Size Optimization of a Microgrid with Large Penetration of PV and Battery Energy Storage System

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ABSTRACT - Microgrids (μG) are an emerging and promising concept for the integration of distributed Renewable Energy Sources (RES) into the power grid by introducing local coordination of controllable distributed energy sources. The University of Cyprus (UCY) plans to evolve the whole campus into a μG with a 10 MWp PV and respective Battery Energy Storage System (BESS). The campus is ideal for a μG because it is connected to the national grid through only one Point of Common Coupling (PCC). The μG will target, among others, the reduction of the UCY electricity bill (e.g. by improved time of use and self-consumption) and will provide ancillary services such as voltage regulation at the PCC. This paper presents an analysis on optimizing the required PV power and BESS size (power and energy), control and technology based on the University's load profile and the solar insolation in Cyprus. Furthermore, the cost of the proposed solution and operational reliability / flexibility of the system are compared for a centralized (single BESS for the whole campus) and distributed (one BESS per faculty building) storage solution. The imported and exported energy from/to the grid is priced based on the net-metering scheme that is currently in place in Cyprus. In addition to the flat net-metering tariff, the energy management system will utilize a simulated time of use tariff (Peak, Off-Peak, Intermediate) aiming to achieve peak shaving during peak hours by the use of PV and stored energy from off-peak hours. It is planned to analyse and determine the optimum BESS size and technology based on the tariff scheme, load and battery capital cost. It is therefore imperative that the optimum size and technology of the BESS is obtained in order to avoid a long payback period and to meet the UCY campus requirements.

Keywords – photovoltaic (PV), battery storage, microgrid, size optimisation, cost-optimal

1. Introduction

The integration of renewable energy resources (RES) in microgrids has been increasing in recent years. Non dispatchable renewable distributed energy resources (DER) are considered as a faster and cheaper alternative for supplying electricity to remote areas rather than upgrading the existing utility grid infrastructure while also considered as an environmentally friendly solution for improving the reliability and decreasing the cost of microgrid systems. The increasing penetration of DERs, such as Photovoltaics (PVs), in the distribution system can adversely impact the reliability and security of supply because of their uncontrollable nature and intermittency. In view of the above, the use of battery energy storage systems (BESS) can, among others, play a vital role in improving the distribution system operation, damping out the supply variability caused by intermittent resources, load levelling, and reducing system peaks demand [1]. Furthermore, the operation of BESS and charging/discharging times should be controlled to provide as many benefits to the grid as possible. Moreover, in order to increase the benefit gained from the BESS, more than one service can be synthesized at the same time leading to the need for more investigation to choose the optimal operation and planning decisions. For this reason, it is imperative to determine the optimal size of the integrated BESS in order to gain the desired economical and reliability benefits.

It is known that small BESS may not provide adequate economic benefits, desired flexibility or predefined reliability objectives in the microgrid and that large BESS impose higher investment and maintenance costs to the microgrid [1], [2]. Much research work has been done to address the question of the optimal BESS sizing [1]–[3]. At present, most research focuses on the optimization of the size of BESS in microgrids that consist of DERs, but rarely involve the optimization of both DERs and BESS siting and sizing.

The installation of generation or storage systems at strategic locations could reduce line loadings and losses. Benefits of distributed locations of resources include transmission and distribution savings because of the deferral of line upgrades, improvement in service reliability, and reduction of line losses. However, decentralized storage can limit the available capacity for charging and therefore any excess energy produced by the PV system will have to be fed into the grid. Therefore, a more centralized approach can be considered through the use of an aggregator. A crucial benefit when having a central stationary battery system installed is the possibility to choose the connection point between the storage and the grid in order to have an influence on the voltage quality in the distribution grid [4].

Generally, the campus of Universities is large with many facility and residence buildings distributed around. The relatively long distances in the campus and the high power required by the large campus buildings and especially laboratories imposes that increased power will be lost in the interconnecting cables. The distributed nature of the campus makes Universities a good choice for DERs to be installed and transform the campus to a microgrid aiming to improve voltage regulation and reduce peak power exchange from the grid to reduce power loss in the cables and transformers. For these reasons and due to the fact that the UCY is connected to the national grid via a single point of common coupling (PCC), it is planned to transform its campus to a microgrid with an estimated 10 MWp PV and respective battery storage.

