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Analysis of the Implementation of Virtual Power Plants and Their Impacts on Electrical Systems

Matheus Sabino Viana *, Dorel Soares Ramos, Giovanni Manassero Junior and Miguel Edgar Morales Udaeta

Department of Electrical Energy and Automation Engineering, Polytechnic School, Universidade de São Paulo, Avenida Professor Luciano Gualberto, Travessa 3, No. 158, São Paulo 05508-010, SP, Brazil; dorelram@usp.br (D.S.R.); manassero@usp.br (G.M.J.); udaeta@pea.usp.br (M.E.M.U.)
* Correspondence: matheus.s.viana@usp.br or mviana.eng@gmail.com

Abstract: The increasing penetration of Distributed Energy Resources (DERs) in Distribution Systems (DSs) has motivated studies on Virtual Power Plants (VPPs). However, few studies have jointly assessed the sizing and economic attractiveness of VPPs from the entrepreneur's perspective and the potential benefits and impacts on power systems while maintaining the scope to DSs. This study proposes a methodology for sizing VPPs and simulating their economic optimal dispatch and economic attractiveness with a focus on the entrepreneur's viewpoint. In addition, it also evaluates VPPs' potential benefits and impacts on a DS or Transmission System (TS) while considering the interface between the Distribution System Operator (DSO) and the Transmission System Operator (TSO). The methodology employs optimization to minimize the Net Present Cost (NPC) of the project, in relation to sizing the DERs, and to obtain the economic optimal dispatch of the BESSs that comprise the VPP. Moreover, a power flow analysis and probabilistic reliability assessment are used to evaluate the benefits and impacts on the power system. The methodology was applied to a case study involving Photovoltaic (PV) systems and Battery Energy Storage Systems (BESSs) used by aggregated medium voltage consumers, which configure Technical Virtual Power Plants (TVPPs) participating in Demand Response (DR) via incentives, with a network model of the Brazilian National Interconnected System (SIN) adapted from the 2030 Ten-Year Energy Expansion Plan (PDE) of the Energy Research Office (EPE), along with data from the Geographic Database of the Distribution Utility (BDGD). The results indicate the economic attractiveness of DERs according to the premises adopted and indicate improvements in TS reliability indexes with the possibility of TVPPs' dispatch after transmission contingencies.

Keywords: virtual power plants (VPPs); distributed energy resources (DERs); photovoltaic distributed generations (PVDGs); battery energy storage systems (BESSs); probabilistic reliability assessment; TSO–DSO interface

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1. Introduction

1.1. Background

A Virtual Power Plant (VPP) can be defined as an aggregation of Distributed Energy Resources (DERs) capable of participating in electricity markets and providing services to the electrical system [1,2].

The economic dispatch imbued in the VPP concept implies having at least one type of dispatchable resource among the DERs.

Unlike microgrids, VPPs are not necessarily limited to a particular geographic area in which a set of DERs is located, but can combine resources from different areas, connected to different distribution substations and located in different municipalities [1,2].

DERs, when aggregated by VPPs, gain visibility into wholesale electricity markets, such as energy, capacity, and ancillary services, and can constitute resources for the planning and operation of Distribution Systems (DSs) and Transmission Systems (TSs) [1].

VPPs rely significantly on smart metering and information technology for their operations [1]. Information communication technologies can drive modern Demand-side-Management (DSM), including the VPP scheme managing and controlling DERs to maximize benefits to the Distribution System Operator (DSO) and the consumers [3].

In price-based Demand Response (DR), signaling to the consumer can be done, for example, through energy consumption or demand tariffs with value distinctions throughout the day, on different types of day (such as working days, Saturday, and Sunday), and throughout the year (such as the summer and winter seasons). Incentive-based DR refers to the possibility of receiving revenue by the consumer as a result of responding to demand control mechanisms by the DSO or Transmission System Operator (TSO) [4].

The focus of this work is a Technical Virtual Power Plant (TVPP), i.e., a type of aggregation in which there is a characterization of benefits for the electrical grid as a product, given the geographical arrangement of DERs, which results in local influences [5] that allow the TVPPs to constitute a planning and operational resource for the electrical system, and, thus, participate in electricity markets.

Possible services that a TVPPs can offer include (i) reducing demand, providing operational flexibility, and allowing postponing or avoiding investments in network expansions and reinforcements; (ii) network congestion management; (iii) ancillary services; and (iv) balancing the energy portfolio for Balancing Responsible Parties (BRPs).

1.2. Literature Review

Ref. [6] found that few works in the literature have sought to address the problem of the operational capacity of aggregated DERs aiming to participate in distributed energy marketplaces considering network constraints in the context of interactions between the TSO and DSO. The authors proposed a methodology for modeling and characterizing DERs flexibility that includes the Battery Energy Storage Systems (BESSs), identifying capacity, ramp, duration, and cost as key metrics, and incorporates an analysis using Optimal Power Flow (OPF) with a representation of active and reactive power, as applied to a conceptual test system. The authors present a potential use case in a distribution marketplace environment where aggregators exchange information with the DSO to plan their market participation.

