_I)\sum P_{PI}^{RA}(i_R)$
19:    $P_{PC}^{UA} = (1-r_C)\sum P_{PC}^{AR}(i_R)$
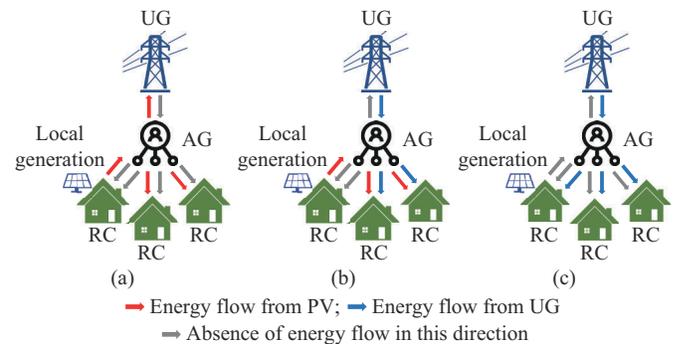20: **end for**

Fig. 5. Schematic diagram of possible AG decisions for energy transactions. (a) Decision A. (b) Decision B. (c) Decision C.

The total cost of energy consumed by RC from AG is determined as:

$$TC_{EC}^{AC}(t) = \sum_{i_R=1}^{n} C_{EC}^{AR}(i_R, t) \tag{10}$$

where n is the number of RCs. Likewise, the total cost of energy injected from the RC to AG is determined as:

$$TC_{EI}^{CA}(t) = \sum_{i_R=1}^{n} C_{EI}^{RA}(i_R, t) \tag{11}$$

Also, the cost of energy injected from AG to UG is determined as:

$$C_{EI}^{AU}(t) = \int_{t_s}^{t_e} P_{PI}^{AU}(t) W_{EI}^{RU} dt \tag{12}$$

Similarly, the cost of energy consumed and paid by the AG is determined as:

$$C_{EC}^{UA}(t) = \int_{t_s}^{t_e} P_{PC}^{UA}(t) W_{EC}^{UR} dt \tag{13}$$

Additionally, an economic incentive from the UG to the AG is proposed, involving the receipt or injection of energy during critical periods when FR is needed. The proposed incentive costs, as detailed in Table V, are assumed to be 10% of the energy costs set by the UG.

TABLE V
INCENTIVE COSTS FROM UG TO AG FOR FR

Parameter	Symbol	Cost (USD/kWh)
Incentive by receipt of energy	W_{FRR}^{UA}	0.02
Incentive by injection of energy	W_{FRI}^{AU}	0.01

During periods when the current load of the UG is lower than the average load of the past week, an increase in demand is required to stabilize the grid frequency. Consequently, the UG rewards AGs that consume power during this period, which is determined as:

$$C_{FR}^{UA}(t) = \int_{t_s}^{t_e} P_{PC}^{UA}(t) W_{FRR}^{UA} dt \tag{14}$$

Similarly, when the current load exceeds the average load of the past week, surplus power injections into the UG become necessary. Consequently, the UG will provide rewards to AGs that inject power during this period, determined as:

$$C_{FR}^{AU}(t) = \int_{t_s}^{t_e} P_{PI}^{AU}(t) W_{FRI}^{AU} dt \tag{15}$$

Finally, the total income of AG is determined as:

$$TI_{AG}(t) = TC_{EC}^{AC}(t) + C_{EI}^{AU}(t) + C_{FR}^{UA}(t) + C_{FR}^{AU}(t) - TC_{EI}^{CA}(t) - C_{EC}^{UA}(t) \tag{16}$$

D. UG Trading Contract

The total income of UG is determined as:

$$TI_{UG}(t) = C_{EC}^{UA}(t) - C_{EI}^{AU}(t) - C_{FR}^{UA}(t) - C_{FR}^{AU}(t) \tag{17}$$