This paper outlines a modelling approach to obtain optimal sizing and location of battery storage as well as the peak PV power required by using the UCY campus load and electricity tariffs as a case study. The developed methodology considers the intermittency (clouds) of solar PV generation and its variation due to environmental conditions while achieving the most economical solution. The sizing strategy aims to take advantage of the available PV generation to limit the campus peak load to a minimum billing demand. The main objective of the proposed method is to find the optimal size of the BESS that maximizes the annual benefits of the university campus as well as the optimal BESS siting (centralized or decentralized) that minimizes the power losses in the cable interconnections of the campus.

The rest of the paper is organized as follows: Section 2 briefly presents the University campus current situation while explaining the modelling of the system and the methodology followed. Section 3 presents the results and finally conclusions are presented in Section 4.

2. Methodology

The present and future load and electricity tariffs of the UCY campus are analysed in this section. The approach and methodology followed to determine the cost-optimal size and siting of the BESS and PV plant peak power is described along with the methodology to compare power loss in the cables of centralised with decentralised battery storage.

2.1 Load Analysis of the UCY Campus

Distribution of electricity at the University's facilities and departments is made possible by a primary distribution substation which supplies two 11 kV feeders and with the provision of a third feeder in the future. The primary substation serves as the point of common coupling (PCC) of the campus electrical network to the national grid. Each feeder supplies local substations within the campus that are used to power the different buildings and facilities of the University resulting in 12 local substations in total. Fig. 1 depicts the electrical line diagram of the campus including all the components and the of the cables characteristics. The feeders can be configured as a ring topology, however, they are disconnected at the break points shown.

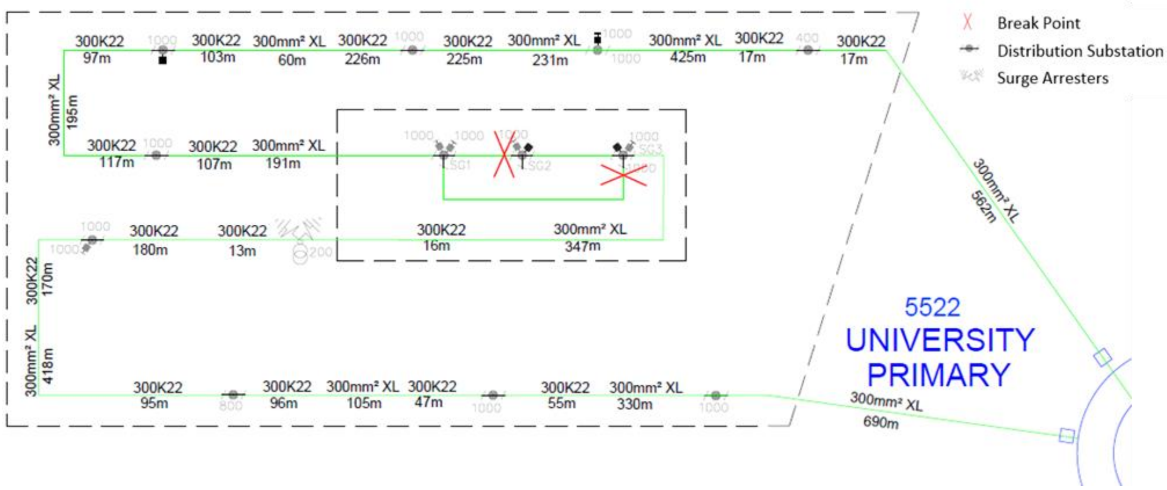

Fig. 1. UCY campus electrical line diagram.

Being a university campus, the UCY has a relatively high energy consumption with a small percentage covered by distributed PV systems within the campus rated at a total capacity of 400 kWp. The annual peak demand of the UCY campus occurs during July and usually is around 3500 kVA, divided into 1400 kVA and 2100 kVA for feeder A and B respectively. However, the energy consumption and the peak demand of the UCY is expected to increase by the end of 2017 due to the planned campus expansion. Based on the estimated annual consumption of the forthcoming facilities, the future peak demand is expected to rise up to 1.6 times the current one. The current and future annual load profiles are illustrated in Fig. 2.

