Puvi, Verner; Lehtonen, Matti

Stochastic Assessment of Voltage Unbalance Mitigation by Battery System in case of Single-Phase Solar Generation

Published in:
Proceedings of the International Symposium on Power Electronics, Electrical Drives, Automation and Motion, SPEEDAM 2018

DOI:
10.1109/SPEEDAM.2018.8445306

Published: 23/08/2018

Document Version
Peer reviewed version

Please cite the original version:
Puvi, V., & Lehtonen, M. (2018). Stochastic Assessment of Voltage Unbalance Mitigation by Battery System in case of Single-Phase Solar Generation. In *Proceedings of the International Symposium on Power Electronics, Electrical Drives, Automation and Motion, SPEEDAM 2018* (pp. 171-176). [8445306] IEEE. https://doi.org/10.1109/SPEEDAM.2018.8445306

Stochastic Assessment of Voltage Unbalance Mitigation by Battery System in case of Single-Phase Solar Generation

Verner Püvi and Matti Lehtonen

School of Electrical Engineering
Aalto University
Otakaari 1 B, 02150 Espoo, Finland
verner.puvi@aalto.fi, matti.lehtonen@aalto.fi

***Abstract*—The electric power system face big challenges today. Environmental concerns and political decisions that follows, are up to reshape electrical energy industry and change the way how energy is managed. One of the key ideas of forthcoming changes is to utilise renewable energy sources, such as solar. However, solar generation, as any other distributed generation, sets strain on the power system and power quality properties can be negatively affected. In this paper, the voltage unbalance (VU) caused by single-phase connected photovoltaics (PV) in residential low voltage grid are assessed by Monte Carlo Simulation (MCS). The voltage unbalance mitigation possibilities by battery energy storage system (BESS) are evaluated, by connecting the battery in a three different phase connection strategies. Two different stochastic assessment models will be tested: time independent and time series models. The results of the two models are presented and discussed in depth.**

I. Introduction

The photovoltaic (PV) solar generation is becoming an essential part of residential grids. It is one of the key renewable generation sources, that the technology level allows to harvest today. The policymakers, enforced by environmental problems, set the goal to increase the volume of distributed generation [1], [2]. Share of PV generation has grown significantly in recent years and is expected to grow even more [3], [4]. However, the distributed generation comes with a price of the power quality. Single-phase PV is a reason for the voltage unbalance (VU) in sparsely populated residential grids [5]. The VU can be mitigated by single-phase battery energy storage systems (BESS). The impact of PV and BESS on the VU is going to be analysed by Monte Carlo Simulation (MCS).

In this paper two goals are set:

1) Develop two MCS models for the VU assessment
2) Analyse possibilities of VU mitigation by BESS

Various studies have been done to evaluate the significance of the VU in a grid with distributed single-phase generation. A sensitivity analysis was conducted in [6]. The impact of PV location and rated power on the VU was evaluated by means of MCS.

In [7], [8], the stochastic methods of the VU assessment were developed. The probability density functions of the loads and PV generation were utilised and the quantities were randomly sampled at every iteration. The research presented in [9] have utilised the Taguchi's method to optimise the modelling process. It was shown, that Taguchi's method can increase the calculation speed without losing significant accuracy.

In [10], the MCS results of the VU were compared with deterministic VU calculation. Other than that, grid size, background VU and PV inverter size impact on VU were analysed. The MCS framework presented in [10] has heavily influenced the simulations in this article.

The solution for the VU problem can have different approaches. In [11], the possibilities of mitigating the VU by dynamic voltage restorer and distribution static compensator were analysed. In [12]–[14], the VU was compensated by a BESS. The one- and three-battery configurations were tested. The battery control algorithms were validated on an experimental set of devices emulating a grid.

In [15] the day-ahead scheduling framework of BESS was proposed. The framework covered multi-objective optimisation and stochastic models to simulate unscheduled events, such as islanded operation. The framework was applied on a microgrid hosting renewable energy sources and has proven, that grid can be optimised by scheduled BESS operation. The paper emphasises the importance of the time variable in a grid modelling and the framework can be applied in any time series algorithm.