Ref. [5] discussed the volatility and limited predictability of loads and the generation of DERs, which would make the capacity of the TVPP uncertain, and proposed the Robust Capability Curve (RCC) method to determine the curve capacity of the TVPP. This was associated with OPF based on a linearized network model and applied to a case study using the IEEE 13-bus model.

Ref. [7] indicated that, although VPPs can be a flexible source for the power system, their inclusion in planning has rarely been considered in academic works. They also stated the importance of establishing flexibility indexes for the system.

The results of the work in [8] highlighted the strong interaction between voltage support and reactive power in the local network and market participation at a systemic level to increase the versatility of the VPP in order to maximize its revenue. This is particularly relevant in the context of the operation of DSs and emerging markets for DERs, which are subject to local network restrictions. The interaction of DERs with the local network is of great interest to a VPP, as it constitutes a possible additional revenue stream, and a VPPs's ability to participate in multiple markets is considered.

Ref. [9] presented a generic optimization method to evaluate the suitability of power system generation, incorporating an aggregated probabilistic model representing several Active Distribution Networks (ADNs) in the form of a VPP and using a linearized network model. The authors evaluated reliability indexes such as Loss of Load Expectation (LOLE) and Loss of Load Frequency (LOLF) and proposed indexes to quantify different performance aspects of the VPP. The method was implemented on a DS test system with four buses and on the IEEE 69-bus model, using sequential Monte Carlo simulation techniques.

According to Ref. [10], a key concept and requirement for the operational and effective implementation of a large number of DERs, which includes power sources and DR to enable flexibility and services to the grid, is the aggregation of DERs. This aggregation function and the functions necessary to enable network services are provided by Distributed Energy Resource Management Systems (DERMSs). The mentioned report provides a guide for developing a functional specification for DERMSs and a description of the network services that aggregated DERs can provide to DSs and TSs, or at market levels. It also deals with implementation issues, interoperability requirements, and communication and information infrastructure. The approach is extended to VPP control systems.

According to [11], retailers can bring together dispersed consumers and generators, acting as a link between them and the wholesale market. The authors analyzed the economic foundations of aggregators, evaluating the factors that determine aggregators' roles in electrical systems in different technological and regulatory scenarios. Considering the regulatory and technological contexts, the authors identified three main value categories created by aggregators: fundamental aggregation, transient aggregation, and opportunistic aggregation.

Fundamental aggregation has systemic value, which is inherent to the aggregator's function, regardless of regulatory and technological particularities and the consumers' level of knowledge, and it tends to be permanent. Transient aggregation contributes to improving the performance of the electrical system. However, it tends to decline with technological, regulatory, or system management improvements. In turn, opportunistic aggregation has individual value for the aggregating agent and results from regulatory or market design failures. If strong economies of scale and scope are present, a centralized aggregator, such as the system operator, could be the most efficient industry structure [11].

In Brazil, the social participation process TS nº 011/2021 of the National Electric Energy Agency (ANEEL) [12] aimed to obtain subsidies for the elaboration of regulatory model proposals for the insertion of DERs, including DR, VPPs, and microgrids, based on the investigation of regulatory models that could be applied in the Brazilian electrical sector. Such models should be based on best international practices and consider the potential impacts on the electricity sector [2,12].

The Energy Research Office (EPE) in Brazil has conducted studies on the economic attractiveness of Behind-the-Meter (BTM) batteries for the Ten-Year Energy Expansion Plan (PDE) 2032 [13]. However, only captive consumers not participating in the free contracting environment (ACL) have been considered, and a scheme with both Photovoltaic (PV) systems and BESS BTM for MV consumers, as proposed in this work, has not been evaluated.

1.3. Research Gap and Motivation

To the best of the authors' knowledge, the methodologies proposed in the literature related to power systems do not include a joint assessment of the economic attractiveness of investment in DERs, sizing, and the optimal economic dispatch of TVPPs, and an assessment of the technical impacts on a DS and TS, as proposed in this work. The specific contributions of this paper are outlined in more detail in Section 1.4.

Previous works [14–16] inspired the present study, which proposes a methodology for TVPPs sizing and simulating their optimal economic dispatch and economic attractiveness, with a focus on the entrepreneur's point of view. In addition, we propose a system to evaluate the potential benefits and impacts of a TVPP on a DS, TS, or both, considering the interface between the DSO and TSO. The system also considers possible synergies that allow the DSO to capture benefits for the power system in its relationship with the TVPPs, which can be offered to the TSO in the form of network services, for example, through DR via incentives for the consumers participating in TVPP.

