



(RESEARCH ARTICLE)



OPERATIONAL IMPACT ASSESSMENT OF ROOFTOP SOLAR PV AND BATTERY ENERGY STORAGE INTEGRATION ON A 22 KV URBAN DISTRIBUTION FEEDER IN DA NANG CITY, VIETNAM

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ABSTRACT

The rapid growth of rooftop solar photovoltaic (PV) systems is turning urban distribution feeders from passive, unidirectional circuits into active networks with variable and bidirectional power flows. This paper assesses the operational impact of rooftop PV and battery energy storage systems (BESS) on a real 22 kV urban feeder (outgoing feeder 480 of the 110 kV ADO substation) in Da Nang City, Vietnam. A network model with 17 medium-voltage nodes and 49 monitored 0.4 kV busbars was built in DigSILENT PowerFactory from utility network data and measured PV and load profiles. Newton–Raphson load-flow studies (11:00, 20:00 and 24-hour profiles) and RMS simulations of cloud-cover and thunderstorm events, with PV represented as constant-power static generators, were carried out for the existing network, for a doubled-PV scenario with distributed BESS and for a load-levelling BESS. With 1.9 MWp of existing rooftop PV (about 16% of the feeder peak) all voltages stay within $\pm 5\%$ of nominal (maximum 1.045 p.u. at the substation bus, 1.026 p.u. at 0.4 kV). The simulated events cause voltage steps of about 0.001 p.u. and short spikes in the local bus-frequency signal (minimum 49.816 Hz; 49.805 Hz with PV doubled); because inverter controls and upstream-grid dynamics are not modelled, this signal is used only as a relative screening indicator and not as a system-frequency result. Doubling the PV capacity to 3.8 MWp with distributed BESS reduces the noon active-power loss by 28% and the daily energy loss by 11.5%. A partial-deployment load-levelling dispatch of 0.62 MW (about 11% of the 5.6 MW / 11.7 MWh design) lowers the evening peak by 5.1%, raises the night valley by 8.1% and cuts active and reactive losses at 20:00 by 21% and 19%; the full design is assessed only economically. A 20-year cash-flow model of the 11.7 MWh BESS gives NPV $\approx$ VND 113 billion, IRR $\approx$ 21.8% and a discounted payback of about 6 years under the assumed tariffs, but NPV falls to VND 28 billion if the peak price is 40% lower and to VND 56 billion without tariff escalation, and it is close to zero under combined adverse assumptions, so the economic result is preliminary. The results provide quantitative guidance for utilities planning PV hosting and storage deployment on urban 22 kV feeders.

Keywords: Rooftop Solar PV; Battery Energy Storage System (BESS); Distribution Network; Load Flow; Voltage Profile; Power Loss; Peak Shaving; Digsilent Powerfactory

1 INTRODUCTION

Vietnam's power sector is moving quickly towards renewable energy. The revised National Power Development Plan VIII (PDP8) targets 46,459–73,416 MW of solar power and 10,000–16,300 MW of battery storage by 2030 [1], and

distributed rooftop solar is expected to carry a growing share of this build-out. In Da Nang City, a fast-growing urban centre with good solar resource, grid-connected rooftop PV has expanded rapidly in recent years. Most of these systems connect at 0.4 kV or 22 kV on urban feeders that were planned for one-way power flow from the substation to the load.

At high penetration, distributed PV changes how such feeders behave. Local generation raises voltage along the feeder, can reverse the power flow, changes losses and loading, and makes network operation more dependent on weather because PV output can drop quickly when clouds pass [2–4]. Conversely, after sunset the feeder is stressed by the evening demand peak with no PV support. Battery energy storage systems (BESS) are a flexible way to address both problems: they can absorb surplus midday energy, discharge during the evening peak, support voltage and reduce losses [3]. Utilities therefore need feeder-level evidence of how much PV a given feeder can accept, what happens in weather-driven events, and whether storage is technically and economically justified.

Studies of PV impacts and BESS integration are plentiful [2–4, 11–18], but many rely on standard test feeders, synthetic profiles or generic networks. Fewer combine, for an operating Vietnamese urban 22 kV feeder, (i) measured PV and load profiles, (ii) steady-state and dynamic assessment against the limits of the national grid code [5], (iii) a PV-expansion scenario with storage, and (iv) a financial evaluation of a utility-owned BESS with its sensitivity. This paper addresses that gap for feeder 480 of the 110 kV ADO substation in Da Nang City; Section 1.1 states precisely what is, and is not, new.

The contributions are as follows. First, a PowerFactory model of a real urban feeder is described, together with its PV sites and measured profiles. Second, the effects of existing PV and of weather events on voltage and losses are quantified against the limits of Circular 05/2025/TT-BCT [5], and the limits of the dynamic model are stated. Third, the benefit of doubling PV capacity with distributed BESS and of a load-levelling BESS is quantified, with a transparent sizing procedure and an explicit separation between the design case and the cases actually simulated. Fourth, a 20-year cash-flow analysis of the storage investment is presented in full, together with a sensitivity analysis.