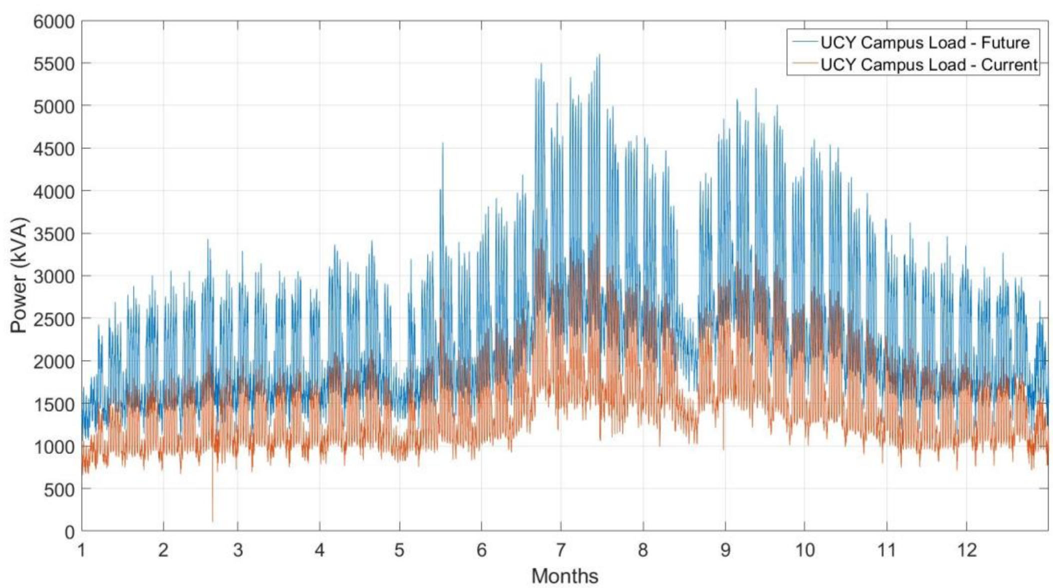

Fig. 2. Current UCY campus load (year 2016) and estimated future load. The data was sampled in 15mins intervals.

For the time being, the electricity tariffs paid by the University are based on predefined Time of Use (ToU) tariffs. The tariffs are based on the monthly load factor (LF) which is calculated as the ratio of the total energy consumption recorded during the month to the maximum demand times the number of hours in that month. The current and future mean load factor (LF) per month was calculated to be equal to 0.55. The ToU tariffs currently paid by the University are shown in Table I.

TABLE I. TARIFF PERIODS AND RATES BASED ON THE MONTHLY LOAD FACTOR

Period	Description	Hours	Monthly Load Factor (LF)		
			0-30%	***31-60%***	***61-100%***
Peak Period (June to September and from Monday to Friday inclusive)	For every kVA of the Monthly Maximum Demand	09:00 – 17:00	€13.99	€15.81	€16.99
	Per unit (kWh) charge depending on the Monthly LF		€0.1604	€0.1268	€0.1159
Intermediate Period	For every kVA of the Monthly Maximum Demand	all remaining hours	€1.36	€1.97	€4.54
	Per unit (kWh) charge depending on the Monthly LF		€0.1276	€0.1197	€0.1075
Off-Peak Period	Per unit (kWh) charge depending on the monthly LF	23:00 – 07:00	€0.1087	€0.1059	€0.1048

In order to find out in which tariff periods there is the highest electricity demand, the required energy and maximum power per day for the campus load in year 2016 was analysed. Fig. 3 demonstrates that most of the energy consumption falls within the Peak period (June to September) which corresponds to the highest tariff rate and to a lesser extent in the Intermediate period. Likewise, the maximum power during the day appears in both Peak and Intermediate periods. Consequently, in order to reduce the inevitable high electricity cost of the campus, a method that will help to reduce the energy consumption and "clip" the peak power demand in the expensive Peak and Intermediate periods is essential.

For this purpose, a control algorithm based on load shaving has been developed aiming to reduce the electricity cost paid by the University as described in section 2.2 of the methodology.