II. Theory

The VU is a phenomenon in poly-phase electrical system, when the phase voltages have different magnitudes and the phase angles are offset. The reasons of occurrence are non-symmetrical loads, non-transposed distribution grid and non-symmetrical generation. The unbalanced phase voltages can create problems in a grid operation. Commonly occurred issues are decreased efficiency, higher utilisation factor and damage of electrical machines [16]–[18].

The VU calculation is based on the Fortescue sequence components, which allow to split the phase voltages into three sequence components as shown in Equation 1, where operator $a = 1 \cdot \angle 120°$ [19]. The VU is equal to a ratio of negative and positive sequence components and the VU tolerable limit is 2% [20]. The VU at every bus is found by means of the Transfer Impedance (TI). TI is a grid impedance model, which constitute a square matrix with mutual impedances. The square size is equal to the number of busses in a grid. The TI calculation in this paper is same as in [10].

$$\begin{bmatrix} v_{zero} \\ v_{pos} \\ v_{neg} \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \cdot \begin{bmatrix} v_a \\ v_b \\ v_c \end{bmatrix} \tag{1}$$

III. METHODOLOGY

In order to mitigate the VU, the BESS is going to be connected in three different strategies. The impact of each strategy on the VU is going to be observed.

- Strategy 1 - Random phase
- Strategy 2 - Same phase as PV
- Strategy 3 - Phase with highest voltage level

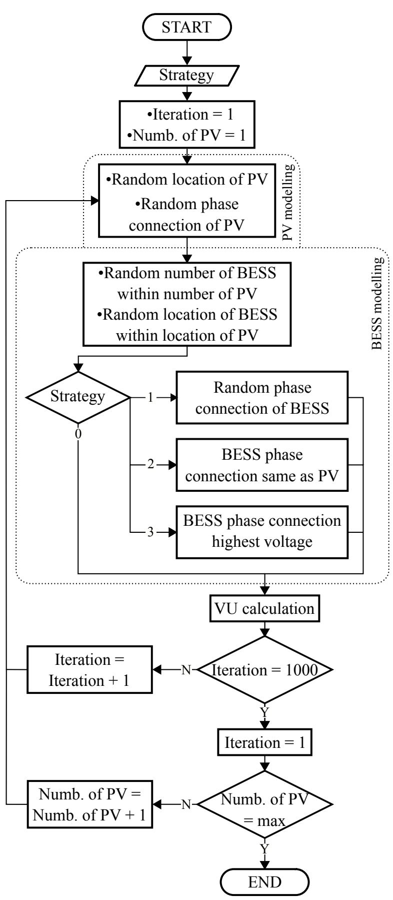

Fig. 1. Flowchart of the time independent algorithm

A. Modelling

The PV and BESS are assumed to be constant current models. The PV maximum current is equal to standard single-phase circuit size of 16 amperes and the BESS continuous power and efficiency is assumed to be as per [21].

The input data for the time series model are a one year arrays of solar generation and load demand. The solar generation pattern follows theoretical maximum generation, without any weather conditions considered [22]. The load demand patterns are real metered data from three households in Finland with different heating types: storage heating, district heating and direct electric heating.

The three grids considered represent three different areas in Finland based on NUTS subdivision: predominantly rural (PR), intermediate (IN) and predominantly urban (PU). The grid parameters and topologies utilised are the same as in [23].