III. RESULTS AND DISCUSSION

A numerical simulation is conducted to analyze the out-comes of the P2P market operation in a community microgrid, utilizing a 1-hour resolution. The simulations are conducted in Jupyter Notebook with Python 3.10.4, running on macOS Monterey V12.4. The hardware setup includes an Apple M1 chip, 8 GB of RAM, an 8-core CPU, and 7-core and 8-core GPUs. The scenario under examination represents a community consisting of two prosumers, two consumers, and one AG responsible for coordinating the P2P market and the UG. Meteorological data for a typical meteorological year (TMY) at an hourly resolution are sourced from the Explorador Solar platform [24], specific to a community located in Viña del Mar, Chile, with 33.03°S and 71.32°W. This database encompasses data recorded between 2004 and 2016 in Chile [28]. Furthermore, load profiles are obtained from open-access databases, derived from Energyplus, and featured hourly resolution based on a TMY [29]. These profiles encompass consumption related to lighting, household appliances, and miscellaneous devices, with no significant seasonal variations. The proposed configuration for RCs, including prosumer 1 (P1), prosumer 2 (P2), consumer 1 (C1), and consumer 2 (C2), is shown in Table VI.

TABLE VI
PROPOSED CONFIGURATION FOR RCS

RC	Installed PV power (kWp)	BESS capacity (kWh)	Annual demand (kWh/year)
P1	4.92	10.56	3722
P2	4.10	0	3022
C1	0	0	3722
C2	0	0	3022

A. Analysis for P2P Market Scenario

Sample results are generated for analysis during the period from April 1 to 2 in the first year of operation. Figures 6-8 display the results for P1. Figure 6 illustrates the profiles of PV generation and electrical load for P1. Local generation would experience significant fluctuations, largely influenced by meteorological conditions. Figure 7 shows that during high PV generation hours, the BESS would reach its maximum SoC. During nighttime period, it would be discharged to supply the local load. Figure 8 provides insight into the energy transfer dynamics. On April 1, a portion of PV surpluses would be injected into the AG for trading in the P2P market, while the remainder would be injected into the UG. On April 2, PV surpluses would be utilized for recharging the BESS. Power imported from the UG would be null, primarily owing to the self-consumption facilitated by the BESS.
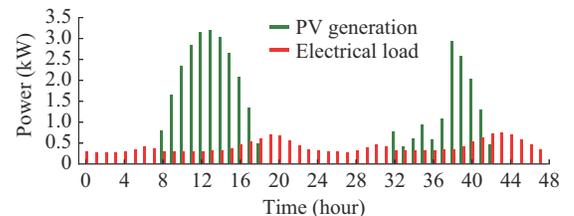

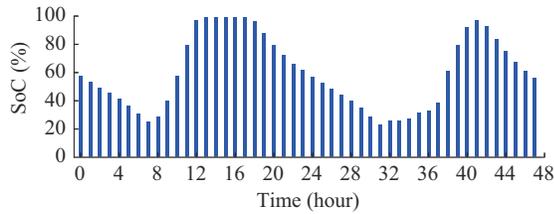Fig. 6.   Profiles of PV generation and electrical load for P1.
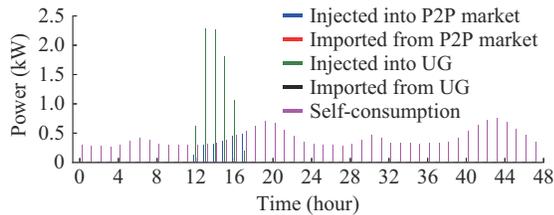
Fig. 7.   SoC profile for P1.

Fig. 8.   Profiles of self-consumption and power fluxes for P1 including P2P market and UG.

Figures 9 and 10 display the results for P2. Figure 9 shows the profiles of PV generation and electrical load for P2. Figure 10 reveals a increase in power injections into both the P2P market and the UG compared with P1, due to the lower load and the absence of a BESS. The self-consumption would exclusively take place during daylight hours, whereas during the nighttime period, there would be power imported from the UG.
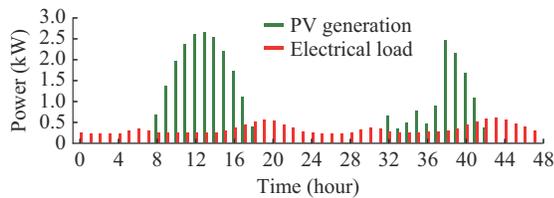
Fig. 9.   Profiles of PV generation and electrical load for P2.
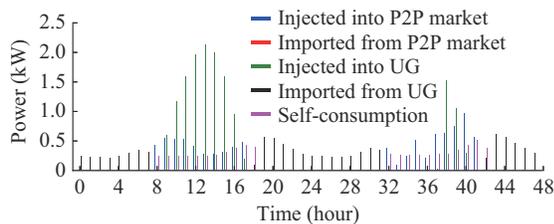

Fig. 10.   Profiles of self-consumption and power fluxes for P2 including P2P market and UG.