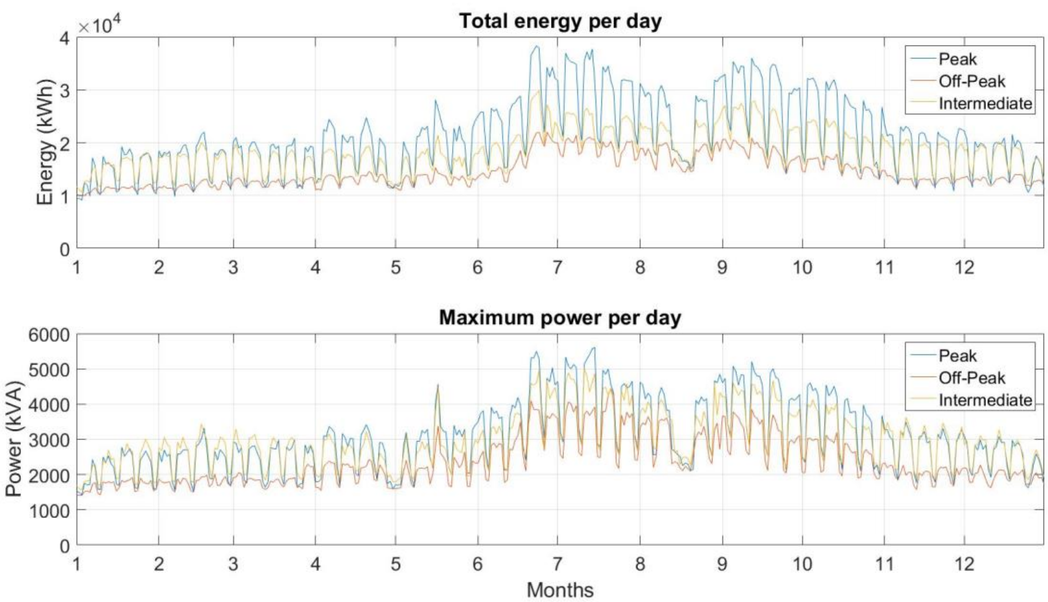

Fig. 3. UCY campus total daily energy and maximum power requirement per tariff period. The x-axis is in months instead of days because the electricity consumed is paid every month and it is easier to figure out in which months the demand is higher.

2.2. Control Algorithm

The initial control algorithm was developed in a test, UCY performed by using the real hardware of DERs at the Technical University of Denmark (DTU) to obtain preliminary results about the voltage variation at the PCC by the transformation of the electrical network of the campus to a microgrid [5]. The aim of this algorithm is to perform energy management by charging the battery from PV production or in cheap tariff Off-Peak periods and use the energy in Peak and Intermediate periods in which the electricity tariffs are high to reduce both the energy and maximum power drawn from the grid (load shaving). It is not cost effective to export the PV energy to the grid since it is bought by the Electricity Authority of Cyprus at a variable low rate avoidance cost (€0.05 on average) which is defined on a monthly basis.

In that test, a 10 MWp PV and 1 MW / 1 MWh battery was assumed and in the initial control algorithm, the battery was charged to 50% at night during Off-Peak period (cheap tariffs) and was also charged from PV during the day. The battery was used to perform load shaving in Peak and Intermediate periods in order to reduce the electricity bill of the University. The 50% charge at night was done to ensure peak shaving in the next day in the absence of enough PV power. In this work, the algorithm functionality was kept the same but with the goal to optimise the PV power, battery size (energy and power) and energy management parameters to achieve the best annual benefit in terms of electricity cost.

A difference between the initial and the current algorithm is that the charging power in the Off-Peak period is calculated based on the actual SOC and the target SOC and a charging period of 8 hours (off-peak duration, 23:00 to 07:00). This was done in order to decrease the maximum power demand and keep the LF as high as possible. It also increases the battery's efficiency due to the lower charging power.

From Fig. 3, it can be seen that the maximum power per day is different, hence a different load shave value is required on a daily basis in order to achieve the lowest possible electricity cost. In order to achieve this, a parameter called 'load clip' was defined and used in this work to calculate the daily load shave value. Therefore, the daily load shave value was calculated by subtracting the load clip value, which was the same for all days, from the daily maximum power. If the calculated load shave was negative, it was limited to zero. As it will be seen later, the load clip was a value to be optimised since it affects the size of the battery.

Simulation

The control algorithm and modelling were developed in MATLAB and have been run multiple times under different test cases in order to find the optimum battery size and energy management parameters. The test cases and the parameters which were optimised are described in section 2.4 of the methodology. A different approach was followed to optimise the PV power as described in the following section.

2.3. PV Size Calculation

The University targets to become a zero energy institution, i.e. the net energy in a period of one year has to be equal to zero. To estimate the required PV power, the total yearly energy demand of the campus was calculated and then the peak PV power needed to produce the same energy was extracted. To obtain realistic results, the output power of a 1 kWp multi-crystalline PV system at UCY was considered as a reference (includes power variation due to natural weather changes such as clouds and ambient temperature) and then scaled up to meet the yearly energy demand of the campus. Multi-crystalline silicon is the technology of choice since it is cheap, reliable and has a proven track record in Cyprus [6], [7]. The required PV power was estimated on a yearly basis for 5 consecutive years and then the average of the 5 years was taken as the peak PV power to be installed. The average power factor (PF) of the campus load in a year (0.95) and a 1% degradation per year for the PV modules was included in the calculations as well. The calculated PV power was used as an input in the battery optimisation procedure which is described in the following section.