1.1 Related work and novelty

Table 1 compares this paper with nine related studies chosen because they address distribution-network PV, storage, dynamics or economics, including recent Vietnamese work. The classification is the authors' reading of the scope stated in each paper.

Table 1: Comparison with related studies

Study	Network and data	Method	Dynamic	PV + BESS	Siting / sizing	Economics
Nick et al. 2014 [11]	IEEE 34-bus test feeder	Convex AC optimal power flow	–	○	●	●
Mateo et al. 2016 [12]	Three large MV reference networks (urban, semi-urban, rural)	Reference-network model; cost-benefit	–	○	○	●
Regassa 2017 [14]	Utility feeder (PowerFactory); IEEE 13-node (Simulink)	Voltage and frequency studies; Volt-VAr, Frequency-Watt	●	●	–	–
Vu & Nguyen 2024 [15]	Typical Vietnamese urban LV network	Simulink time-domain; power quality	○	○	–	–
Vu et al. 2024 [16]	Typical radial Vietnamese urban grid	PV level and location; losses	–	○	○	–
Tran et al. 2024 [17]	Households in Vietnamese cities (no network)	Metaheuristic sizing of rooftop PV	–	○	●	●
Vu et al. 2026 [18]	Customer-side PV-battery, Vietnamese climate and tariff	Simulation with energy management; TOU	○	●	○	●
Stecca et al. 2020 [3]	Review: BESS in distribution networks	Literature review	n/a	n/a	n/a	n/a

Wong et al. 2019 [13]	Review: ESS placement, sizing, control	Literature review	n/a	n/a	n/a	n/a
This paper	Real 22 kV feeder, Da Nang; measured PV and load	Load flow; RMS without inverter control; cash flow with sensitivity	○	●	–	●

Dynamic: ○ = RMS or time-domain simulation of events, without a full inverter and upstream-grid model. PV + BESS: ● = PV and storage studied together; ○ = only one of them, or storage for another purpose. (● addressed; ○ partly; – not addressed; n/a not applicable).

Table 1 shows what this paper is not. It does not propose a new method: load flow, RMS simulation and discounted cash flow are standard. Its dynamic model is simpler than that of [14], it does not optimise the siting or size of the storage as in [11], and its economic model is less detailed than the cost-benefit study of [12], which also counts avoided reinforcement. The novelty claimed is therefore limited to the following. (i) *Data and application*: one operating Vietnamese 22 kV feeder with measured PV and load profiles is assessed against the limits of Circular 05/2025/TT-BCT, whereas the Vietnamese studies in Table 1 use typical networks or customer-side systems. (ii) *Combination of scenarios*: existing PV, weather events, PV expansion with distributed BESS and a load-levelling BESS are evaluated consistently on the same model and the same data, so that the technical and economic parts can be read together. (iii) *Transparency*: the design case, the simulated cases and the cash flow are reported separately and in full (Table 6, Table 8), with a sensitivity analysis, which allows the reader to judge how far the technical results support the economic ones. (iv) *Application result*: on this feeder the evening demand peak, not the noon PV peak, is the binding condition, so storage on such feeders is justified by peak and loss relief rather than by voltage control. Using a single real feeder is a strength for realism but does not by itself establish generality.

2 MATERIALS AND METHODS

2.1 Study feeder and data

Da Nang's medium-voltage network operates at 22 kV, mainly as open-loop circuits fed from 110 kV substations; the distribution company runs SCADA and distribution automation on the 22 kV level. The study feeder is the 22 kV outgoing feeder 480 of the 110 kV ADO substation. Network topology, conductor types and lengths, and transformer data were obtained from Da Nang Power Company (PC Da Nang) and the Central Power Corporation (EVNCPC). The model, built in DlgSILENT PowerFactory [10], contains 17 medium-voltage nodes and 49 monitored 0.4 kV busbars supplying industrial and commercial customers (including seafood-processing and wastewater-treatment facilities).

Six rooftop PV plants with a total installed capacity of 1.9 MWp are connected (Table 2). Their output follows a normalised profile measured in Da Nang in June at 30-minute resolution between 06:00 and 17:30 (Figure 2a); at 11:00 the plants deliver 73% of their rated power, i.e. 1.39 MW in total. The feeder load profile at the substation (Figure 2b) was taken from 30-minute substation measurements: the minimum is 6.39 MW (05:00), the evening peak is 12.12 MW (20:00) and the daily energy is 221.0 MWh. PV therefore represents about 16% of the feeder peak (installed basis) and 15% of the 11:00 load (output basis).