1.4. Contribution

The contributions of this work are as follows:

- We propose a methodology for TVPP sizing and simulating their optimal economic dispatch and economic attractiveness, with a focus on the entrepreneur's point of view, in addition to evaluating potential benefits and impacts of the TVPP on the DS or TS;

- The methodology can help entrepreneurs to establish sustainable business cases as aggregators, involving the deployment or operation of aggregated DERs in the form of a TVPP, which exchanges information with the DSO or TSO and can receive directions from the operator in order to participate in electricity markets;
- In case of the deployment of DERs by the consumers themselves, the methodology can help a centralized aggregator such as the DSO to evaluate potential benefits and impacts of coordinating the aggregated DERs on the DS or TS;
- Our proposal for DERs sizing and simulating the optimal economic dispatch of TVPPs complements other works, which focused on the functional specification of DERMSs, including requirements for interoperability and the communication infrastructure;
- The proposed methodology allows for quantifying potential synergies between DERs, the DSO, and TSO, allowing for the evaluation of the VPP business model as an opportunity for aggregation with systemic value.

The proposed methodology was applied to a case study based on computational simulations, with DERs composed of PV systems and BESSs installed in Medium Voltage (MV) consumers aggregated as a TVPP participating in DR via incentives, with a Brazilian National Interconnected System (SIN) network model adapted from the PDE 2030 from the EPE and the use of data from the Geographic Database of the Distribution Utility (BDGD).

The case study was carried out with TVPPs located in a real location, considering local data from the solar source, tariffs, and load curves. The probabilistic reliability assessment of the TS allowed for the comparison of TVPP alternatives through reliability indexes, which could be calculated in a systemic or stratified manner.

The results indicate the economic attractiveness of DERs according to the premises adopted and demonstrated improvements in TS reliability indexes with the possibility of TVPPs dispatch after transmission contingencies.

1.5. Paper Organization

The remainder of this work is organized as follows. Section 2 presents the materials and methods. Section 3 presents the results. Moreover, Section 4 presents the conclusions.

2. Materials and Methods

2.1. Methodology

Figure 1 illustrates the methodological steps and the simulation tools.

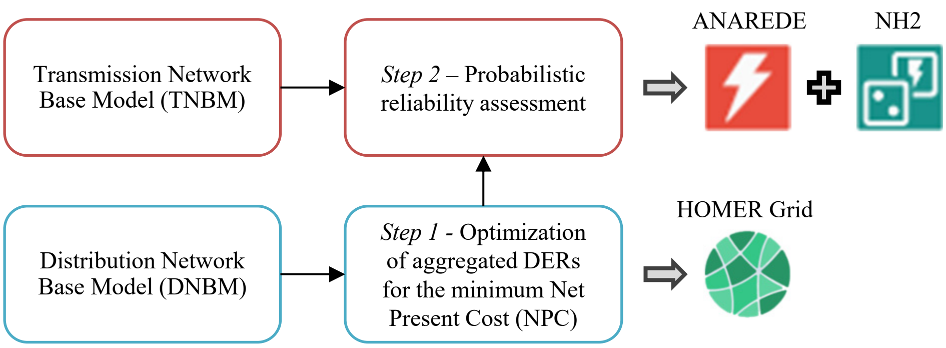


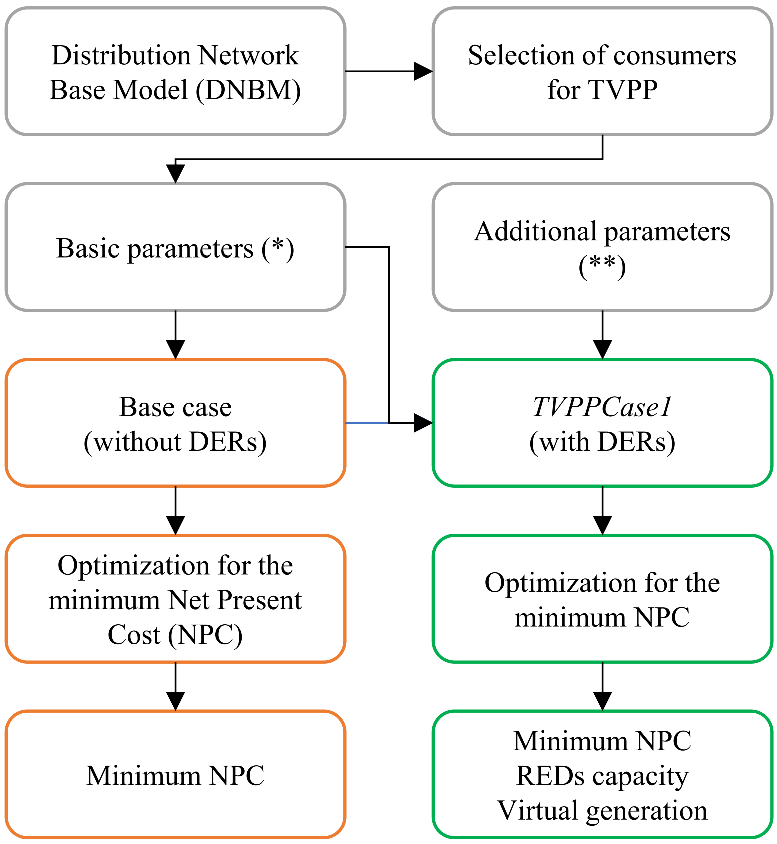
Figure 1. Methodological steps and simulation tools.

