Economic Viability of Distribution Network Upgrade Deferral through BESS Sizing from K-Means Clustered Annual Load Profile Data

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ABSTRACT

The augmented electricity demand requires electrical infrastructure upgrades with system operators instituting strategies to increase Distribution Network (DN) capacity in tandem with load growth. In this study, a simple method of deploying Li-ion Battery Energy Storage Systems (BESSs) to defer DN upgrades is presented by utilizing historical load profiles. The k-means algorithm is employed to cluster the annual load profiles obtained from a substation in groups of 15-minute intervals. The load data are min-max scaled and fed as input to the K-means algorithm. The NPV financial analysis method is followed in the DN upgrade deferral benefit determination with the acquired benefit depending on Li-ion BESS price and feeder upgrade cost. The results indicate economic viability of up to four years with a Net Present Value (NPV) of US$10k for Li-ion 2000kW/3000kWh BESS. More benefits and deferral years are achieved by varying Li-ion BESS and feeder upgrade costs to 80% and 120%, respectively with deferral years increased to six with an NPV of US$110k for Li-ion BESS of 3100kW/6000kWh.

Keywords-infrastructure upgrade; distribution network; avoided costs; K-means

I. INTRODUCTION

The core role of distribution system planning is to securely satisfy the demand growth from the distribution feeders by connecting the end consumers optimally, with the key objective of minimizing substation and feeders' investment costs while satisfying voltage profile, reliability, loss reduction, and service maintenance constraints. As the peak demand increases, the existing networks becomes congested, and distribution system operators are thus required to upgrade the existing networks. Utilities can ensure this through the use of DG, engaging DSM programs, network upgrades by expansion and/or reinforcement of network infrastructure, or by placing properly sized, sited, and operated ESS in the network.

Traditional capacity upgrade is geared towards meeting forecasted peak loads over the planning horizon resulting in capacity idleness as peak loadings usually occur for a few hours annually. Further, capital intensiveness and longer construction times imply that utilities devote large resources and time for such projects and thereafter transfer costs to consumers impacting negatively the cost of electricity. Non-wire alternatives like energy storage systems are fast being adopted requiring economic analysis due to their relatively high initial capital and maintenance costs.

Regarding Battery Energy Storage Systems (BESSs), Li-ion battery type is preferred due to its increased performance, decreasing cost, fast response, locational flexibility, and suitability in power quality to energy management applications. Lithium Nickel Manganese Cobalt Oxide Chemistry is one of the most popular choices for utility-scale applications owing to its high specific energy 140-200Wh/kg, improved thermal stability, high cycle life, and high round trip efficiency of up to 93-96% [1, 2]. However, high BESS investment costs raise concerns on its economic viability. Before BESS deployment, an assessment is important regarding its economic and technical benefits.

Energy storage systems can be combined with the network's real time thermal ratings for reinforcement deferral [3], load growth related distribution capacity upgrade deferral, network reliability improvement, and congestion management through peak shaving [4-6], energy cost reduction [7]. This combination may also defer distribution feeder upgrade [8] with deferral period and benefit(s) dependent greatly on load growth rate, feeder upgrade, and BESS investment costs. Energy Storage Systems (ESSs) have been applied in deferral of substation expansion [9, 10], with BESS being more economically suitable on MV networks than HV networks and substations.

Load reduction is employed in [11] for Distribution Network (DN) upgrade deferral. The intelligent single particle optimizer was utilized in [12] to allocate Network-Attached Storage (NAS) BESS for grid upgrade deferral and was tested on a modified IEEE 33 – node distribution system. GA optimization of BESS in the presence of wind generator for sub transmission substation upgrade deferral was presented in [13], considering network reliability and economic viability and achieved significant deferral benefit when DG and BESS were combined. PV and ESS deployment was utilized in [14] to defer distribution station transformer upgrades. The NPV method was employed in [15] to quantify the network upgrade deferral benefit value of DG. The authors concluded that deferral benefit depends on upgrade timing. Authors in [16] applied the Particle Swarm Optimization (PSO) algorithm to optimally size lead acid BESS in a grid-connected residential photovoltaic system for cost minimization. The NPV method was followed to evaluate the investment deferral value of microgeneration in EHV DNs in [17] wherein the benefit was depending on microgeneration placement. In [18], the NPV is used to determine the grid reinforcement deferral value through demand side flexibility. The authors conclude that flexibility steering can postpone the short term network expansion investment.