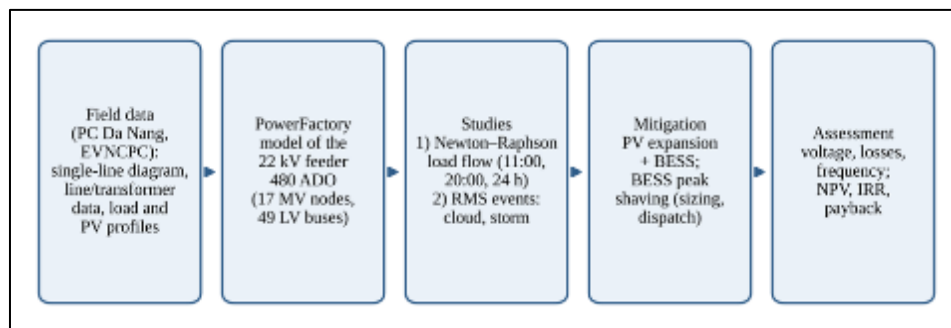
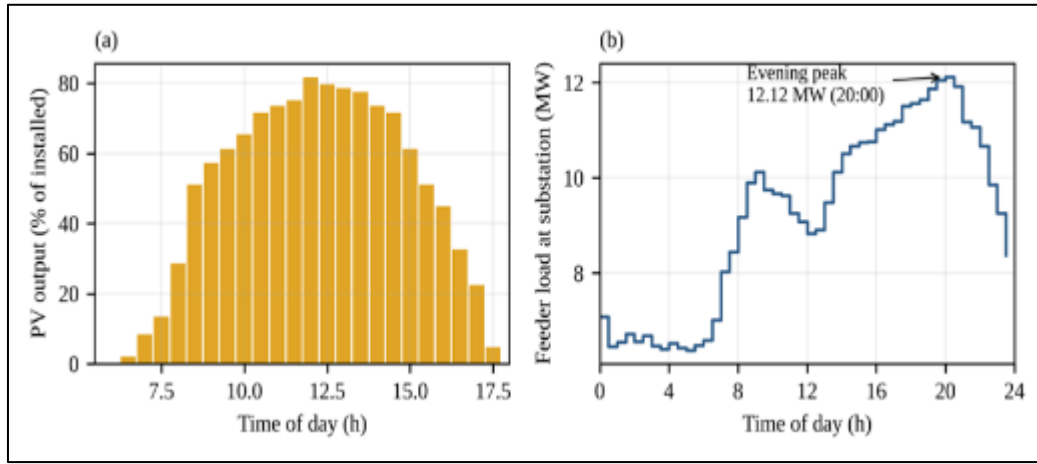


Figure 1: Workflow of the study.

Table 2: Existing rooftop PV plants on the feeder at 11:00 (measured June profile).

No.	Rooftop PV plant	Installed (MWp)	Output at 11:00 (MW)
1	Thien Ma	0.320	0.2336
2	Hakawa Co.	0.279	0.2037
3	Nam Cuong Co.	0.511	0.3730
4	Duy Thinh T3	0.200	0.1460
5	Sang Ngoc T2	0.290	0.2117
6	Duy Thinh T4	0.300	0.2190
	Total	1.900	1.387

**Figure 2: Input profiles: (a) normalised PV output (June measurement, 30-min resolution); (b) feeder load at the ADO substation over 24 h.**

2.2 Network and component models

2.2.1 Load flow

Steady-state operation was computed with the Newton–Raphson method [6], which is the standard choice for distribution networks [8] with several generation points and bidirectional flows because of its quadratic convergence. At each iteration the power mismatches

$$\Delta P_i = P_i^{sch} - \sum_k |V_i| |V_k| (G_{ik} \cos \theta_{ik} + B_{ik} \sin \theta_{ik}) \quad (1)$$

$$\Delta Q_i = Q_i^{sch} - \sum_k |V_i| |V_k| (G_{ik} \sin \theta_{ik} - B_{ik} \cos \theta_{ik}) \quad (2)$$

are solved for the voltage-angle and magnitude corrections using the Jacobian matrix, where P_i^{sch} and Q_i^{sch} are the scheduled injections at node i , V the voltage magnitude, θ_{ik} the angle difference, and G_{ik} , B_{ik} the elements of the bus admittance matrix.

2.2.2 PV generation

PV arrays are described by the single-diode model [7]:

$$I = I_{ph} - I_0 \left[\exp \left(\frac{V + IR_s}{nV_t} \right) - 1 \right] - \frac{V + IR_s}{R_{sh}} \quad (3)$$

$$I_{ph} = [I_{sc,ref} + \alpha (T - T_{ref})] \frac{G}{G_{ref}} \quad (4)$$

where I_{ph} is the photocurrent, I_0 the diode saturation current, R_s and R_{sh} the series and shunt resistances, n the ideality factor, $V_t = kT/q$ the thermal voltage, G the irradiance ($G_{ref} = 1000 \text{ W/m}^2$), T the cell temperature ($T_{ref} = 25 \text{ }^\circ\text{C}$) and α the

temperature coefficient of the short-circuit current. In the feeder studies each plant is represented as an inverter-interfaced source whose active power follows the measured profile of Figure 2a, operating at unity power factor ($\cos \varphi = 1$). Voltage-support functions of smart inverters (Volt-VAr, Volt-Watt [9]) were not modelled; as these functions would limit the voltage rise at PV buses, the voltage results presented here can be regarded as conservative.

2.2.3 Network loss

Active and reactive power losses are taken from the load-flow results as the sum of branch losses, $P_{\text{loss}} = \sum R_b I_b^2$ and $Q_{\text{loss}} = \sum X_b I_b^2$. The relative reduction of a loss measure x between a base case 0 and a scenario 1 is $\eta_x = (x_0 - x_1)/x_0 \times 100\%$. Daily energy losses are obtained by integrating the 48 half-hourly values.