HOMER Grid is an economic optimization and sizing simulation tool for DERs installed BTM which was developed by HOMER Energy (by UL) [17]. The present work proposes a new use of the HOMER Grid tool to simulate aggregated DERs as a TVPP.

Network Analysis Program (ANAREDE) [18] is a power flow simulation tool developed by the Electric Power Research Center (CEPEL). It was used in this work to prepare a converged Bulk-Power System (BPS) power flow case, which is imported as a reliability base case into the Composite Reliability Analysis and Operational Reserve Calculation Program (NH2) [19,20] simulation tool, also developed by the CEPEL, to carry out reliability simulations.

As a premise, the proposed methodology considers that the DS (Distribution Network Base Model (DNBM)) is modeled as a load with a radial configuration connection to the TS (Transmission Network Base Model (TNBM)).

Figure 2 details Step 1 of the methodology.



(*) Aggregated demand profile and contracted demand, tariff/energy price and project economic parameters.
(**) DERs technical and economic data and DR program data.

Figure 2. Step 1 of the methodology.

Step 1 of the methodology considers consumer data obtained from the DNBM and consists of the following:

- Sizing the DERs aggregated capacity ($AgCap_{DERs}$) and optimizing the project Net Present Cost (NPC) to the minimum NPC (NPC_{min});
- Obtaining the dispatchable DR potential of the TVPPs (virtual generation).

The NPC of a project or system is the present value of all the investment, installation, and operational costs minus the present value of all the revenues over the project's lifetime [21]. The DERs, which a TVPP comprises, are simulated in HOMER Grid in an aggregated form.

The HOMER Grid [21] optimization and sensitivity analysis algorithms facilitates the evaluation of possible DERs configurations in the face of (i) a high number of technological options; (ii) complexity of tariff structures; (iii) variations in costs; and (iv) the availability of energy resources.

The *HOMER Optimizer* is the proprietary derivative-free optimization algorithm used in the HOMER Grid, which seeks the minimum cost system [21]. Examples of decision variables in the optimization process are [21] (i) PV system capacity; (ii) number of batteries; (iii) converter size; (iv) BESS dispatch strategy; and (v) maximum demand from the grid.

In this work, we propose the sizing of the aggregate capacity of DERs through optimization for the minimum NPC of the project, based on input data and problem constraints, taking into account the DERs capacities and the dispatch curve of the dispatchable DER(s) as decision variables.

In Step 1, the optimization for NPC_{min} considers the basic and complementary parameters indicated in Figure 2, with $AgCap_{DERs}$ and the dispatch curve of the dispatchable DERs as decicion variables.

A base case (BaseCase) without DERs and a case $TVPPCase1$ with DERs were simulated, obtaining a virtual generation potential of the TVPPs.

In this work, for simplicity, we disregarded the possible increase in virtual generation due to the reduction in technical losses in the DS during DR events downstream of the TVPPs aggregation buses in the TNBM.

Optionally, to evaluate the technical impacts of the TVPP on the DS voltages and technical losses, power flow simulations may be conducted with the simulation tool Open Distribution System Simulator (OpenDSS) considering TVPP penetration [16].

Figure 3 details Step 2 of the methodology.

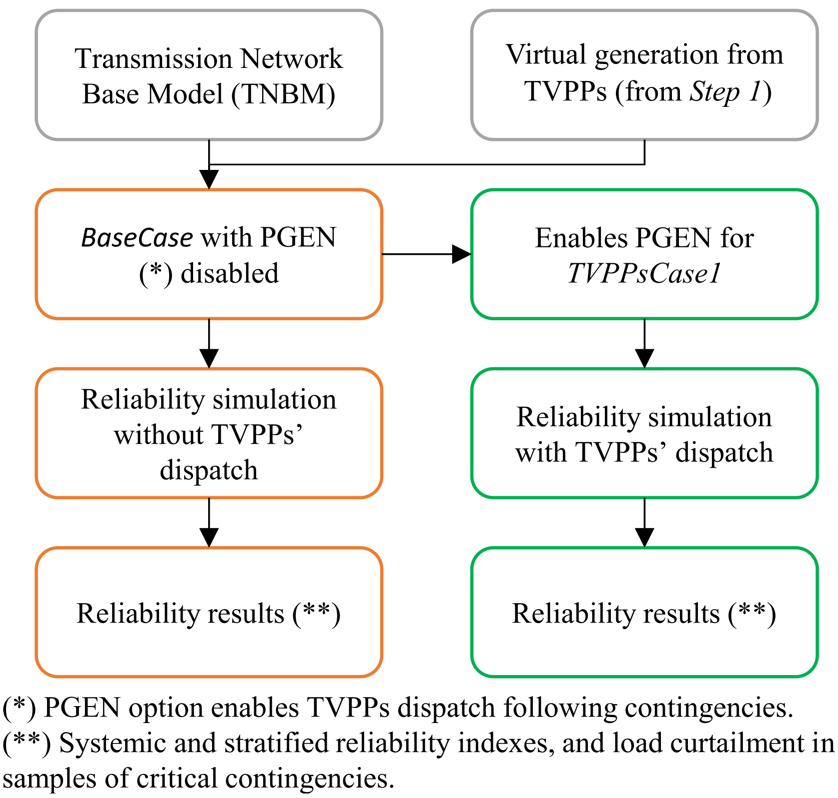


Figure 3. Step 2 of the methodology.