It can be concluded that the benefits of DN upgrade deferral are situational and location dependent. This paper analyses the use of Li-ion BESSs for load growth related DN upgrade deferral by investigating its economic viability

II. METHODOLOGY

A. Distribution Network Upgrade Modeling

As power demand increases, DN's peak load reaches a point at which thermal stresses exceed the recommended static rating. BESSs supply a load portion during the peak time keeping it within the thermal limit as indicated in Figure 1.

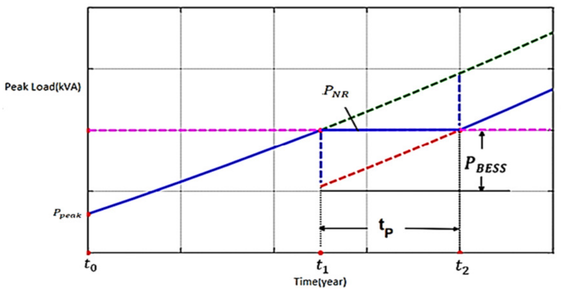

Fig. 1. Peak shaving of peak demand.

If the rated load is P_{NR} and the peak load is P_{peak}, the time t_1 to upgrade the feeder assuming annual load growth rate of l_{gr} is given in (2).

$$P_{NR} = P_{peak}(1 + l_{gr})^{t1} \quad (1)$$

$$t_1 = \frac{logP_{NR} - logP_{peak}}{log(1+l_{gr})} \quad (2)$$

Installing BESS of power capacity P_{BESS}, the upgrade time is increased as per (4) in which t_2 represents the years for the feeder to breach P_{NR} with BESSs and t_1 is the deferral duration.

$$P_{new\_peak} = P_{peak} - P_{BESS} \quad (3)$$

$$t_2 = \frac{logP_{NR} - log(P_{peak} - P_{BESS})}{log(1+l_{gr})} \quad (4)$$

Load growth rate determines the projected load for the future years. Heuristically, the annual load growth rate l_{gr}, is decided as a percentage of the base year peak load and is obtained from actual system actual peak loads as per (7).

$$l_{agr} = \left(\frac{\Delta P_{peak}}{P_{peak-previous\ year}}\right)\% \quad (5)$$

$$l_{agr_n} = \left(\frac{P_{peak_n} - P_{peak_{n-1}}}{P_{peak_n}}\right)\% \quad (6)$$

$$l_{gr} = \frac{1}{N}\sum_{n=1}^{N}\left(\frac{P_{peak_n} - P_{peak_{n-1}}}{P_{peak_n}}\right)\% \quad (7)$$

If the network upgrade cost is C_{tot}, the avoided cost is calculated as per (10), where d is the discount rate.

$$PV_{org} = \frac{C_{tot}}{(1+d)^{t1}} \quad (8)$$

$$PV_{new} = \frac{C_{tot}}{(1+d)^{t2}} \quad (9)$$

$$C_{avoid} = C_{tot}\left(\frac{1}{(1+d)^{t_1}} - \frac{1}{(1+d)^{t_2}}\right) \quad (10)$$

B. BESS Sizing

BESSs must have sufficient power capacity to counterbalance the projected peak load and energy capacity to offset the length of the projected peak load. Twenty four-hour period load data must be utilized to provide valuable analysis for implementing and estimating the size of the storage in end user applications. BESS power capacity P_{bess} and energy capacity E_{bess} are acquired from sizing the load profile.

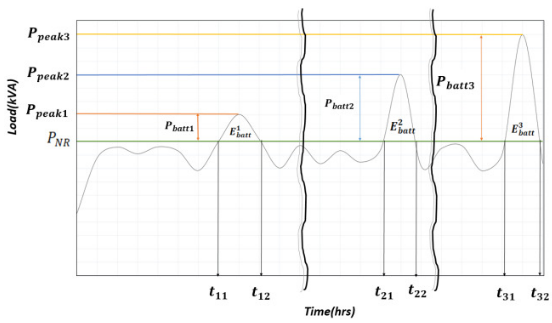

Fig. 2. Illustration of different peak day loads.