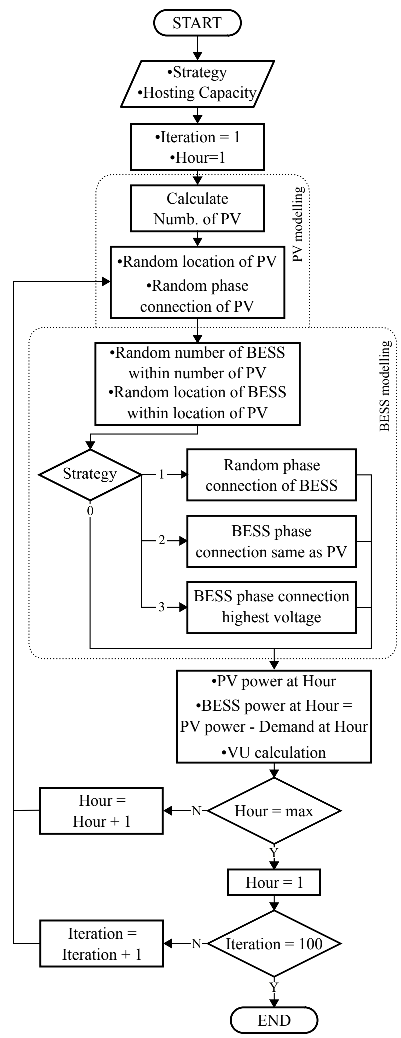

Fig. 2. Flowchart of the time series algorithm

B. Monte Carlo Simulation

Two models will be simulated: the time independent and time series models. Within the time independent algorithm, PV and BESS values are randomly sampled and VU is calculated at every iteration, Figure 1.

The time series model has same PV and BESS modelling principle. However, it utilizes different approach for the loop. The number of PVs is fixed by the Hosting Capacity (HC), the values of which are increased until reaches limits presented in [23]. The PV current is taken from the input data and the BESS current is defined as the difference of solar generation and load demand. The loads are assumed to be symmetrical and not causing VU. The time series algorithm can be seen on Figure 2.

All the random variables are sampled with uniform distribution. The HC is defined as a ratio of maximum solar generation power along a year and maximum load demand along the same year. Three levels of HC were considered in this paper, representing different numbers of PVs.

The stochastic approach has advantages in VU assessment and grid planning applications. In calculations with many input variables, it is faster to randomly generate variables repetitively, rather than simulating all possible combinations of inputs. Likewise, the stochastic model allows to utilise probabilistic input variables in form of probability distributions. Lastly, the results of MCS can be statistically analysed.

IV. Results

A. Results of Time Independent Model

The results of time independent model are presented in Figures 3-5. The 95th percentile VU values are shown with respect to the number of PVs in a grid. The four lines on the plots represent different strategies. For comparison reasons, the grey line representing solar only scenario is added (strategy 0).

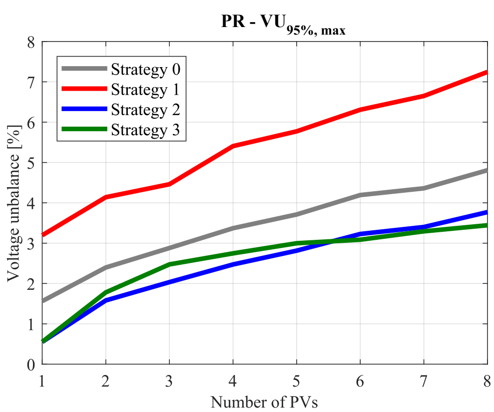

Fig. 3. VU dependency on number of PVs at different strategies in PR region

In PR region with only the PVs in the grid, the VU limit is exceeded at 2 PVs out of 8 possible. At strategy 2 and 3, the second PV can be connected. However, at strategy 1, none of the PVs will be tolerable in the grid.

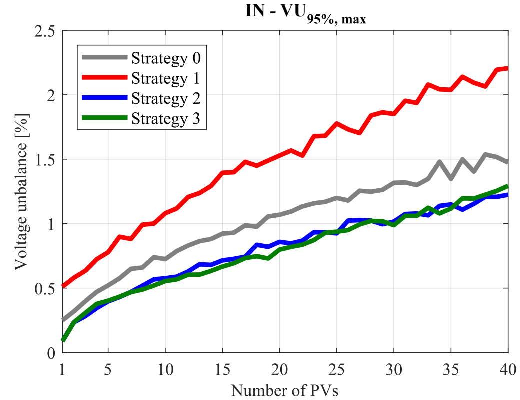

Fig. 4. VU dependency on number of PVs at different strategies in IN region

In IN region at solar only case, the VU can reach 1.5% at high number of PVs. At strategies 2 and 3, the VU can be lowered to 1.25%. At strategy 1, the VU can reach the limit of 2% at around 33 PVs out of 40, having 4 PVs per each 10 busses.