2.3 Operating limits

Results are assessed against Circular 05/2025/TT-BCT of the Ministry of Industry and Trade [5]. In normal operation the voltage at connection points must remain within $\pm 5\%$ of nominal for customers and between $+10\%$ and -5% for power plants. The system frequency may vary within ± 0.2 Hz around 50 Hz in normal operation, and between 49 Hz and 51 Hz after a single contingency. These frequency limits refer to the system frequency of the interconnected grid; Section 2.4 explains how they are used for the local bus signal of the RMS model.

2.4 Dynamic (RMS) simulation model

The weather events of scenarios S2 and S3 were simulated in the PowerFactory RMS domain (balanced, positive sequence). Table 3 lists what the model contains and what it does not. The purpose is to show how feeder voltages respond to a sudden loss of PV output and to compare scenarios, not to study the frequency stability of the interconnected power system.

Table 3: Dynamic simulation model and its limits.

Item	Representation in this study
Simulation	RMS, balanced positive sequence; simulated time (stop time) 30 s; events at 10 s and 20 s
Initial condition	Newton–Raphson load flow at 11:00 (PV at 73% of rated power, load of 11:00); quantities constant until the first event
PV plants	Static generators with constant P (value at 11:00) and $Q = 0$ ($\cos \varphi = 1$). Loss of output is a step to $P = 0$ (restored by a step at 20 s in the cloud case). No inverter model, MPPT, DC link, PLL, current limit, ride-through or frequency–power control
BESS (S3)	Static generators with fixed set-points (Table 5); no state of charge, converter control or virtual inertia
Loads and upstream grid	Loads: active and reactive power at the 11:00 values. Upstream network: the 110 kV ADO substation is represented by an external grid (slack source; no inertia, no governor)
Frequency signal	PowerFactory bus “Electrical Frequency” output: a local signal at each monitored bus, derived from the rate of change of the bus voltage angle; not a centre-of-inertia frequency
Assessment	Voltage steps against the $\pm 5\%$ band; frequency signal against the ± 0.2 Hz band as a screening reference only

The ± 0.2 Hz band of Circular 05/2025/TT-BCT [5] is the normal-operation band of the system frequency. Because the 110 kV network is represented by an external grid, i.e. a stiff source without inertia or governor, the system frequency cannot change in this model; the bus-frequency signal can only show the local transient of the voltage angle caused by the step in injected power. The band is therefore applied only as a screening reference: the PV power lost in one step (1.4 MW at most for the existing plants, about 2.8 MW when the PV is doubled) is small compared with the generation of the interconnected system, so a real system-frequency effect would be negligible. A value inside the band is read as “no concern”; a value near or beyond it would prompt a dynamic study with upstream-grid dynamics, not prove a violation. Because inverter controls and upstream-grid dynamics are not modelled, no conclusion on system-frequency stability is drawn from these results.

2.5 Scenarios

Four groups of studies were carried out (Table 4). (S1) *Base case*: load flow at 11:00 (PV peak) and 20:00 (load peak) and over 24 h. (S2) *Weather events*: RMS simulations over 30 s in which (a) a cloud removes 100% of the output of the Nam Cuong plant between 10 s and 20 s, and (b) a thunderstorm removes the output of three plants (Nam Cuong,

Hakawa, Thien Ma) at 10 s and of all plants at 20 s. (S3) *PV expansion with BESS*: six further rooftop plants (1.9 MWp in total, i.e. doubling the PV capacity to 3.8 MWp, equivalent to about 30% of the 11:00 load) with BESS at three of them (Table 5), reflecting the growth foreseen over the next four years; the same weather event is repeated. (S4) *Load-levelling BESS*: BESS charging at night and discharging during the evening peak; the load-flow study uses the partial dispatch of Case P and the full design (Case D) is evaluated only economically (Section 2.6, Table 6).

Table 4: Summary of the study scenarios.

Scenario	Description	Analysis
S1 Base	Existing PV (1.9 MWp), existing load	Load flow: 11:00, 20:00, 24 h
S2a Cloud	Nam Cuong plant: 100% loss, 10–20 s	RMS, 30 s
S2b Storm	3 plants lost at 10 s; all plants at 20 s	RMS, 30 s
S3 PV + BESS	PV 3.8 MWp; BESS at three plants (Table 5)	Load flow 11:00, 24 h; RMS storm
S4 Load levelling	Night charge, evening discharge: Case P in load flow, Case D in cash flow (Table 6)	Load flow 20:00, 24 h; cash flow

Table 5: PV plants and BESS added in scenario S3.