Step 2 of the methodology consists of the probabilistic reliability assessment [20] of the TS considering the possibility of dispatching active power from the TVPPs (virtual generations) as corrective measures following transmission contingencies by the OPF of the NH2 reliability model [19,20].

The ANAREDE power flow simulation tool is used to prepare a converged BPS power flow case from a given database, which is imported as a reliability base case into the NH2 reliability simulation tool.

The probabilistic reliability assessment with the NH2 simulation tool, based on the state enumeration method, makes use of the power flow to assess the adequacy of the system's contingency states at a given load scenario and the OPF for the application of corrective measures [19].

The active power dispatch of the TVPPs was considered among the corrective measures following transmission contingencies. In the base case (BaseCase), the dispatch of the TVPPs was not enabled (the active power redispatch (PGEN) function of the NH2's OPF was disabled). In the case of TVPPsCase1, the dispatch of the TVPPs was enabled (the PGEN function of the NH2's OPF was enabled). The reliability results of both cases were compared.

2.2. Case Study

The case study in Brazil considered three fictitious TVPPs, each located in a municipality in the region of a distribution utility in the state of São Paulo (SP).

The TVPPs were as follows:

- $TVPP_{MOG}$, located in the municipality of Mogi das Cruzes;
- $TVPP_{SJC}$, located in the municipality of São José dos Campos;
- $TVPP_{TAU}$, located in the municipality of Taubaté.

Each TVPP was composed of randomly selected MV consumers, with a level of participation adopted so that the sum of the maximum demands of consumers aggregated by the TVPP (ΣDem_{max}^{AgC}) corresponded to 30% of the sum of maximum demands of the MV consumers in each municipality.

This 30% level of TVPP penetration was estimated based on prospective test simulations using the IEEE 8500-node test feeder [22] and the OpenDSS simulation tool, which did not result in reverse flows in the distribution substation nor increased technical losses in the DS, as presented in [15].

Table 1 presents information about the TVPPs considered in the case study.

Table 1. Information about the TVPPs considered in the case study. Based on [23,24].

Name	Number of Aggregated Consumers	ΣDem_{max}^{AgC} (MW)	TNBM Aggregation Bus
$TVPP_{MOG}$	103	75.8	1066-MOGI—SP088
$TVPP_{SJC}$	130	87.4	1067-SJC—SP088
$TVPP_{TAU}$	87	59.5	1068-TAU-BE-SP138

The typical load curve of an MV consumer was obtained from the aggregated MV load curve of the distribution utility's 2019 periodic tariff revision, with monthly seasonality according to maximum monthly demand data obtained from the BDGD [23].

It was assumed that the consumers drawn for the TVPPs could enter the ACL to establish a Power Purchase Agreement (PPA). A flat energy consumption cost from the grid was considered equal to the average difference settlement price (PLD) for the period from January 2014 to April 2019, which was equal to R$ 326.25/MWh [25] with additional tax rates as estimated for the distribution system use tariff (TUSD) [15].

Additionally, the consumers drawn for the TVPPs were subjected to the Brazilian TUSD green tariff and the self-production of energy (APE) modality for the reference year 2021 [26].

The taxes to be added to the TUSD were estimated as follows: ICMS 18%, PIS 0.87%, and COFINS 3.96%. The contracted demand was considered equal to the maximum demand, 2021 national holidays were used, and the green tariff flag was adopted.

Figure 4 shows the DERs diagram per consumer participating in the TVPP.

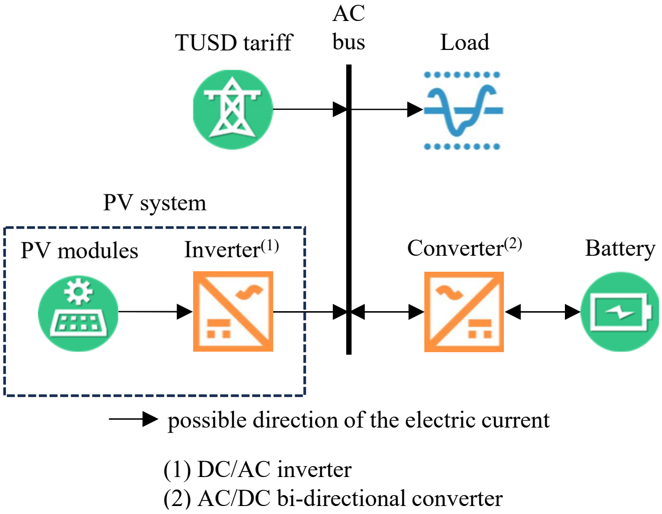


Figure 4. DER diagram per consumer participating in the TVPP.

The PV system comprised PV modules and the DC/AC inverter. The DC/AC inverter was implicitly modeled in the HOMER Grid [21].