Figure 11 shows the power import profiles from both the P2P market and the UG for C1. Typically, power would be obtained from the P2P market during sunny hours, whereas nighttime would tend to rely on power supply of UG. In certain situations such as at hour 8, when there are insufficient offers in the P2P market, a portion of the load would be satisfied by the UG. A similar analysis can be applied to C2.

Figure 12 illustrates the net flows for RCs. P1 could generate profits on both days through a combination of self-consumption and power injections into both the P2P market and UG.
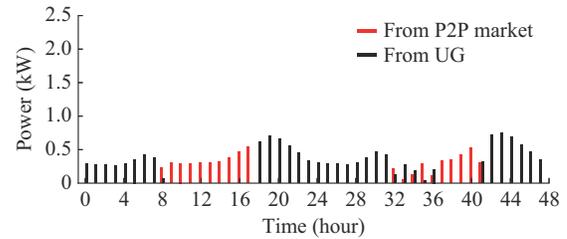

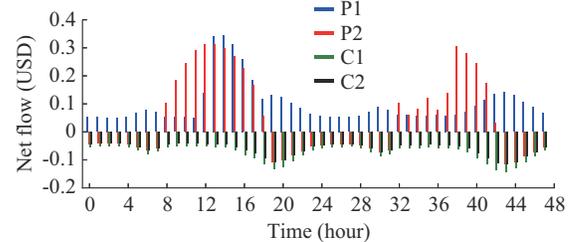Fig. 11.   Power import profiles from P2P market and UG for C1.

Fig. 12.   Net flows for RCs.

P2 also could achieve profits by means of self-consumption and by injecting surplus power into the AG during sunny hours. Both consumers would incur expenses for the energy they consume throughout the day.

Figure 13 shows the power flows in the P2P market and between the RC and the UG. The power flows managed in the P2P market would remain relatively low, peaking at 1 kW, in contrast to the higher power flows managed with the UG, which could reach up to 4.5 kW. However, the increased community consumption during periods of surplus injection into the UG would likely boost power transactions in the P2P market.

Figure 14 shows energy transaction costs and FR incentives for the AG. During nighttime periods, FR incentives would be common due to power imports from the UG, contributing to grid frequency stabilization. Payments to the AG for energy sales in the P2P market are shown, as well as payments to the community for acquiring PV surpluses, which would be subsequently resold in the P2P market. Transactions between the community and UG would be excluded as they have no impact on net flow of the AG. Figure 15 illustrates that the AG would earn a modest profit from both P2P transaction coordination and FR incentives. Nevertheless, the potential for greater revenue would exist by incorporating additional RCs and facilitating a higher amount of P2P market transactions.
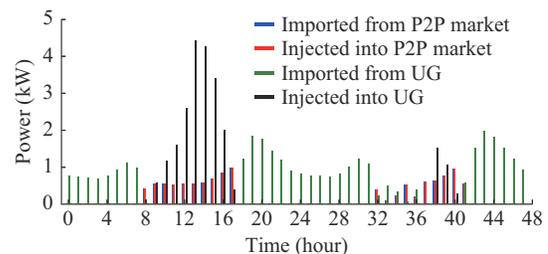

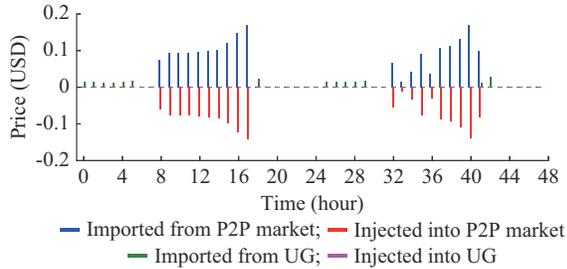Fig. 13.   Power plows in P2P market and between RC and UG.