No.	Site	PV installed (MWp)	Output at 11:00 (MW)	BESS rating (MW)	Charge/discharge (MW)
1	Thai An T2	0.3	0.219	0	0
2	Thuan Phuoc T1	0.4	0.292	0	0
3	Product display centre	0.2	0.146	0	0
4	Tin Vu T3	0.4	0.292	0.33	0.3
5	Thanh Toan	0.3	0.219	0.22	0.2
6	Nam Cuong Co. (second plant)	0.3	0.219	0.22	0.2

2.6 BESS sizing and operating cases

For scenario S4 the BESS is sized to cut the evening peak down to a target power P_{target} and to recharge at night. The energy that must be delivered is the area of the load curve above the target,

$$E_{\text{net}} = \int_{t_1}^{t_2} \max[P_L(t) - P_{\text{target}}, 0] dt \quad (5)$$

and the installed energy follows from the usable depth-of-discharge window, $E_{\text{BESS}} = E_{\text{net}}/k_u$, where $k_u = 0.8$ accounts for operating the cells between 10% and 90% state of charge to preserve life. To avoid reverse power flow the discharge power at a bus must never exceed the local demand,

$$P_{\text{BESS}}^{\text{dis}}(t) \leq P_{L,\text{local}}(t) \quad (6)$$

For the evening period 17:30–22:30 with $P_{\text{target}} = 9.9$ MW, integration of the half-hourly substation load gives $E_{\text{net}} \approx 9.4$ MWh and hence $E_{\text{BESS}} \approx 11.7$ MWh. This is provided by three containerised LiFePO₄ units of 3.9 MWh and 1.875 MW each (15 packs of 261 kWh/125 kW; Table 7), placed at three distribution substations near the end of the feeder (Thuan Phuoc T1 1,000 kVA, XN Son Tra 1,000 kVA and Thai An 1,250 kVA): 45 packs, i.e. 11.7 MWh and 5.6 MW in total. This is the *design case* (Case D).

Consistency of power, energy, duration and state of charge. The usable energy per day is $0.8 \times 11.7 = 9.36$ MWh, which agrees with $E_{\text{net}} \approx 9.4$ MWh. Discharging it over the 5 h peak window needs a mean power of 1.87 MW (33% of the 5.6 MW rating), while the highest power needed for the shaving target is $12.12 - 9.9 = 2.2$ MW, about 40% of the rating. Recharging $9.36/0.90 = 10.4$ MWh within the 6 h off-peak window (00:00–06:00) needs 1.73 MW on average. The

energy-to-power ratio of the installation is $11.7/5.6 = 2.1$ h, so the duty (5 h at 1.87 MW) is energy-limited, not power-limited; the surplus power rating is headroom that the shaving duty does not use. The state of charge moves 90% → 10% during the peak and 10% → 90% at night.

Three BESS cases appear in this paper and they must not be mixed (Table 6): the design case D, the distributed units of the PV-expansion scenario S3, and the partial dispatch P used in the load-flow study of scenario S4 (Section 3.4).

Table 6: BESS cases used in this paper and the results that belong to each.

Case	Rated power / energy	Dispatch and daily energy	SOC check	Results obtained with it
D (design)	5.6 MW / 11.7 MWh (45 packs in 3 units)	Discharge 17:30–22:30: 9.36 MWh (mean 1.87 MW, maximum need 2.2 MW). Charge 00:00–06:00: 10.4 MWh at $\eta = 0.90$ (mean 1.73 MW)	90% → 10% → 90% (usable 80% × 11.7 = 9.36 MWh)	Sizing (Section 2.6) and cash flow (Section 3.5) only; technical effects not simulated
S3 (distributed)	0.77 MW at three PV sites; set-point 0.7 MW (Table 5)	Fixed power set-points of Table 5. The source data give no energy rating, and the load-flow and RMS runs do not need one	Not applicable (power set-point only; no energy or SOC model)	Voltage, loss and RMS results of Section 3.3
P (partial dispatch)	Equivalent to one 3.9 MWh / 1.875 MW unit	Discharge 0.62 MW × 5 h = 3.10 MWh. Charge 0.52 MW × 6.5 h = 3.38 MWh (implied $\eta = 0.917$)	90% → 10% → 90% of one unit (usable 3.12 MWh); 33% of its power rating	Load levelling, loss and voltage results of Section 3.4 (Figure 7)

Only Case D is the system whose investment is evaluated (Section 3.5), and only Cases S3 and P were simulated in the network. The technical benefits in Section 3.4 therefore belong to Case P, which has about 11% of the design power and 33% of the design daily energy, and they are not results of the 11.7 MWh system. For Case D the sizing target itself implies an evening peak of 9.9 MW instead of 12.12 MW (–18%), but the voltage and loss effects of that dispatch were not simulated.

Table 7: Main data of one BESS container pack (LiFePO₄).