The annual load data are first min-max normalized, and all values are transformed in the [0,1] range. If X is a numeric attribute with n observed values, $x_i \geq 0, i = 1, \ldots, n$. A value x_i of X is normalized to $\tilde{x}$ by:

$$\tilde{x}_i = \frac{x_i - x_{min}}{x_{max} - x_{min}} \quad (11)$$

where x_{min} and x_{max} are the minimum and maximum values of the attribute X.

The reviewed literature on power consumption classification in [19] concluded that K-means is a widely applied and prevalent method due to its simplicity and generally satisfactory performance. The proposed approach therefore implements the K-means clustering algorithm. The similarity between two objects (*X* and *Y*) is defined as:

$$d(X,Y) = \sqrt{\sum_{i=1}^{m}(x_i - y_i)^2} \quad (12)$$

Observations are assigned to the k clusters to minimize the average Euclidean distance of the observations from the cluster centroid. The objective of the K-means algorithm is the Euclidean distance minimization as *n* data objects are separated into k clusters [20].

$$min\{d(X,Y)\} = \sum_{j=1}^{k}\sum_{i=1}^{n} ||x_i^{(j)} - c_j||^2 \quad (13)$$

where c_i is the mean value of cluster C_i. The K-means clustering algorithm is summarized in the following steps:

- Choose k initial centers $(c_1, c_2, , , , , , c_k)$
- Assign each data object $x_i^{(j)}$ to its nearest cluster center c_j
- Obtain the mean of all $x_i^{(j)}$ to update each cluster center c_j
- Repeat the last two steps until no further change is found in cluster centers.

The profile within a cluster C_i is determined by two steps. At first, the data corresponding to the same hourly intervals are summed up. In the second step, the average hourly load profile is calculated to obtain the cluster centroids by:

$$P_{mh}(i) = \frac{\sum_{j=1}^{N}\left(P_j(i)\right)}{N} \quad (14)$$

where P_{mh} is the average power at the i^{th} hour, j is the day and *N* is the total number of profiles in the cluster.

One of the obtained clusters, would have the maximum electricity consumption:

$$C_{peak} = \{C_j | max_{j=1:n_c, i=1:T}\left(dCEN_j^i\right), \forall C_j \epsilon \Omega \quad (15)$$

BESS size of the load profile LP_s, has the maximum discharge duration and is thus an outlier in C_{peak}:

$$LP_s = \{LP \epsilon C_{peak} | max_{LP=1:n_1}\left(N_{disch}(LP)\right) \& LOF(LP) > 1\} \quad (16)$$

The sizing load profile LP_s^n during the year of interest n is estimated as:

$$LP_s^n = LP_s^b(1 + l_{gr}) \quad (17)$$

E_{batt} for the sizing load profile LP_s is determined by the area between the sizing load profile curve and the line for reference upstream grid demand P_{NR} as:

$$P_{batt} = P_{peak} - P_{NR} \quad (18)$$

$$E_{batt} = \int_{t1}^{t2}\left(P_{cpeak}(t) - P_{NR}(t)\right)dt \quad (19)$$

P_{bess} and E_{bess} are obtained by taking into account the optimization constraints within the discharge duration given by (22):

$$P_{bess} = \frac{P_{batt}}{\eta_{pcs}} \quad (20)$$

$$E_{bess} = E_{batt}\left(\frac{1}{\eta_{disch}} + SoC_{min}\right) \quad (21)$$

$$t = \frac{E_{bess}}{P_{bess}} \quad (22)$$

Conductor thermal rating P_{NR} is obtained from its resistance and surface heat dissipation [21]:

$$I = \sqrt{\left(\frac{S}{R}\left(\frac{\Delta t(0.0128\sqrt{pv})}{T_{air}^{0.123}\sqrt{d_{cond}}} + 36.8E\left(\frac{T_c^4 - T_{air}^4}{1000^4}\right)\right)\right)}(A) \quad (23)$$

where I is the current carrying capacity (A), S is the surface area (sq. in), R is the resistance (Ω), p is the atmospheric pressure (atm), v is the wind velocity (ft/s), d_{cond} is the conductor diameter (in), T_{air} is the air temperature (K), T_c is the conductor temperature (°C), $\Delta t = T_c - T_{air}$ is the temperature rise of the conductor (°C), E is the emissivity constant, and V_{LL} represents the line to line voltage.