2.4. Battery Size Optimisation

Battery optimisation is essential to achieve high energy savings and a reasonable payback period. The target is to find the optimum battery capacity and power to achieve the lowest electricity cost in the lifetime of the system which is assumed to be 20 years. The most probable candidate for the University's microgrid is the lithium-ion battery technology due to its high efficiency, energy density and cycle and calendar life [8], [9].

To estimate the optimum battery size (energy and power), two battery related parameters were optimised based on a yearly basis simulations. The first parameter was the battery power, which was set equal to the load clip value (see section 2.1 for explanation). The second parameter was the SOC limit during Off-Peak hours, which affects the charging energy cost and the availability of enough energy to perform load shave during the first hours (before PV power is available) of the next day. The usable battery capacity was set equal to the battery power value since lithium-ion batteries have a long life time when their operating power is less than 1C [10], [11]. Those two parameters were set to a range of values as shown in Fig. 5 and different combinations of those values were simulated resulting in 253 test cases.

The average yearly PF of the UCY campus load is 0.95 but to simplify the calculations, the PF was assumed to be equal to 1. This does not affect the results significantly since the parameters are optimised on a daily basis and not on a yearly basis like in the case of PV power calculation.

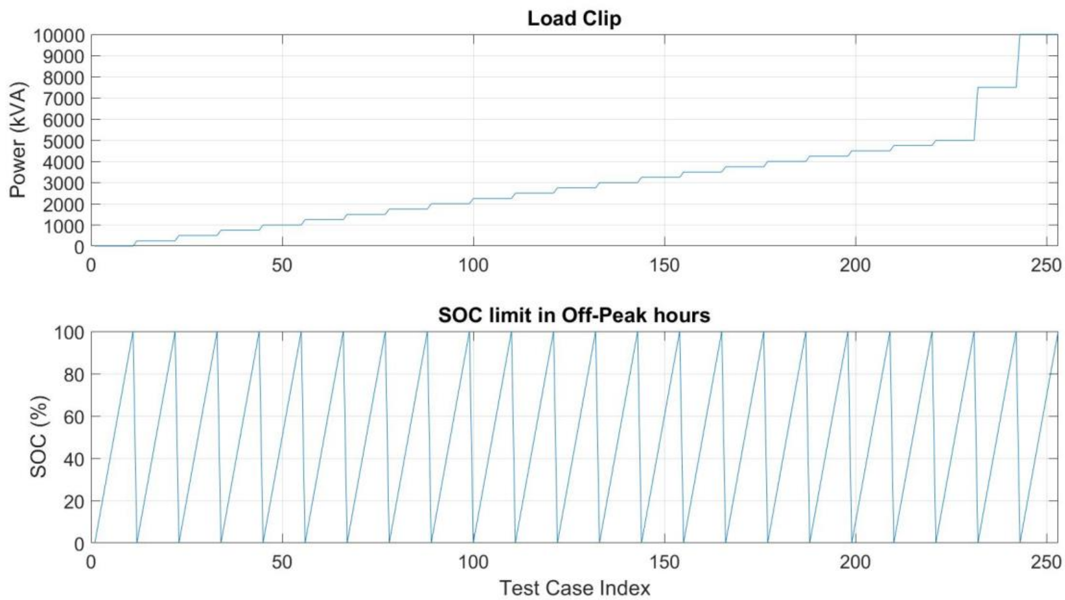

Fig. 4. Parameters for optimisation used during battery sizing. The battery usable capacity and power were set equal to the load clip value. Although not obvious, the SOC limit varies in 10% steps.

For the calculation of the investment cost, payback period and savings a price of €1/W was assumed for both the PV and battery system. Also, no depreciation or interest rates were included in the calculations. In order to have a long lifetime and be able to be charged/discharged at a constant power, lithium-ion batteries have to be operated within the region of 20% to 90% SOC [12]. This limits the battery's usable capacity to 70% and hence in the battery investment cost the battery's capacity was multiplied by a factor of 1.43 to accommodate for the limiting 70% depth of discharge (DOD). In addition a factor of 1.25 was included in the cost calculation to accommodate for the calendar life time reduction in battery capacity [13]. The battery was assumed to have an efficiency of 90%.