The battery was connected to the AC bus through an AC/DC bi-directional converter for both rectification and inversion [27]. Battery charging was carried out via the PV system or the grid.

Table 2 presents typical PV system costs for capacity samples.

Table 2. Typical PV system costs for capacity samples. Based on [14,28].

Generic Flat Plate PV—Capacity (kW)	CAPEX (R$)	O&M (R$/Year)
4	19,520.00	97.60
50	194,500.00	972.50
1300	5,541,750.00	150,181.43
3900	16,324,500.00	391,788.00

The HOMER Grid simulation tool constructs a piecewise linear curve of CAPEX or the replacement cost from sample data of cost(s) per capacity of PV systems. The replacement cost is considered equal to CAPEX [21].

Table 3 presents typical BESSs costs.

Table 3. Typical BESS costs, based on [14,29–31].

Equipment	CAPEX (R$)	O&M (R$/Year)
116 kWh based on SAFT Intensium Max plus 20M ESSU Kinetic—quantity		
1	518,401.77	5813.25
4	1,700,000.00	8500.00
7	1,900,223.68	19,002.24
Converter—capacity (kW)		
100	156,502.27	2412.75
500	300,000.00	1500.00

For batteries, the capital or replacement cost curve was constructed by the HOMER Grid simulation tool from cost sample(s) for quantity(s) of a given type of battery with a specified energy storage capacity to make up a specific total energy storage capacity. The converter for a BESS can be modeled as a specific component, and its cost curve was constructed in an analogous way to that of PV systems [21].

The replacement cost of the batteries and converter were considered equal to the respective CAPEX.

The simulations in Step 1 were conducted with annual time series of the load curve, solar irradiance, and ambient temperature with a time step adapted to 15 min. Solar irradiance and ambient temperature data were obtained from the National Aeronautics and Space Administration (NASA) Prediction of Worldwide Energy Resource (POWER) database for coordinates −23.25, −45.75, in decimal degrees. The project's real discount rate was equal to 5.77% per year, and its useful life was 20 years [15].

The demand reduction incentive adopted was equal to R$ 1.96/kW, which was calculated based on the reference unit variable cost (CVU) of R$ 511.15/MWh in [25], adding the same tax rates adopted for the TUSD tariff, over a project lifetime of 20 years. The demand reduction bid corresponded to 75% of the MV consumers (aggregated) maximum demand.

A duration of 3 h per DR event was considered, with 48 events per year on random working days, starting between 10:01 and 18:00, and an hourly interval corresponding to the heavy load of the SIN in the period from November to March [15,32].

The demand reduction bid, obtained through the BESSs dispatch, the number of DR events per year, and the duration of the events were obtained using a heuristic method and test simulations in which it was verified that participation in DR resulted in a NPC_{min} lower than the NPC_{min} without participation in DR for the adopted incentive value.

The TNBM was prepared with the ANAREDE simulation tool based on the power flow database of the PDE 2030 of the EPE, for the year 2030, peak load level, and humid North Brazilian region as the generation scenario [24]. Single and double transmission contingencies were considered for the reliability assessment with the NH2 simulation tool, with typical data on failure rates and average repair times for lines and transformers obtained from reliability database (BDConf) (1999–2003) [33].

3. Results

3.1. Step 1

Figure 5 shows the NPC_{min} of the TVPPs.

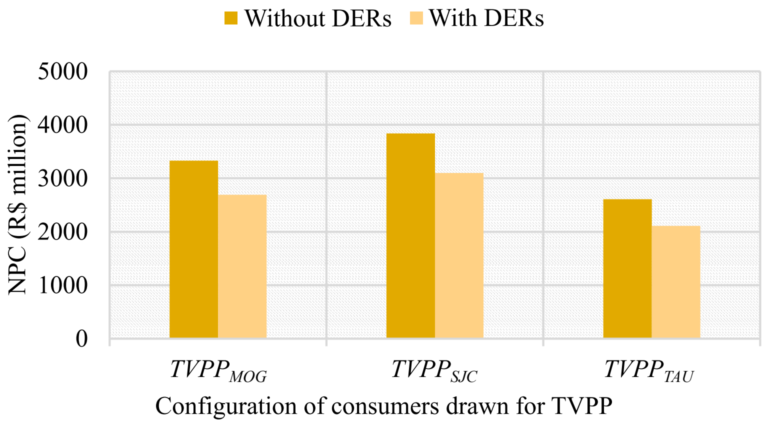


Figure 5. Minimum NPC.

For the TVPP configurations evaluated, the NPC_{min} with PV systems and BESSs was lower than without these DERs, demonstrating that the option of investing in DERs is economically advantageous. The reduction in NPC_{min} with DERs compared with the NPC_{min} without DERs was 19.2%, 19.3%, and 19.2%, respectively, for MV consumers selected for $TVPP_{MOG}$, $TVPP_{SJC}$, and $TVPP_{TAU}$. It is noteworthy that the configuration with PV systems and BESSs resulted in a lower NPC_{min} for all TVPPs when compared to a configuration with only PV systems.