Parameter	Value
Cell chemistry	LiFePO ₄ (LFP)
DC nominal voltage / operating range	806.4 V / 706–907 V
DC charge and discharge current (standard / max.)	140 A / 176 A
Usable energy per pack	261 kWh
AC rated power per pack; voltage	125 kW; 400 V, 3P+N+PE, 50/60 Hz
Power factor range	0.8 capacitive – 0.9 inductive
System efficiency; switching time	89%; < 100 ms
Communication	CAN (battery), RS485 (data), LAN + 4G (cloud)

2.7 Financial evaluation

The investment is evaluated over a 20-year life with the net present value (NPV), the internal rate of return (IRR) and the discounted payback period. All flows are nominal and before tax and financing. The discount rate is the weighted average cost of capital (WACC), and the IRR is computed on the same nominal flows:

$$NPV = \sum_{t=1}^N \frac{B_t - C_t}{(1+r)^t} - C_0, \quad \sum_{t=1}^N \frac{B_t - C_t}{(1+IRR)^t} = C_0 \quad (7)$$

where B_t and C_t are the benefits and costs in year t , C_0 the initial investment (year 0) and r the discount rate,

$$WACC = \frac{E}{V}K_e + \frac{D}{V}K_d(1 - T_c) \quad (8)$$

with E and D the equity and debt, $V = E + D$, K_e and K_d their costs and T_c the tax rate. The capital structure is 30% equity and 70% bank loan at 9% per year, and a WACC of 6.88% was adopted. Because the cost of equity and the tax rate are not specified, the structure does not by itself determine this value, so r is treated as an input and raised to 12% in the sensitivity analysis. The initial investment is $C_0 = 11.7 \text{ MWh} \times \text{USD } 206.4/\text{kWh} \times \text{VND } 26,333/\text{USD} \times 1.05$ (installation) = VND 66.77 billion. The benefit of the first year is the saving from discharging in peak hours minus the cost of charging,

$$B_1 = N_{pk}E_d p_{pk} + N_{su}E_d p_n - 365 \frac{E_d}{\eta} p_{ch} \quad (9)$$

and later benefits follow

$$B_t = B_1[(1 + g)(1 - f)]^{t-1} \quad (10)$$

where $E_d = 9.36 \text{ MWh/day}$ is the energy discharged by Case D, $\eta = 0.90$ the round-trip efficiency, $p_{pk} = 5,025 \text{ VND/kWh}$ and $p_n = 2,887 \text{ VND/kWh}$ the peak and normal prices of the business tariff for 22 kV and above [19], $N_{pk} = 313$ days (Monday to Saturday) and $N_{su} = 52$ Sundays, on which there is no peak period [20] and the discharge is paid at the normal price. The mean charging price $p_{ch} = 957 \text{ VND/kWh}$ lies in the range of 700–1,100 VND/kWh assumed for off-peak purchases and was calibrated so that $B_1 = \text{VND } 12.49$ billion, the first-year benefit used in the underlying study. The tariff escalation is $g = 5\%$ per year (nominal) and the capacity fade $f = 1\%$ per year. Costs are the operation and maintenance cost of VND 31.8 million per year in years 2–11 and VND 63.6 million per year in years 13–20, and an overhaul of VND 3.24 billion in year 12. The revenue is the retail business tariff, i.e. the cost avoided by a customer; the avoided wholesale cost of a utility would be lower, which is why the price spread is varied in Section 3.5.

3 RESULTS AND DISCUSSION

3.1 Base case: voltages and losses with existing PV

Figure 3 shows the steady-state voltage profile. At 11:00 the 22 kV node voltages fall from 1.045 p.u. at the ADO bus to 1.024 p.u. at the end of the feeder; at 20:00 the profile is lower, between 1.042 p.u. and 1.013 p.u., because of the evening load. At 0.4 kV the 49 monitored busbars lie between 1.016 and 1.026 p.u. at 11:00 and between 1.003 and 1.015 p.u. at 20:00. The 25 busbars at PV sites are on average 0.1 percentage points higher than the others at 11:00. All voltages are inside the $\pm 5\%$ band, and the highest value, 1.045 p.u., is the substation busbar, not a PV connection point. At the present penetration (about 15% of the noon load) PV therefore causes no overvoltage on this feeder; the voltage drop from noon to the evening peak is about 1 percentage point at both voltage levels.

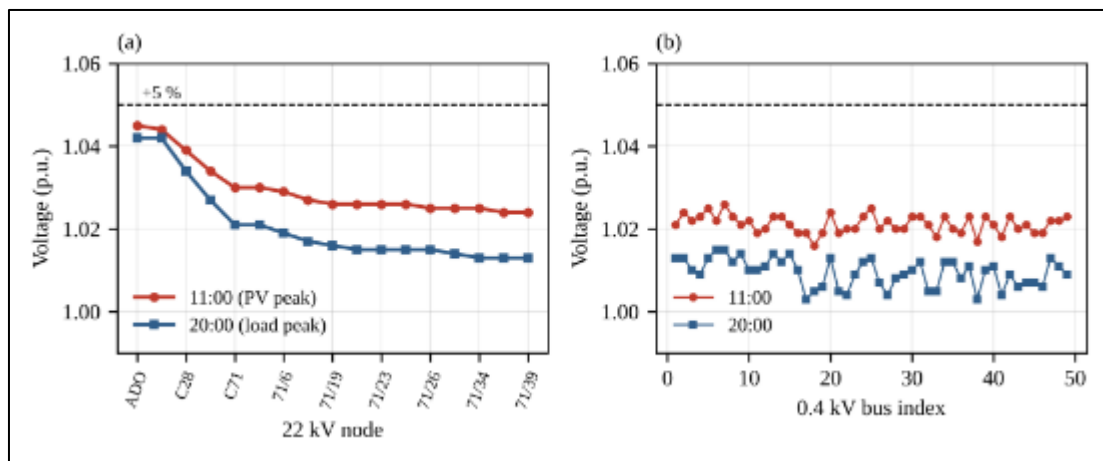


Figure 3: Base-case voltages at 11:00 and 20:00: (a) 22 kV nodes along the feeder; (b) 49 monitored 0.4 kV busbars. The dashed line marks the +5% limit.