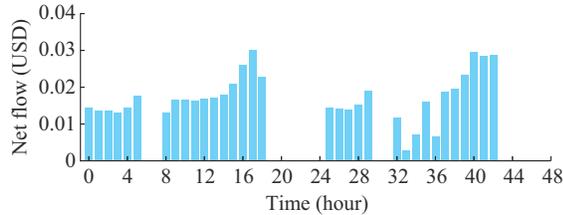Fig. 14.   Energy transaction costs and FR incentives for AG.

Fig. 15.   Net flow for AG.

B. Comparison Scenarios with and Without P2P Market

Table VII summarizes the daily electricity bills for RCs, as well as the daily incomes for the AG and the UG, based on P2P market availability. For P1, the maximum daily electricity bill would remain unaffected, with only a minor impact on the average daily electricity bill. This is primarily due to limited engagement in the P2P market since a significant portion of surplus PV power is stored in the BESS. Benefits would be derived primarily when the BESS reaches full capacity, enabling the injection of surplus PV power into the AG. However, such occurrences would be infrequent, typically confined to the summer months. Consequently, the minimum electricity bills, representing the maximum daily income, would experience a reduction. P2 would obtain more significant benefits from the P2P market, leading to reductions in both the minimum and average daily electricity bills. P2 would actively participate in the P2P market, taking advantage of the prioritized allocation of PV surplus for trading. The maximum electricity bills would remain unaffected as it typically occurs on days with limited solar irradiation, preventing the generation of PV surplus for injection. Consumers would obtain reductions in their minimum and average daily electricity bills, owing to their opportunity to buy energy at a lower cost in the P2P market. However, the maximum electricity bills would be unaffected, as they would tend to occur when the P2P market is closed, unlike the minimum electricity bills, which would be prevalent during the summer months when surplus energy trading is more extensive. In scenarios where there is neither a P2P market nor participation in FR, the AG would not generate any income. In contrast, in scenarios involving FR and a P2P market, the AG would achieve an average daily income of 0.27 USD. Also, the average daily income for the UG would decrease due to reduced energy sales to the community with the P2P market implementation. However, potential cost savings from avoiding infrastructure damage through FR should be considered, although the accurate estimation would require

real data from the UG. The financial results for P2P market participants will also depend on the number of RCs to be considered and PV penetration in the microgrid.

TABLE VII
DAILY ELECTRICITY BILLS FOR RCS AND DAILY INCOMES FOR AG AND UG

Scenario	Net flow	Daily electricity bill and income (USD)					
		P1	P2	C1	C2	AG	UG
Without P2P market	The maximum	1.86	1.51	2.25	1.83	0	7.79
	The minimum	−3.15	−1.85	1.66	1.35	0	0.51
	Average	−1.67	−0.80	1.92	1.56	0	3.14
With P2P market	The maximum	1.86	1.51	2.25	1.83	0.43	7.69
	The minimum	−3.18	−1.96	1.62	1.31	0.08	−0.05
	Average	−1.68	−0.90	1.89	1.53	0.27	2.63

Table VIII presents an annual electricity bill estimate for each RC in three distinct scenarios: ① without PV and P2P market, ② with PV and without P2P market, and ③ with PV and P2P market. In the first scenario, all RCs are categorized as consumers. In the second scenario, prosumers can fully offset their annual electricity bills through PV systems. As per local regulations, they are eligible for reimbursement from the UG at the end of the year for the surplus injections that exceed their annual electricity bills. In the third scenario, where a P2P market is introduced, P1 and P2 could potentially enhance their profits, resulting in increased reimbursements of 13 USD and 49 USD, respectively. Conversely, C1 and C2 could witness marginal reductions in their annual electricity bills, approximately 1.71% and 1.75%, respectively, by participating in the P2P market. However, the increased participation of prosumers in the community would likely lead to a greater supply of power available in the P2P market, thereby enabling more significant reductions in electricity bills for consumers.