C. The Objective function

Utility owned BESS investment cost minimization is the main objective of the current study with the optimization problem given as:

$$f = min(C_{bess}) \quad (24)$$

The BESS investment cost C_{bess} is a summation of the capital cost C_{cap}, the operation and maintenance cost $C_{o\&m}$, the replacement cost C_{rep}, and the disposal cost C_{disp} during the deferral period t_p.

$$C_{bess} = C_{cap}(C_{POW}, C_{EN}) + C_{o\&m} + C_{rep} + C_{disp} \quad (25)$$

The cost's present value during the deferral period is evaluated using the discounted factor F_{pv}:

$$F_{pv} = \left(\frac{(1+\alpha)}{(1+d)^{t-1}}\right) \quad (26)$$

where α is the cost rate of change.

The economic value of the network upgrade deferral NPV_{value}, over the planning horizon *n* = 15, is determined by:

$$NPV_{value} = PVC_{tot} - \left(PVC_{bess} + \frac{PVC_{tot}}{(1+d)^{t_p}}\right) \quad (27)$$

where PVC_{bess} is calculated over t_p years assuming zero replacement and disposal during the deferral duration.

$$PVC_{bess} = \sum_{t=1}^{t_p}\left(\frac{C_{o\&m}}{(1+d)^t} + C_{CAP}\right) \quad (28)$$

For economic viability, (29) must be satisfied.

$$PVC_{tot} - \frac{PVC_{tot}}{(1+d)^{t_p}} \geq PVC_{bess} \quad (29)$$

The flowchart of the NPV economic viability methodology is summarized in Figure 3.

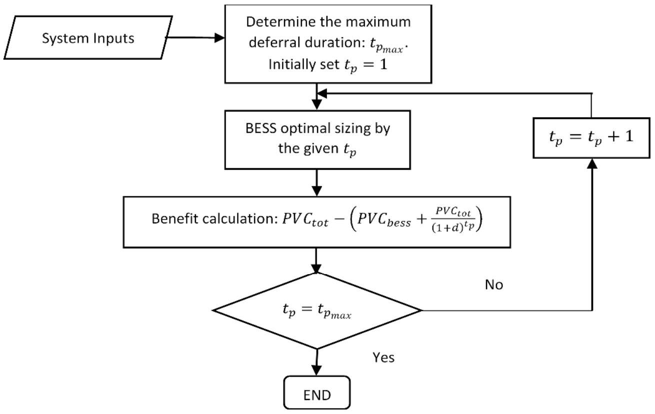

Fig. 3. Economic and deferral analysis flowchart.

III. CASE STUDY

Real time active power load data employed in the sizing of BESS for distribution network upgrade deferral were carried out using practical field demand data obtained online [22] for the Adaminaby 33/11kV substation located in Cooma Region, New South Wales, Australia for an one-year period, from 10/1/2021 to 9/30/2022, accessed on July 2022. The peak demand was 1300 kW occurring on 7/11/2022 at 19:30:00.

IV. RESULTS AND DISCUSSION

The results obtained for two different developed investment scenarios, i.e. the use of BESS and traditional distribution network construction are presented in this section. MATLAB was utilized for analysis, carrying out the K-means algorithm, and curve fitting.

A. Sizing Load Profile - LP_s

The hourly active load data from the Adamaniby 11 kV substation were implemented. Raw annual data for the period analyzed are represented in Figure 4 with daily 24-hr load profiles depicted in Figure 5. Some abnormal behavior of the load patterns may occur unexpectedly due to special occasions, called outliers. Raw daily load profile data were thus cleaned by removing time series with zero power recorded and with missing values. Thereafter, min-max scaler normalization was conducted ensuring that the clustering of data is based on pattern shape and not on usage magnitude. The result is plotted in Figures 6 and 7.

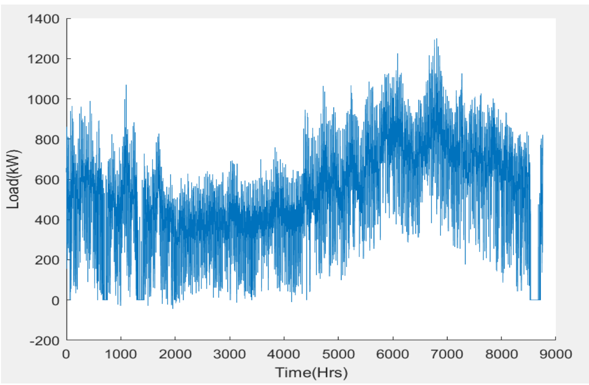

Fig. 4. Substation historical raw annual load profile.