Figure 6 shows the aggregated capacity of DERs of the TVPPs.

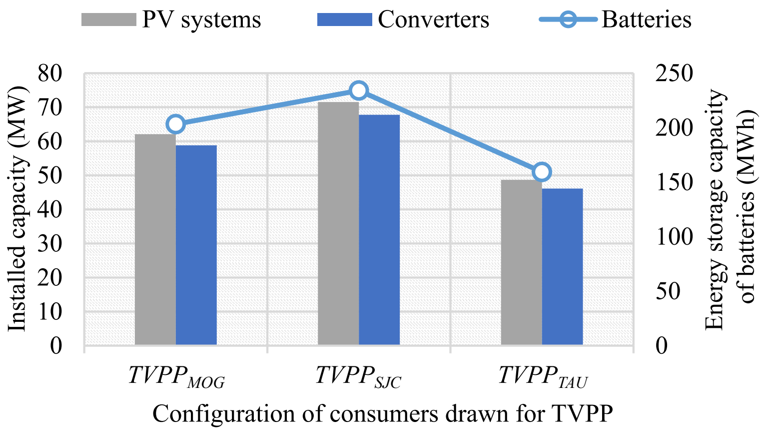


Figure 6. Aggregated capacity of DERs of the TVPPs.

Table 4 presents the virtual generation potential of the TVPPs.

Table 4. Virtual generation potential of the TVPPs.

TVPP	Virtual Generation Potential (MW)
$TVPP_{MOG}$	56.9
$TVPP_{SJC}$	65.5
$TVPP_{TAU}$	44.6
Total	167.0

3.2. Step 2

Table 5 presents the systemic reliability indexes.

Table 5. Systemic reliability indexes.

Index	Unity	BaseCase	TVPPsCase1	Variation
LOLP	%	4.73925×10^{-9}	4.73925×10^{-9}	0.00%
LOLE	h/year	4.15159×10^{-7}	4.15159×10^{-7}	0.00%
LOLF	occ./year	6.35042×10^{-8}	6.35042×10^{-8}	0.00%
LOLD	h	6.53750	6.53750	0.00%
EPNS	MW	7.56642×10^{-9}	6.20054×10^{-9}	−18.05%
EENS	MWh/year	6.62818×10^{-5}	5.43167×10^{-5}	−18.05%
SI	min	3.36206×10^{-8}	2.75515×10^{-8}	−18.05%

There was no variation in the Loss of Load Probability (LOLP), LOLE, LOLF, and Loss of Load Duration (LOLD) in TVPPsCase1 compared with BaseCase.

There was a 18.05% reduction in the Expected Power Not Supplied (EPNS), Expected Energy Not Supplied (EENS), and severity index (SI) in TVPPsCase1 compared with BaseCase.

Regarding the stratification of reliability indexes due to failure modes, there was a 38.47% reduction in the EENS of the overload failure mode, which varied from 3.10989×10^{-5} MWh/year in BaseCase to 1.91338×10^{-5} MWh/year in TVPPsCase1.

Table 6 presents the EENS by base voltage.

Table 6. EENS by base voltage.

Base Voltage (kV)	Unity	BaseCase	TVPPsCase1	Variation
138	MWh/year	1.44722×10^{-5}	1.14885×10^{-5}	−20.62%
88	MWh/year	5.18096×10^{-5}	4.28281×10^{-5}	−17.34%

Table 7 presents the SI by base voltage.

Table 7. SI by base voltage.

Base Voltage (kV)	Unity	BaseCase	TVPPsCase1	Variation
138	min	1.57030×10^{-8}	1.24656×10^{-8}	−20.62%
88	min	2.15907×10^{-7}	1.78478×10^{-7}	−17.34%

Regarding the stratification of reliability indexes by the base voltage, there was a reduction in the EENS and SI for the base voltages of 138 kV and 88 kV for TVPPsCase1 compared with BaseCase.

Table 8 presents the load curtailment for the contingency samples with the five most significant load curtailment reductions in TVPPsCase1 compared with BaseCase, which corresponds to double transmission contingencies.

Table 8. Load curtailment for the contingency samples with the five most significant load curtailment reductions.

Description	Unity	BaseCase	TVPPsCase1	Variation
S.JOSE-SP230 − S.JOSE-SP088(1) + S.JOSE-SP230 − S.JOSE-SP088(2)	MW	94.00	28.00	66.00
S.JOSE-SP230 − S.JOSE-SP088(1) + S.JOSE-SP230 − S.JOSE-SP088(3)	MW	94.00	28.00	66.00
S.JOSE-SP230 − S.JOSE-SP088(2) + S.JOSE-SP230 − S.JOSE-SP088(3)	MW	94.00	28.00	66.00
TAUBAT-SP138 − TAUBAT-SP440(1) + TAUBAT-SP138 − TAUBAT-SP440(3)	MW	224.00	179.00	45.00
TAUBAT-SP138 − TAUBAT-SP440(2) + TAUBAT-SP138 − TAUBAT-SP440(3)	MW	224.00	179.00	45.00

The most significant load curtailment reduction in TVPPsCase1 compared with BaseCase was 66.0 MW. The total redispatched power of the TVPPs ranged from 54.3% to 71.8% of the total virtual generation potential for the five contingencies presented in Table 8.