TABLE VIII
AVERAGE ANNUAL ELECTRICITY BILLS FOR RCS

Scenario	Annual electricity bill (USD)			
	P1	P2	C1	C2
Without PV and P2P market	701	569	701	569
With PV and without P2P market	−2	−33	701	569
With PV and P2P market	−15	−82	689	559

A profitability analysis of DER projects for prosumers has been conducted. The initial investment for P1 is 13333 USD plus the replacement of the BESS after 12 years for 9178 USD, whereas the initial investment for P2 is 3663 USD. Table IX provides insights into the net present value (NPV), IRR, and payback period, all projected over a 25-year horizon with a discount rate of 10%. These calculations assume fixed P2P market and UG electricity prices over the years. P1 would exhibit the minimum variations in results when the P2P market implementation is considered, mainly because of the limited involvement. In contrast, P2, with more active participation, would experience a 1.2% increase in IRR and a 0.4-year reduction in payback period.

TABLE IX
FINANCIAL COMPARISON FOR PROSUMERS

Prosumer	Without P2P market			With P2P market		
	NPV (USD)	IRR (%)	Payback period (year)	NPV (USD)	IRR (%)	Payback period (year)
P1	−6800	2.3	18.7	−6790	2.3	18.7
P2	1922	16.6	5.8	2276	17.8	5.4

Fig. 17. Sensitivity analysis of annual income for P2.

C. Sensitivity Analysis

A sensitivity analysis is conducted to assess the annual income variations for RCs, the AG, and the UG, in addition to evaluating the IRRs for DER projects. It involves varying the installed PV power capacities for P1 (ranging from 1.64 kWp to 8.20 kWp) and P2 (ranging from 0.82 kWp to 7.38 kWp), as well as adjusting the BESS capacity for P1 (ranging from 6.34 kWh to 14.78 kWh).

Figure 16 shows that annual income of P1 would rise with an increase in its installed PV power. This occurs because a greater amount of PV surplus would be generated for selling. Additionally, having a larger BESS capacity would result in a higher self-consumption rate; however, it also would lead to increased standby losses. Consequently, another criterion arises to determine the optimal BESS capacity, where the highest annual income of 10.56 kWh would be achieved. Conversely, P1 could attain a higher annual income if the installed PV power of P2 is reduced. This dynamic arises from competitive interactions in the P2P market. When P2 injects fewer surplus amounts, P1 could sell a larger surplus volume in the P2P market, thus enhancing the profits. With a PV installation of 3.3 kWp, the annual electricity bill for P1 would be fully covered.

Fig. 18. Sensitivity analysis of annual income for C1.

For the same reason, it is observed that with a lower BESS capacity of P1, a greater benefit would be generated for C1. The same trend applies to C2.

Figure 19 shows that as the installed PV power of P2 increases and the BESS capacity of P1 decreases, the annual income for AG would rise, due to the generation of larger PV surpluses, leading to increased energy transactions in the P2P market. However, an optimal point emerges based on the installed PV power of P1, with 3.3 kWp resulting in the highest annual income. This would occur because, when P1 installs less PV power, it would generate a higher demand in the P2P market, leading to a greater number of transactions that benefit the AG.
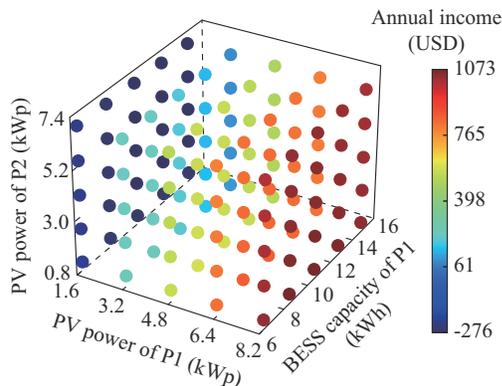

Fig. 16. Sensitivity analysis of annual income for P1.

Figure 17 shows that the annual income of P2 would increase significantly as its installed PV power increases, mirroring the trend observed in the case of P1. The annual income would exhibit insensitivity to the installed PV power and BESS capacity of P1. Similar to P1, an installed capacity of 2.5 kWp would fully offset the annual electricity bill.