In PU region, PV alone can cause VU up to 1.1%. The strategy 2 can lower the VU to 0.9%. Strategy 3 demonstrates good VU mitigation efficacy, but starting at 40 PVs, the VU level rises linearly, while at other strategies VU saturates at some value. At strategy 1 the VU can reach 1.5%, but nevertheless all values are below the limit. In PU region, there are 5 busses, 60 customers per bus.

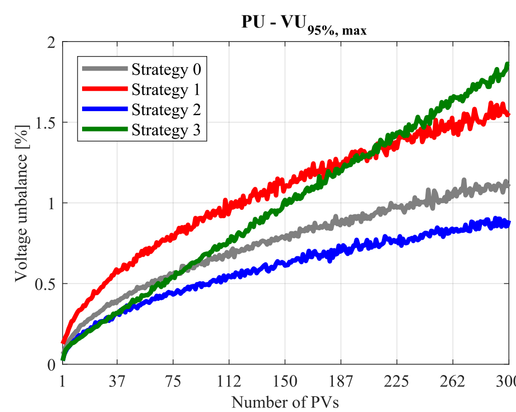

Fig. 5. VU dependency on number of PVs at different strategies in PU region

B. Result of Time Series Model

The results of the time series model are presented in Tables I-V. Firstly, the peak values of the 95th percentile voltage unbalance are shown on Tables I-IV. The highest peak value within a season is recorded for every HC, region and strategy. Secondly, the number of the 95th percentile VU violations as per [20] are listed per season.

TABLE I
VU PEAK VALUES OVER THE SEASONS AT SOLAR ARRAYS ONLY

Strategy 0		Highest peak values of $VU_{95\%, max}$			
	PV HC	Winter	Spring	Summer	Autumn
PR	25%	2.07	2.21	2.10	2.04
	75%	3.57	3.78	3.57	3.47
	125%	3.94	4.17	3.94	3.83
IN	25%	0.69	0.73	0.69	0.67
	75%	1.26	1.33	1.26	1.22
	125%	1.24	1.31	1.24	1.21
PU	25%	0.31	0.33	0.31	0.30
	75%	0.52	0.55	0.52	0.50
	125%	0.72	0.76	0.72	0.70

The results of strategy 0 (solar only) is shown in Table I. In PR region, the VU is exceeding the limit of 2% at all the HC levels modelled. In IN region, the VU is below 1.5% and at PU region, the VU is below 1% and does not exceed the limit.

TABLE II
VU PEAK VALUES OVER THE SEASONS AT STRATEGY 1

Strategy 1		Highest peak values of $VU_{95\%, max}$			
	PV HC	Winter	Spring	Summer	Autumn
PR	25%	2.19	2.41	2.37	2.28
	75%	3.91	4.23	4.06	3.92
	125%	3.91	4.40	4.41	4.11
IN	25%	0.78	0.85	0.83	0.80
	75%	1.10	1.17	1.08	1.07
	125%	1.56	1.71	1.61	1.56
PU	25%	0.35	0.38	0.36	0.35
	75%	0.63	0.67	0.64	0.62
	125%	0.78	0.81	0.77	0.75

The results of strategy 1 are shown on Table II. At PR region, the VU levels can exceed 4% at high HC. At IN region, the VU can reach 1.7% at spring, staying under the limit. At PU region, the VU can reach 0.8%, staying below the 2% limit.

TABLE III
VU PEAK VALUES OVER THE SEASONS AT STRATEGY 2

Strategy 2		Highest peak values of $VU_{95\%, max}$			
	PV HC	Winter	Spring	Summer	Autumn
PR	25%	1.72	1.68	1.39	1.68
	75%	2.69	2.78	2.60	2.56
	125%	3.18	2.86	2.60	2.82
IN	25%	0.58	0.55	0.47	0.54
	75%	1.08	1.04	0.87	1.03
	125%	1.32	1.23	1.12	1.22
PR	25%	0.27	0.27	0.23	0.27
	75%	0.50	0.48	0.42	0.48
	125%	0.69	0.65	0.50	0.65

The results of strategy 2 are shown on Table III. At PR region, the 3.1% of the VU can be expected. At IN region, the VU ca reach 1.3% and at PU region, the VU can barely reach the level of 0.7%.