2.5. Centralised vs Decentralised Battery System Feeder Cable Power Loss

The electrical network of the University campus offers the capability to configure the battery as centralised or decentralised system. This is possible because all the local campus distribution substations are connected to a central primary substation by two feeder cables as seen in Fig. 1. Therefore, an analysis was done to find the solution that results in the lowest power loss in the feeders' cable.

To estimate the feeders' cable power loss, the length of each feeder's cable was estimated according to the distance values between the different substations shown in Fig. 1. Although only two feeders are active at the moment, the third future feeder was included in the power loss analysis. The cable was divided into sections, with each section representing the distance between the relative substations at the cable's ends. The resistance of each section was calculated and then its power loss was obtained based on the power flowing in that section of the cable. The feeder cables are aluminium with XLPE insulation and have a cross sectional area of 300 mm^2. The temperature variation of the cable resistance was not considered in the calculations. Due to the unavailability of data for the load of each substation in the campus, it was assumed that the load of each substation is a proportion of the total campus load based on the ratio of each substation estimated load to the total campus load. The total campus load was obtained by performing a simulation on a 15min time base with the calculated PV power and the optimised battery size and control algorithm parameters.

3. Results

This section presents the results for PV size calculation and battery size optimisation. The criteria for the optimum battery size are discussed along with the results of power loss of the cable of the feeders between a centralised and decentralised battery system obtained by using the aforementioned methodology.

4.1. PV Size Calculation

This section presents the results of calculating the peak PV power with the methodology described in section 2.3. The estimated required peak PV power is 10.48 MW, which is close to the initial 10 MW assumption when the preliminary voltage variation at the PCC test was done at DTU [5]. Therefore, a 10 MW PV system will be used in the battery optimisation simulations and will also be installed at the University's campus. This will result in an investment cost for PV of €10 M.

4.2. Battery Size Optimisation

As mentioned before, the battery size was optimised based on two related battery parameters which were combined into different test cases. To assess the test cases and find the most optimum solution, the savings over a period of 20 years, the LF and the battery cycles were assessed for 5 consecutive years of PV production. The capacity of the battery mentioned in the results refers to the usable battery capacity, i.e. after a 70% and an 80% of its actual capacity has been deduced in order to meet its cycle and calendar lifetime respectively.

To better comprehend the results, by inspecting the savings (Fig. 5) and LF (Fig. 6) it is possible to distinguish two kinds of responses, a spike like response and slow varying response between the spikes. The spike like response is due to the SOC limit in Off-Peak period reaching 100% and the slow varying response is due to changes in the load clip value (i.e. changes in battery power and capacity). The values were changing according to the different test cases as described in Fig. 4.

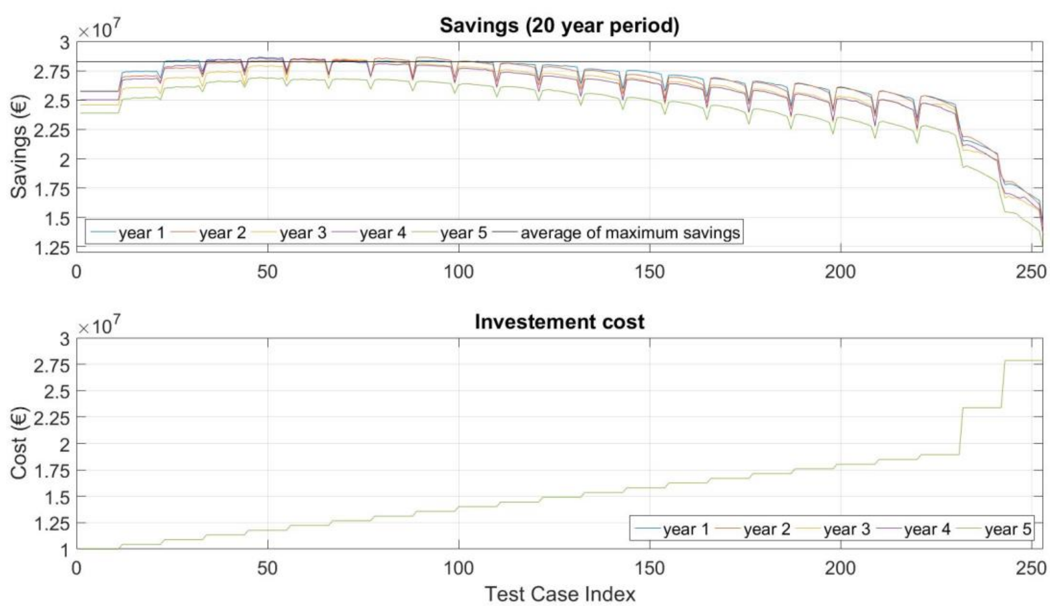

Fig. 5. Savings for a 20 year period and investment cost for 5 consecutive years of PV power data.