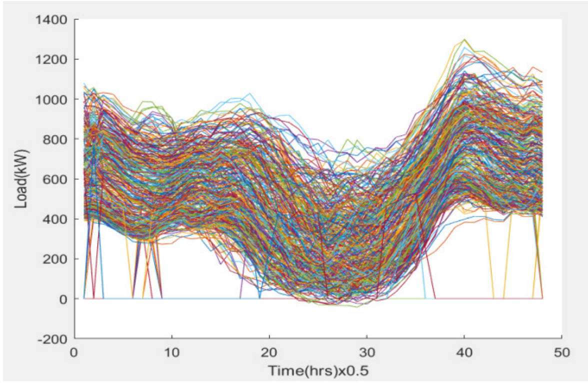

Fig. 5. Substation historical raw daily load profiles.

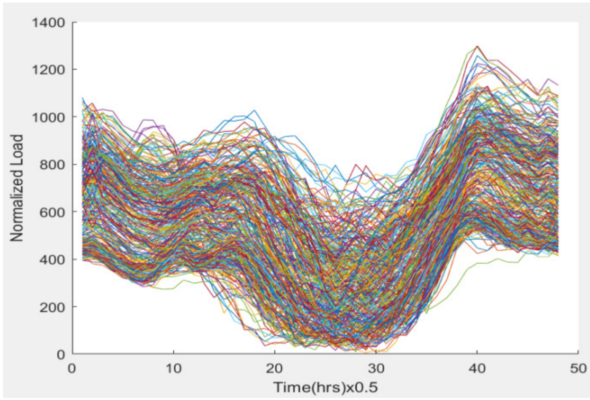

Fig. 6. Non-zero daily load profiles.

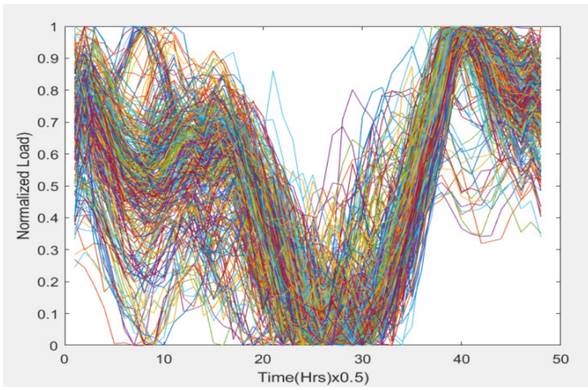

Fig. 7. Min-max normalized daily load profiles.

The min-max normalized load profiles were fed as input to the K-means clustering algorithm with the Calinski-Harabasz criterion method utilized to evaluate the optimal number of clusters. The plot shows that the highest Calinski-Harabasz value occurs at k=3, indicating the optimal number of clusters as three. The resultant clusters are portrayed in Figure 9. Cluster one has 22 variables, cluster two has 75 variables, and cluster three has 226 variables with clusters and cluster centroids depicted in Figures 10-12.

In cluster k=2, a large electricity consumption is noted. This is the BESS sizing load profile $LP_{S,}$ upon which BESS sizing is undertaken.

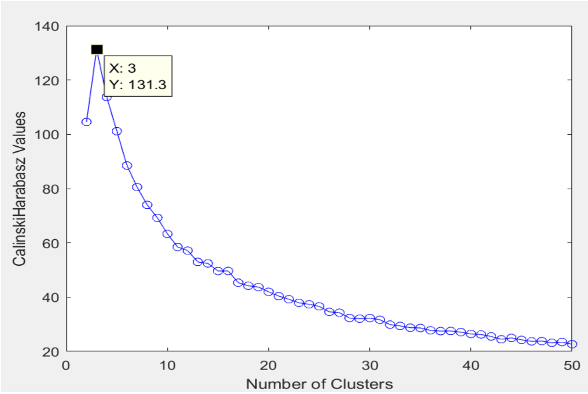

Fig. 8. Calinski-Harabasz criterion showing the optimal *k*.