4. Conclusions

This work presents a methodology applied to a case study using the Brazilian SIN. It makes use of optimization for NPC_{min} for sizing DERs for sets of MV consumers that make up TVPPs participating in DR via incentives. In addition, it obtains the potential for the virtual generation of the TVPPs and uses a probabilistic reliability assessment to verify the potential benefits of these TVPPs as dispatchable resources following transmission contingencies for the reliability of the TS.

The benefits of the proposed work include (i) helping entrepreneurs to establish sustainable business cases as aggregators or helping the DSO as a centralized aggregator coordinating DERs developed by the consumers themselves to evaluate potential benefits and impacts on the DS or TS; (ii) our proposal for sizing DERs and simulating the optimal economic dispatch of TVPPs complements other works focused on the functional specification of DERMSs, including requirements for interoperability and the communication infrastructure; and (iii) the proposed methodology allows for quantifying potential synergies between DERs, the DSO, and TSO, allowing for the evaluation of the VPP business model as an opportunity for aggregation with systemic value.

A limitation of this work is the adoption of a typical peak load and generation scenario for the transmission system modeling (TNBM) due to the database and the reliability simulation tool considered in the case study. Future work should consider the stochastic analysis of demand and renewable-based generation scenarios for a more robust reliability analysis of the transmission system.

The configuration of DERs with PV systems and BESSs resulted in a lower NPC_{min} than the configurations with only PV systems or without DERs, demonstrating the economic attractiveness of TVPPs. The amount of reduction in dispatchable aggregated demand obtained with the TVPPs resulted in improvements in the reliability of the TS, which was verified through the reduction in the EPNS, EENS, and SI, and a reduction in the amount of load shedding in the most critical contingencies compared with a base case (BaseCase) without a TVPPs.

Studies conducted by the EPE in Brazil on the economic attractiveness of a BESS BTM for the PDE 2032 (horizon planning up to year 2032) [13] demonstrated the partial economic attractiveness of this application, but only with a significant reduction in BESS costs. However, only captive consumers not participating in the ACL were considered, and a scheme with both PV systems and BESS BTM for MV consumers, as proposed in this work, has not been evaluated. The results of the case study in this work indicated the economic attractiveness of PV systems and the BESS scheme for MV consumers with current BESS costs, illustrating how synergies between PV systems and a BESS can be captured with a comprehensive methodology using optimization tools.

In this way, it is possible to characterize and quantify potential flexibility and the provision of ancillary services based on the aggregation of DERs in distribution systems such as TVPPs, thus streamlining the interaction between entrepreneurs, the DSOs, TSOs, and other stakeholders in terms of flexible transmission system planning.

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Abbreviations

The following abbreviations are used in this manuscript:

ACL	Free contracting environment
ADN	Active Distribution Network
ANAREDE	Network Analysis Program
ANEEL	National Electric Energy Agency
APE	Self-production of energy
BDGD	Geographic Database of the Distribution Utility
BDConf	Reliability database
BESS	Battery Energy Storage System
BPS	Bulk-Power System
BRP	Balancing Responsible Party
BTM	Behind-the-Meter
CEPEL	Electric Power Research Center
CVPP	Commercial Virtual Power Plant

CVU	Unit variable cost
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DNBM	Distribution Network Base Model
DR	Demand Response
DS	Distribution System
DSM	Demand-side Management
DSO	Distribution System Operator
EENS	Expected Energy Not Supplied
EPE	Energy Research Office
EPNS	Expected Power Not Supplied
ESS	Energy Storage System
FRVPP	Flexi-Renewable Virtual Power Plant
LOLD	Loss of Load Duration
LOLE	Loss of Load Expectation
LOLF	Loss of Load Frequency
LOLP	Loss of Load Probability
NASA	National Aeronautics and Space Administration
NH2	Composite Reliability Analysis and Operational Reserve Calculation Program
NPC	Net Present Cost
OpenDSS	Open Distribution System Simulator
OPF	Optimal Power Flow
PDE	Ten-year energy expansion plan
PGEN	Active power re-dispatch
PLD	Difference settlement price
POWER	Prediction of Worldwide Energy Resource
PPA	Power Purchase Agreement
PV	Photovoltaic
PVDG	Photovoltaic Distributed Generation
RCC	Robust Capability Curve
SP	São Paulo
SI	Severity index
SIN	National Interconnected System
TNBM	Transmission Network Base Model
TS	Transmission System
TSO	Transmission System Operator
TVPP	Technical Virtual Power Plant
TUSD	Distribution system use tariff
T&D	Transmission an Distribution
$TVPP_{MOG}$	Fictitious TVPP located in the municipality of Mogi das Cruzes
$TVPP_{SJC}$	Fictitious TVPP located in the municipality of São José dos Campos
$TVPP_{TAU}$	Fictitious TVPP located in the municipality of Taubaté
VPP	Virtual Power Plant

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