By examining Fig. 5, it is seen that the savings are comparable for the 5 years of PV generation and the average of the maximum of each year in a period of 20 years is €28.3 M. In the first test cases, the savings are low because of the inadequate battery size, hence not much PV energy is shifted into the high tariff Peak and Intermediate periods to reduce the energy consumption. In the last test cases, the savings are even lower than the savings with the PV alone due to the high investment cost of the battery. The highest savings occur in test case 45 which has a battery of 1 MW / 1 MWh usable capacity and 0% SOC limit in the Off-Peak period (i.e. the battery is not charged during Off-Peak period). The battery that will be installed in the campus will have an actual capacity of 1 MW / 1.8 MWh due to the lifetime restrictions on SOC and operating temperature of lithium-ion technology. The investment cost starts from €10 M (PV only) and then increases as the battery capacity increases. It is worth to note that the payback period in the optimum test case (case 45) is 6.1 years and the investment cost is €11.8 M.

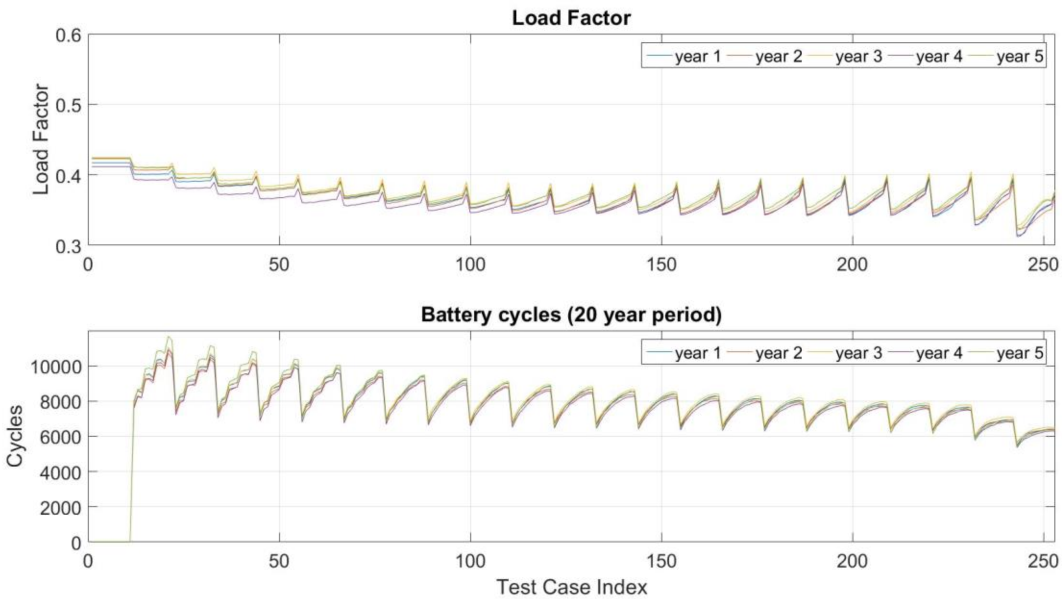

Fig. 6. LF and total battery cycles for 5 consecutive years of PV production data.

The estimated future LF of the University campus load without PV and battery storage is 0.55. From the results in Fig. 6, it can be seen that the LF decreases from 0.55 but it is still within the same LF tariff band of 31% to 60%. Therefore, the future microgrid will not shift the tariffs out of the central LF tariff band. The battery full cycles were calculated in order to assess the lifetime of the battery at the optimum solution and the result shows that with the optimum solution the battery completes approximately 7130 full cycles. This is lower than the maximum number of full cycles a lithium-ion battery can complete before its capacity drops to 70% of the initial value [13].