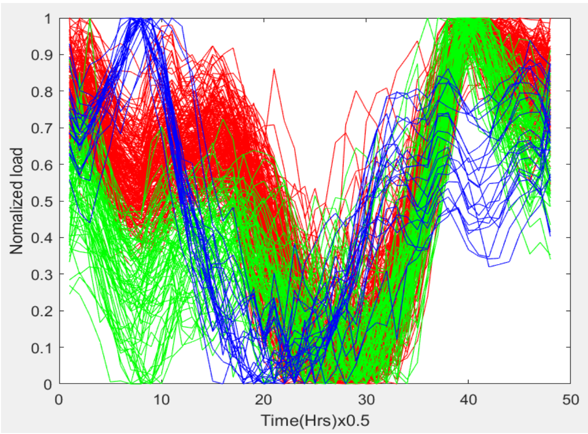

Fig. 9. Illustration of the three clusters.

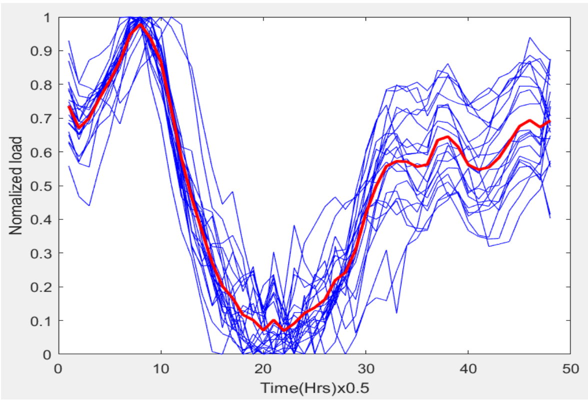

Fig. 10. Cluster#1 and cluster centroid profile.

B. BESS size

Considering an actual time variation, BESS sizing load profile LP_s was extrapolated for each year with a constant load growth rate of l_{gr} = 4.55% modeled as a homothetic growth in all distribution load nodes, in the 15-year project lifetime (n = 15). MATLAB code was deployed in sizing, with BESS P_{bess} and E_{bess} determined over the planning period from t_0= 1 to t_{15} = 15. The obtained results are fitted with the Fitting Curve Tool of MATLAB and are illustrated in Figure 13.

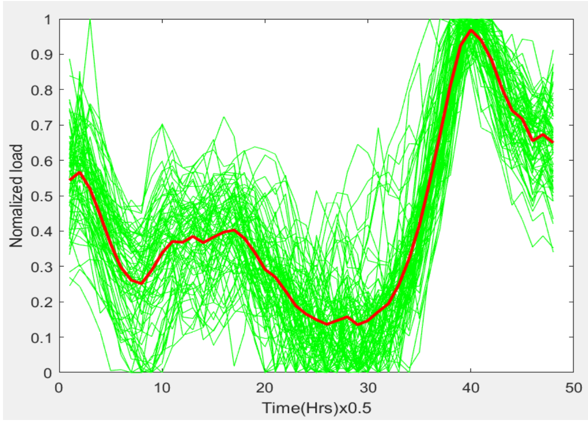

Fig. 11. Cluster#2 and cluster centroid profile.

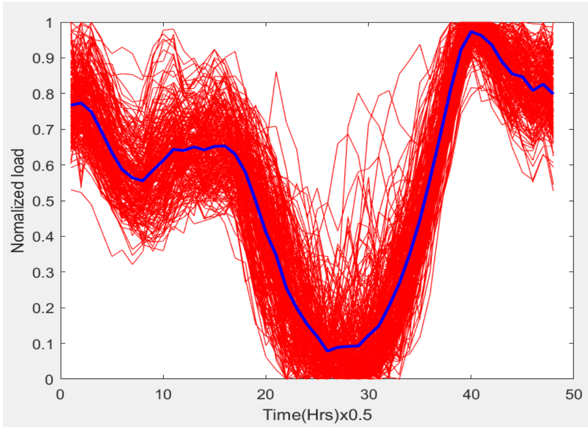

Fig. 12. Cluster#3 and cluster centroid profile.

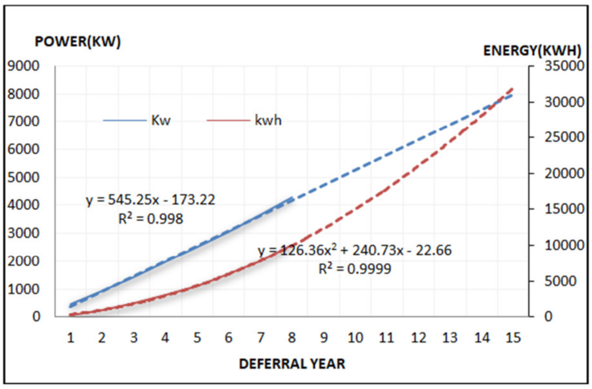

Fig. 13. BESS size to defer network upgrade.