TABLE IV
VU PEAK VALUES OVER THE SEASONS AT STRATEGY 3

Strategy 3		Highest peak values of $VU_{95\%, max}$			
	PV HC	Winter	Spring	Summer	Autumn
PR	25%	1.82	1.82	1.24	1.82
	75%	5.72	5.35	2.69	5.31
	125%	7.11	6.67	3.00	6.61
IN	25%	1.11	1.08	0.51	1.07
	75%	3.59	3.33	1.20	3.31
	125%	5.50	5.15	1.83	5.10
PU	25%	0.86	0.85	0.34	0.85
	75%	2.59	2.57	0.93	2.57
	125%	4.46	4.43	1.42	4.42

The results of strategy 3 are shown on Table IV. At PR region, the VU can reach 7% in winter, however will stay at 3% in summer. At IN region, the pattern is similar, having VU around 5%, except for summer, when VU is below the limit. At PU region, the VU will be below 2% in summer and during the rest of the year over 4%.

TABLE V
VU VIOLATION COUNT AS PER EN 50160 OVER THE SEASONS

Number of weeks when $VU_{95\%, max}$ violated the limit					
PR	PV HC	Winter	Spring	Summer	Autumn
Strategy 0	25%	0	2	0	0
	75%	23	30	29	25
	125%	23	34	30	26
Strategy 1	25%	3	8	7	4
	75%	40	44	36	29
	125%	44	46	36	29
Strategy 2	25%	0	0	0	0
	75%	23	23	14	11
	125%	31	25	14	12
Strategy 3	25%	0	0	0	0
	75%	75	39	19	19
	125%	99	63	22	45
IN Strategy 3	25%	0	0	0	0
	75%	20	10	0	10
	125%	29	10	0	10
PU Strategy 3	25%	0	0	0	0
	75%	8	4	0	4
	125%	10	5	0	5

The VU limit violation count is shown in Table V. The limit is violated mostly at PR region. At strategy 0, the violation count can reach 34, at strategy 1 - 46, at strategy 2 - 31 and finally at strategy 3 - 99 times. The strategy 3 can cause voltage limit violations at IN region - up to 29 times and at PU region - 10 times.

V. Conclusions and Discussion

A. The models

The two models were built for stochastic VU assessment. The time independent model is much faster to calculate the VU. Depending on the length of input data, the time series model takes more time to simulate. The VU calculation during a year takes several hours.

On the other hand, time series model allows to calculate the VU at every single hour or any other time step. The peak times of VU can be found, which would help to find a reason of occurrence. Also, the VU can be found during the occasional events, such as public holidays or any other people's lifestyle portraying occasion.

B. Results

The results revealed, that assessed VU levels of two models do not quite match. There are several reasons that cause the difference and some of them will be discussed here. Prospects for further model modifications will be proposed, which would support developing a hybrid model for stochastic VU assessment.

In the time series model, the PV generation and BESS supply varies over time. This makes the average value of imbalanced current lower. The time independent model considers rated currents at every iteration, resulting in higher VU.

The time series model allows to analyse the seasonal difference of the VU. Due to cyclic solar irradiance and heating load demand, the VU levels are different throughout the year. Strategies emphasise seasonal differences and reveal the effect of PV and BESS on the VU. At strategy 0, no BESS were considered and thus the VU was caused only by PV. The VU has higher levels due to lower temperature in Spring and high solar irradiance in summer. At other strategies, the load demand is causing the BESS to supply the grid. At high demand times, the BESS can supply significant power and cause high VU levels. High VU is common in winter in case if PV is coupled with BESS.

In the results of the time independent model, the VU saturation trend can be noticed. By increasing the number of PVs in a grid, the VU increases at relatively high pace. However, when number of PVs is high, the growth tends to slow down. Reason behind this phenomenon can be the fact, that by increasing the number of PVs, the probability of having all PVs in the same phase decreases. Any next PV added to the grid has smaller contribution to the VU than previous one.