4.3. Centralised vs Decentralised Battery System Feeder Cable Power Loss

A centralized battery system was compared with a distributed one for the UCY future microgrid. The main focus at this point was the power loss in the cable of the feeders and reliability / flexibility of each system.

From Fig. 7, it is seen that for the case of UCY with a centralised PV plant a centralised battery system has marginally lower energy losses than a decentralised one (difference of 1.5 MWh annually). This difference is due to the power for charging the distributed batteries since the PV plant will be concentrated at a central point and the charging power will have to flow through the cable of the feeders to reach the batteries at each campus substation. Although the energy loss difference is not high, in terms of reliability, a centralised battery system will imply less thermal stress to the cables which is an important factor to consider in the hot climate of Cyprus. In addition a centralised system favours reliability because fewer components are used and the probability of a failure is reduced. In terms of flexibility, a decentralised battery system favours the vision of UCY to become a living test bench for PV and battery storage since each substation with a battery could be isolated and independent experiments can be performed. Therefore, the marginally low energy loss difference allows the University to consider any configuration suits its needs for becoming a living lab.

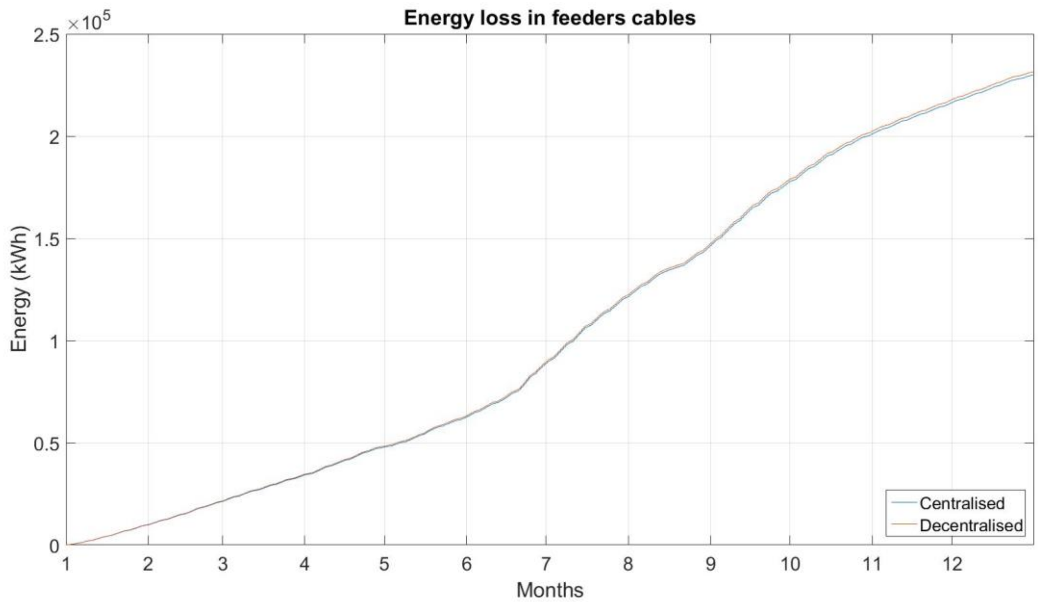

Fig. 7. Energy loss in the UCY campus feeders cable accumulated in a year.

4. Conclusions

The UCY aspires to become a carbon neutral institution through the implementation of a microgrid with a large photovoltaic (PV) plant and battery storage making the whole university a net-zero energy campus. In this paper, a modelling approach was used to calculate the required peak PV power and the optimum battery size (energy and power) in order to reduce the University's electricity bill, which is based on a time of use (ToU) tariff scheme. An energy management algorithm was developed to reduce the energy consumption in expensive tariff periods by performing peak shaving. The battery size was optimised based on this algorithm by multiple runs of battery related parameter combinations to find the most cost-effective solution. The optimisation was done for a lithium-ion battery and it was found that its cycle life time is enough for the system to last for 20 years. In addition, the payback period of the optimum solution (10 MWp PV and a battery of 1 MW / 1 MWh usable capacity or 1 MW / 1.8 MWh actual capacity) was 6.1 years and the total savings in a 20 year period was €28.3 M with an investment cost of €11.8 M. Finally, the power losses in the University's power feeders were compared for a centralised and a decentralised battery system. For this case study with a centralised PV plant, a centralised battery system was found to have marginally lower loss in the cables by only 1.5 MWh in a year compared to a decentralised system, hence any system can be chosen depending on the needs of the University to become a living lab.

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