Figure 18 shows that as the installed PV power of prosumers increases, the reduction in electricity bills for C1 would be higher. This is attributed to a greater availability of PV surpluses to be bought in the P2P market.
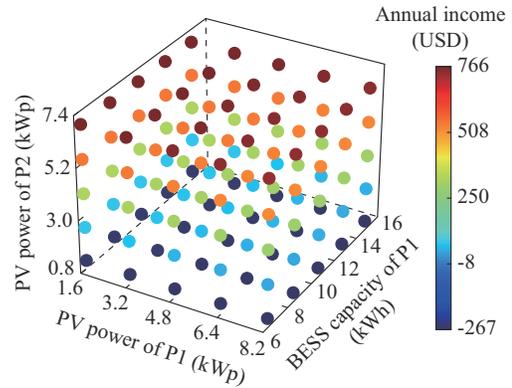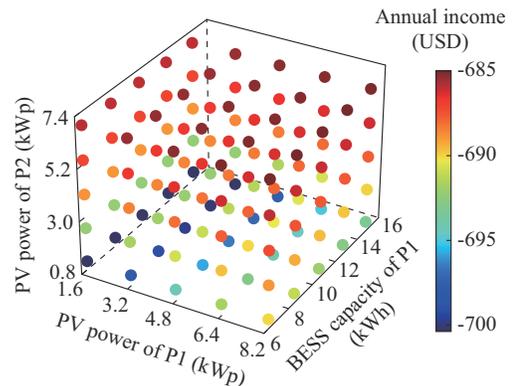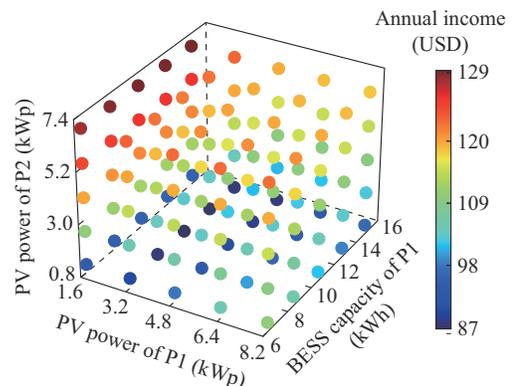

Fig. 19. Sensitivity analysis of annual income for AG.

Figure 20 shows that P1 would achieve a more favorable IRR as its installed PV power increases, due to increased surplus sales in the P2P market. Also, a reduction in the BESS capacity for P1 would result in a higher IRR, due to the lower initial investment cost of the BESS. The installed PV power of P2 does not significantly impact the IRR for P1. Figure 21 demonstrates that P2 would enhance its IRR when P1 decreases its installed PV power and augments its BESS capacity. This outcome is influenced by competitive dynamics in the P2P market. Moreover, P2 benefits from increasing its installed PV power up to an optimal point. The highest IRR could be achieved when P2 installs PV power of 2.5 kWp, primarily because a higher installed PV power entails a greater investment, and also due to the P2P market becoming saturated with surplus offers, which arises due to low demand.
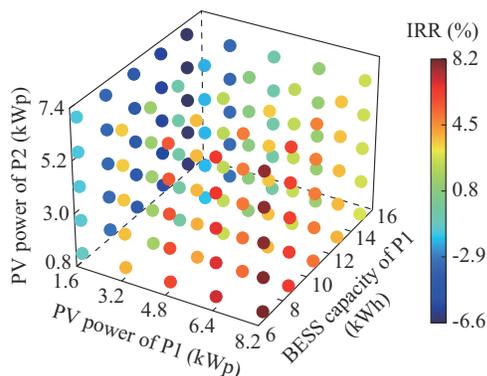

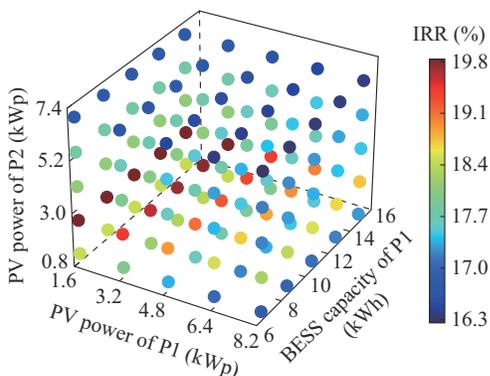Fig. 20. Sensitivity analysis of IRR for P1.

Fig. 21. Sensitivity analysis of IRR for P2.