C. Economic Analysis

Applying the assumptions of Table I, the NPV from the economic analysis is presented. It is assumed that BESS capacity will stay at nominal value until replacement and the performance per kW of DN and BESS are equal, i.e. each kW of the discharge capability from BESS storage can defer one kW of the distribution load. Also, the upgraded network is expected to serve for 15 years.

TABLE I. ASSUMPTIONS

Variable	Parameter	Unit	Value
η_{ch}, η_{disch}	Charging and discharging efficiency	%	90
$Soc_{(min,max)}$	Usable SoC	%	5-95
$Batt_{cyc-life}$	BESS life cycle	FEC	15years
η_{inv}	Efficiency	%	97.5
T_{inv}	Inverter lifetime	Years	20
C_{POW}	BESS power cost	US$/kW	250
C_{EN}	BESS energy cost	US$/kWh	326
DNU construction cost		US$/km	100,000
d	Discount rate	%	10
$C_{o\&m}$	BESS operation and maintenance cost	6% of C_{CAP}	
Planning horizon		15years	

The deferral benefit equaling cost of the avoided network upgrade is positive up to the fourth year of deferral, beyond which, the use of the Li-ion BESS at the prevailing costs and at the existing cost of feeder upgrade per km, becomes unviable as shown in Figure 14. This implies the utility must expand the distribution network through the construction of additional feeders or use higher rated feeder in place of the existing network.

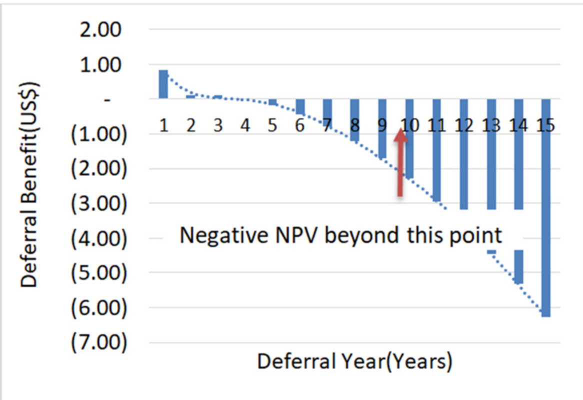

Fig. 14. NPV over the 15-year planning horizon.

By varying the BESS capital costs from 80 to 100% and feeder upgrade costs feeder from 100 to 120%, the sensitivity of the objective function is analyzed and the results are graphically represented in Figure 15.

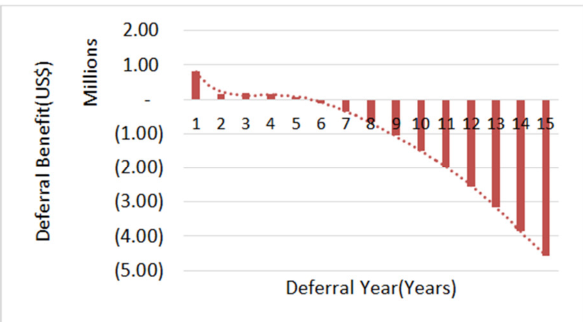

Fig. 15. NPV 80% C_{bess} and 100% C_{tot} over the 15-year planning horizon.

With BESS capital costs reduced to 80% and feeder upgrade costs increased to 120% of the current prices, more deferral years, and by extension benefits, are obtained in all scenarios within the 15 year planning horizon (Figure 16). The effective deferral years is t_p = 5 with a benefit of US$60k for a BESS sized 2600kW/4300kWh. With BESS capital costs reduced to 80% and feeder upgrade costs increased to 120%, more deferral years, and by extension benefits, are obtained in all scenarios within the 15 year planning horizon. The effective deferral years is t_p = 6 with a benefit of US$110k for a BESS sized 3100kW/6000kWh (Figure 17).