Another trend can be observed. Bigger grids with higher customer density and more radial feeders tend to have lower VU. The predominantly urban grid has lower VU values than predominantly rural grid. Higher number of customers per bus makes high levels of VU less probable. As it was mentioned before, high number of PV or BESS will most likely be connected to different phases and thus balancing the VU. Also, feeder and transformer impedances are lower in big grids. The smaller impedance values in the TI causes lower negative sequence voltage drop. Finally, customers in bigger grids located in urban areas are within reach of district heating utilities. District heating covers heating demand of a household and thus BESS has no need to supply high single-phase current.

C. Voltage unbalance mitigation

The strategy 0 comprises a solar only case. It is used as a reference for other strategies. Connecting BESS and PV to random phases, as meant in strategy 1, will increases level of VU in a grid. Having BESS and PV in the same phase, as in strategy 2, will decrease the VU.

Strategy 3 has ambiguous results. The results of time independent model reveal, that at low number of PVs, strategy 3 has good VU mitigating possibility, better than strategy 2. On the other hand, at the high number of PVs, the VU tend rise over the levels of strategy 2.

Time series model results show, that strategy 3 has the highest VU levels among all other cases. This can be explained by the fact of load demand being supplied by BESS. It is partly true. However, the strategy logic is not ideal for the VU mitigation. Connecting BESS to phase with highest voltage works well in case of solar power excess. When the BESS is supplying the load though, it raises the voltage in the phase it is connected. This leaves no chance for the next BESS to be connected to other phase. It would be more beneficial, if the BESS would be connected to highest phase while charging and lowest phase while supplying.

D. Discussion

The HC parameter is used in this research to quantify the PVs in time series model. However, the HC can give misleading idea about the quantity of the PVs. It is important to mention the single PV power outputs in VU assessment context. At the same HC, the higher number of low power PVs will cause lower VU compared to lower number of high power PVs.

In case of stochastic modelling, the HC parameter has an uncertainty factor. The maximum total load power is considered in the HC calculation. In stochastic modelling, the load can vary at every simulation run due to the randomness in load modelling. Instead, the HC parameter could be tied with the secondary transformer, which feeds the grid. The transformer power rating is constant at every iteration and in well planned grid, it represents the capacity of the grid and highest possible load demand.

References

[1] European Commission, *"Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC,"* Official Journal, L 140/16, 2009

[2] *D&I Alert – Energy, Infrastructure Natural Resources. New Support Scheme for Renewables in Finland as of 2018*, Dittmar & Indrenius, the 25th November 2016

[3] *Global Market Outlook For Solar Power 2017-2021*, SolarPower Europe

[4] *Sähköverkkoon kytketty aurinkosähkökapasiteetti yli kolminkertaistui vuodessa*, Energiavirasto, Language Finnish, June 2017

[5] F. Katiraei, K. Mauch and L. Dignard-Bailey, *Integration of Photovoltaic Power Systems in High-Penetration Clusters for Distribution Networks and Mini-Grids*, International Journal of Distributed Energy Resources, Vol. 3, 2007

[6] F. Shahnia, R. Majumder, A. Ghosh, G. Ledwich and F. Zare, *Sensitivity analysis of voltage imbalance in distribution networks with rooftop PVs*, Providence, RI, USA, 2010, DOI: 10.1109/PES.2010.5590149

[7] N. Safitri, F. Shahnia, and M.A.S. Masoum, *Stochastic analysis results for coordination of single-phase rooftop PVs in unbalanced residential feeders*, Brisbane, QLD, Australia, 2015, 1-5, DOI: 10.1109/APPEEC.2015.7381053

[8] F.J. Ruiz-Rodriguez, J.C. Hernández, and F. Jurado, *Voltage unbalance assessment in secondary radial distribution networks with single-phase photovoltaic systems*, International Journal of Electrical Power & Energy Systems, Vol. 64, 646-654, 2015, DOI: 10.1016/j.ijepes.2014.07.071