D. Computational Time

Table X summarizes the computational time with different numbers of RCs, with 50% prosumers and 50% consumers. The time remains short for the number of RCs targeted by our work, increasing nearly linearly with lower numbers and exponentially for larger number of RCs. These time reflects complete simulations over a 25-year horizon of DG projects, including economic analyses, graph generation, profitability, and cash flow assessments.

E. Limitations and Implications

This subsection provides detailed information related to the limitations and the implications of the current work and the direction for further extension.

TABLE X
COMPUTATIONAL TIME WITH DIFFERENT NUMBERS OF RCS

Number of RCs	Computational time (s)
4	32
10	61
30	249
100	1998
400	7466

1) This paper focuses on a small number of participants (condominium of four households located in Viña del Mar, Chile). The small sample size and the specific location conditions may limit the generalization of the results to other case studies. However, further analysis is needed considering a larger number of participants with a greater variability in demand.

2) Chile exhibits diverse climatic conditions from its northern to southern zones. Although a significant aspect of this work involves investigating various simulation models for P2P markets in one region, the proposed models need to be extended and tested for other regions with different climate conditions and different service providers for better understanding on how different factors affect the results.

3) Despite the absence of an optimization model, the results obtained for the sensitivity analysis and scalability of PV penetration still reveal useful and intriguing patterns and trends on how the economic outcomes of participants vary according to different variables. Further extension is needed to employ optimization models to maximize economic outcomes for RCs.

4) The P2P model used in this paper is based on the current fixed pricing scheme in Chile, which may not accurately reflect the real-world dynamics. A comparison among different electricity pricing schemes needs to be considered, along with energy demand flexibility techniques such as smart appliances and thermal loads, as well as the inclusion of UG revenue due to FR.

5) The results of P2P market serve as a valuable starting point for more sophisticated local research endeavors. These endeavors could focus on refining, optimizing, and gradually adapting this technology in the current Chilean context, which boasts a unique solar resource. Unfortunately, this resource remains underutilized due to a lack of incentives for research and policy implementation, a challenge shared by countries facing similar contexts.

IV. CONCLUSION

This paper presents a sensitivity analysis for a local PV energy trading in a community microgrid to highlight the potential positive impacts and support the development of new regulations for Chile, which may facilitate the market penetration of DG based on PV systems. The proposed architecture has been evaluated for a small microgrid that consists of two prosumers, two consumers, one AG, and the UG, but the analysis and results may be extrapolated to a greater microgrid. The prosumers are engaged in DER projects, includ-

ing PV systems with or without BESS. A comprehensive daily and annual financial comparisons are conducted, comparing scenarios with and without a P2P market. Prosumers could experience an increase in their average daily income, while consumers could observe a reduction in their average daily electricity bills.

The results show that prosumer with PV system and BESS has a reduced benefit because most of its generated surpluses are stored, resulting in minimal participation in the P2P market. Conversely, prosumers with PV system and without BESS would prioritize selling surplus PV energy in the P2P market, leading to increased participation, showing a rise in IRR and a reduction in payback period. With local energy trading, the UG would decrease its purchase of surplus energy injected from the community. Thus, DER projects and P2P markets would offer a cost-effective alternative to address the urgent local need for increased storage capacity and tackle current operational challenges in the UG. Nonetheless, it would experience a decline in its daily income owing to reduced energy sales to the community, which has a systemic benefit by reducing electrical infrastructure damage; however, this economic saving needs to be adequately estimated.

A sensitivity analysis is conducted on the annual income of participants, as well as on the IRRs of DER projects. Prosumers could achieve higher annual income by installing higher PV capacities and optimizing BESS capacity. Regarding their IRRs, there seems to be a competitive dynamic in surplus sales in the P2P market among prosumers, where the PV capacity and storage capacity of one prosumer would interfere with the IRRs obtained by the other. For consumers, their benefits would increase as the supply of surpluses in the P2P market increases, namely when the installed PV capacity increases and the BESS capacity in prosumers decreases. The AG would also benefit by increasing the volume of energy transactions in the P2P market, with optimal points identified between surplus supply and energy demand. Future work aims to investigate individual return/revenue with a large number of participants in the local energy market. Furthermore, extend the proposed model to adapt different regions of Chile with different service providers.

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