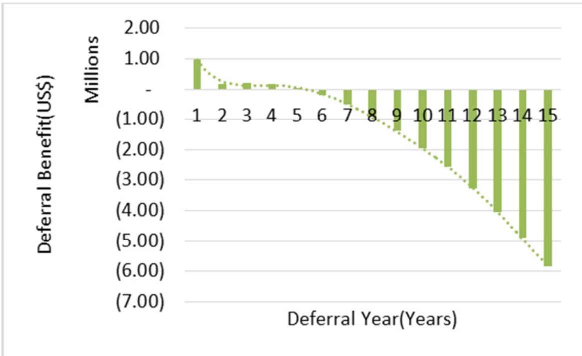

Fig. 16. NPV 100% C_{bess} and 120% C_{tot} over the 15-year planning horizon.

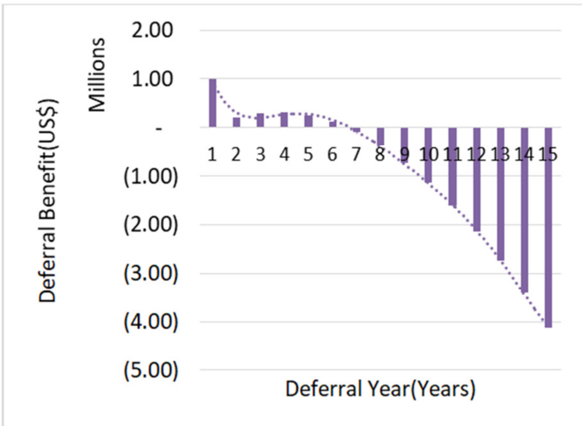

Fig. 17. NPV 80% C_{bess} and 120% C_{tot} over the 15-year planning horizon.

Increasing the distribution network rating results to reduced deferral years, and by extension, benefits. Equally, from the case study, BESS deployment for distribution network upgrade deferral is viable for 4 years with NPV of US$10k for BESS sized 2000kW/3000kWh. Economic viability depends on BESS capital costs and feeder upgrade length per km. Varying BESS capital cost and feeder upgrade cost results to deferral benefit change. Figure 18 presents the impacts of the cost changes on the deferral value.

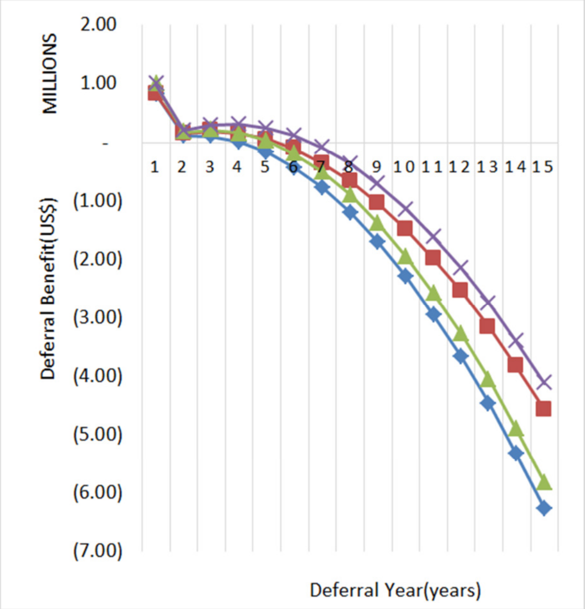

Fig. 18. Impacts of cost changes on the deferral value for the 15-year deferral period.

V. CONCLUSION

With the emergence of energy storage technologies in various markets, their incorporation into existing and or newer installations is bound to happen. Therefore, the issue of their financial suitability arises. This paper compares two upgrade options available to distribution network operators in responding to load growth related infrastructure capacity upgrades, namely expansion of feeders and associated laterals, and the incorporation of Li-ion BESSs. A simple methodology utilizing K-means algorithm was followed to cluster one year of daily load data and NPV was used for financial analysis. This paper has demonstrated that load growth related distribution network infrastructure capacity upgrades may be deferred through the deployment of NMC Li-ion BESSs with the benefits and duration of such deferral depending on the energy storage system and the upgrade costs. A simple methodology for energy storage economic viability investigation was provided, devoid of complex mathematical and heuristic algorithms, while still giving a satisfactory analysis. This can be easily replicated in other project economic viability studies. Future research can explore the utility of other ESS technologies and value stacking BESSs for optimal economic potential maximization through the hierarchical prioritization of services.

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