Network losses follow the load rather than the PV output. At 11:00 the active and reactive losses are 0.084 MW and 0.414 MVar; at 20:00 they reach 0.19 MW and 0.93 MVar, i.e. about 2.3 times as high (Figure 5a, baseline curve). The daily active-energy loss is 2.50 MWh, or 1.13% of the 221.0 MWh delivered. The evening peak is thus the critical operating condition for losses and voltage drop, not the noon PV peak.

3.2 Weather events: cloud cover and thunderstorm

Figure 4 shows the RMS results (model in Section 2.4). When the 0.51 MWp Nam Cuong plant loses its full output at 10 s (cloud, S2a), the local bus frequency shows a short dip to 49.816 Hz and recovers to 50 Hz; at the other buses the dip is only 49.996 Hz. The voltage of the Nam Cuong busbar changes from 1.0218 p.u. to 1.0210 p.u., and 22 kV and neighbouring LV nodes change by about 0.001 p.u. The voltage returns to its initial value when the output is restored at 20 s. In the thunderstorm case (S2b), where three plants disconnect at 10 s and all plants at 20 s, the lowest bus frequency is 49.891 Hz (Hakawa) at the first step and 49.847 Hz (Duy Thinh T3) at the second step; the 0.4 kV voltages fall in two steps of about 0.001 p.u. each, e.g. from 1.027 to 1.026 and then 1.025 p.u. at the Hakawa and Duy Thinh T4 busbars. The voltage steps are negligible against the $\pm 5\%$ band, and the frequency indicator stays inside the ± 0.2 Hz screening reference (Section 2.4).

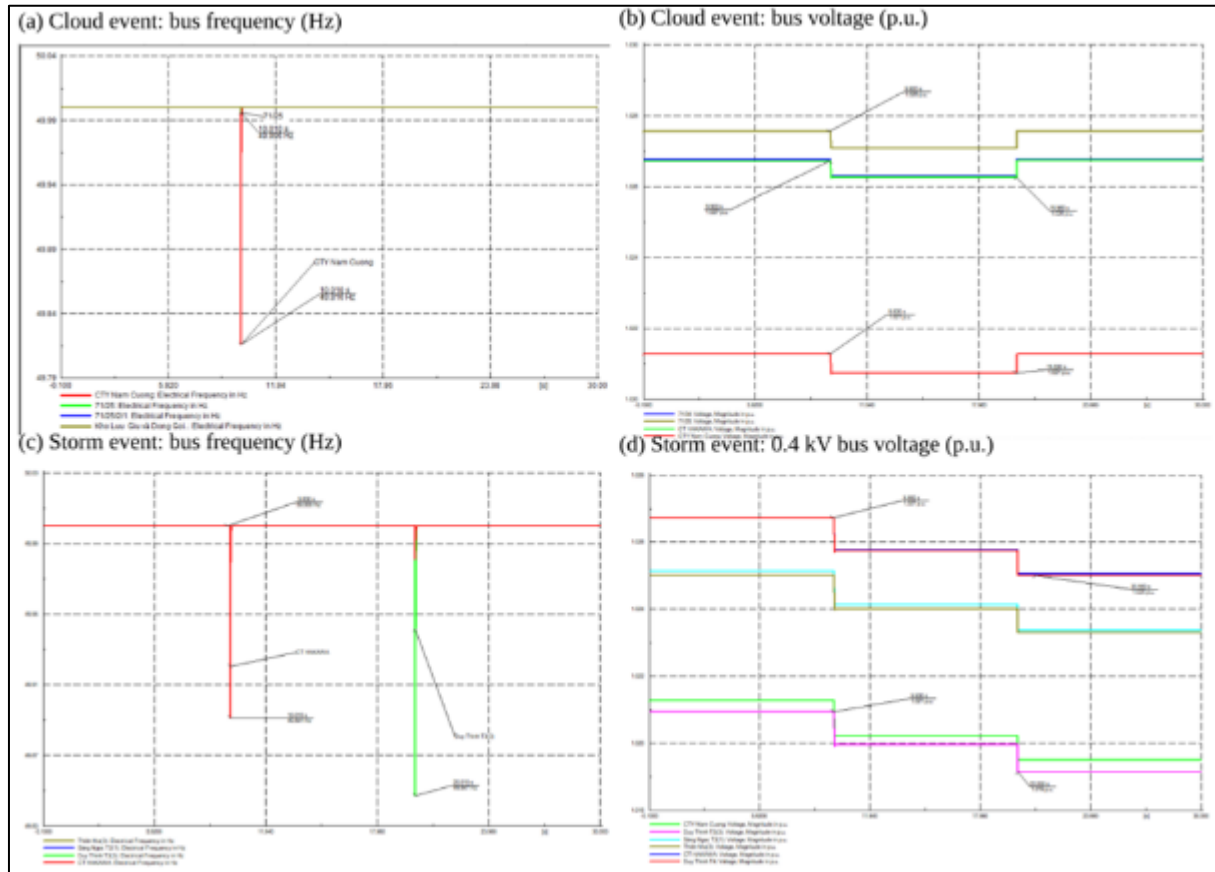


Figure 4: RMS simulation results (PowerFactory output). Cloud event at the Nam Cuong plant: (a) bus frequency, (b) bus voltage. Thunderstorm event: (c) bus frequency, (d) 0.4 kV bus voltage. Events occur at 10 s and 20 s.