[9] G. Carpinelli, R. Rizzo, P. Caramia and P. Varilone, *Taguchi's method for probabilistic three-phase power flow of unbalanced distribution systems with correlated Wind and Photovoltaic Generation Systems*, Renewable Energy, Vol. 117, 227-241, 2018, DOI: 10.1016/j.renene.2017.10.048

[10] D. Schwanz, F. Möller, S.K. Rönnberg, J. Meyer, and M.H.J. Bollen, *Stochastic assessment of voltage unbalance due to single-phase-connected solar power*, Belo Horizonte, Minas Gerais, Brazil, 2016, 95-103, DOI: 10.1109/ICHQP.2016.7783353

[11] F. Shahnia, A. Ghosh, G. Ledwich and F. Zare, *Voltage Correction in Low Voltage Distribution Networks with Rooftop PVs using Custom Power Devices*, Melbourne, VIC, Australia, 2011, DOI: 10.1109/IECON.2011.6119330

[12] K.H. Chua, J. Wong, Y.S. Lim, P. Taylor, E. Morris and S. Morris, *Mitigation of Voltage Unbalance in Low Voltage Distribution Network with High Level of Photovoltaic System*, Energy Procedia, Vol. 12, 495-501, 2011, DOI: 10.1016/j.egypro.2011.10.066

[13] K.H. Chua, Y.S. Lim, P. Taylor, S. Morris and J. Wong, *Energy Storage System for Mitigating Voltage Unbalance on Low-Voltage Networks With Photovoltaic Systems*, IEEE Transactions on Power Delivery, Vol. 27, 1783-1790, 2012, DOI: 10.1109/TPWRD.2012.2195035

[14] J. Wong, Y.S. Lim, S. Morris, E. Morris and K.H. Chua, *Fuzzy-driven energy storage system for mitigating voltage unbalance factor on distribution network with photovoltaic system*, AIP Conference Proceedings, Vol. 1828, Issue: 1, 020019, 2017, DOI: 10.1063/1.4979390

[15] H. Farzin, M. Fotuhi-Firuzabad and M. Moeini-Aghtaie, *A Stochastic Multi-Objective Framework for Optimal Scheduling of Energy Storage Systems in Microgrids*, IEEE Transactions on Smart Grid, Vol. 8, Issue: 1, 117-127, 2017, DOI: 10.1109/TSG.2016.2598678

[16] L.F. Ochoa, R.M. Ciric, A. Padilha-Feltrin, and G.P. Harrison, *Evaluation of distribution system losses due to load unbalance*, Liège, Belgium, 2005

[17] K. Ma, R. Li, and F. Li, *Quantification of Additional Asset Reinforcement Cost From 3-Phase Imbalance*, IEEE Transactions on Power Systems, Vol. 31, Issue: 4, 2885 - 2891, 2015, DOI: 10.1109/TPWRS.2015.2481078

[18] D.H. Harrison, *Voltage unbalance on rural systems*, Power Engineering Journal, Vol. 1, Issue: 3, 149 - 153, 1987, DOI: 10.1049/pe:19870028

[19] J.J. Grainger and W.D. Stevenson,Jr, *Power System Analysis* Singapore: McGraw-Hill Book, Co, 1994.

[20] *Voltage characteristics of electricity supplied by public electricity networks*, SFS-EN 50160, 2010.

[21] *Tesla Powerwall 2 AC Datasheet*, TESLA, INC, USA, 2016. [Online]. Available: http://www.energymatters.com.au/wp-content/uploads/2016/11/tesla-powerwall-2-datasheet.pdf.

[22] J. Ekström, M. Koivisto, J. Millar, I. Mellin and M. Lehtonen, *A statistical approach for hourly photovoltaic power generation modeling with generation locations without measured data*, Solar Energy, Vol. 132, 173-187, 2016, DOI: 10.1016/j.solener.2016.02.055

[23] A. Arshad, M. Lindner and M. Lehtonen, *An Analysis of Photo-Voltaic Hosting Capacity in Low Voltage Distiribution Networks*, Energies, Vol. 10, Article number: 1702, 2017, DOI: 10.3390/en10111702