These results indicate that, at the present PV share, the simulated loss of PV output produces no voltage problem on the feeder. The frequency traces must be read with the model limits of Section 2.4 in mind: the signal is local to each bus, PV is a constant-power static generator without inverter dynamics, and the dips appear as very short spikes that coincide with the steps in injected power. Such a spike is what is expected when a step change of power moves the voltage angle across the feeder impedance and the frequency signal is derived from the rate of change of that angle. As the upstream network is modelled as an external grid, whose frequency cannot change, the spike is a transient of the local model, not evidence of a change in system frequency, and the values of 49.816–49.847 Hz should not be compared directly with the grid-code limits.

3.3 PV expansion with distributed BESS (scenario S3)

Doubling the PV capacity to 3.8 MWp, with BESS at three of the new sites, raises the noon PV output to about 2.8 MW (30% of the 11:00 load). The voltage at all 22 kV nodes increases slightly (mean 1.0297 $\rightarrow$ 1.0326 p.u., maximum local increase 0.4 percentage points) and the 0.4 kV voltages at the PV sites rise by 0.2–0.6 percentage points (mean 1.0216 $\rightarrow$ 1.0255 p.u.). The maximum voltage remains 1.045 p.u. (substation bus) at 22 kV and 1.029 p.u. at 0.4 kV (Figure 5b, c), so the voltage limits are still respected.

At 11:00 the active and reactive losses fall from 0.084 MW and 0.414 MVar to 0.060 MW and 0.296 MVar, i.e. by 28% and 28%, because the new PV sits close to the loads and reduces the current in the upstream sections. Over 24 h the active-energy loss falls from 2.50 to 2.21 MWh (−11.5%) and the reactive-energy loss by 13.3% (Figure 5a). At the evening peak the loss reduction is only 3.4% (0.194 → 0.187 MW), since the BESS in this scenario is small (total 0.7 MW) compared with the evening demand.

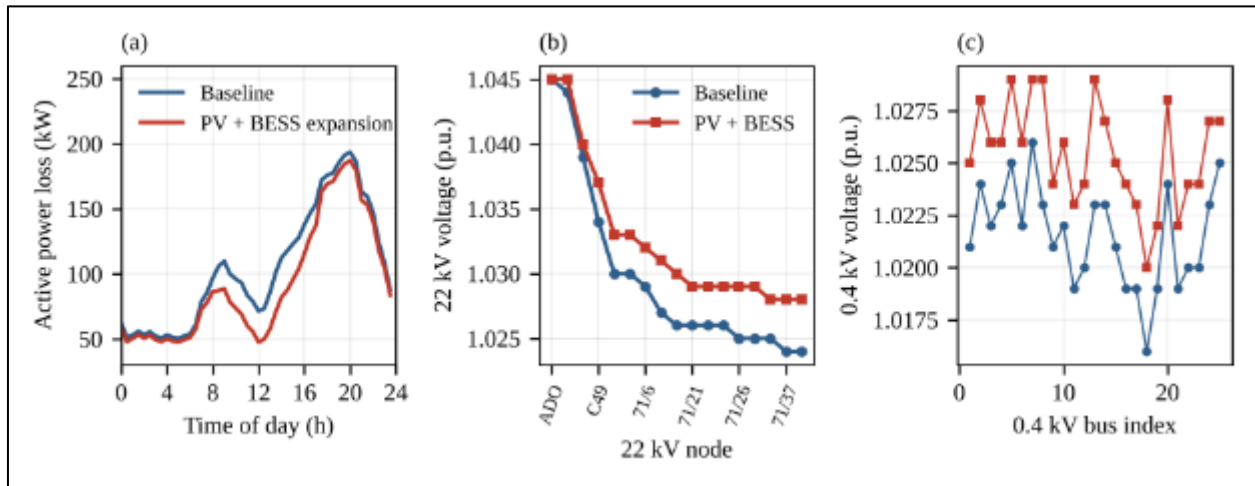


Figure 5: Effect of PV expansion and BESS (scenario S3) compared with the baseline: (a) active power loss over 24 h; (b) 22 kV node voltages at 11:00; (c) 0.4 kV busbar voltages at PV sites at 11:00.

When the storm event is repeated on the expanded system (Figure 6), the bus voltages stay between 1.018 and 1.030 p.u. throughout. The bus-frequency indicator is larger: 49.869 Hz at the first step and 49.805 Hz (Nam Cuong busbar) at the second, against 49.847 Hz in the base case. The indicator therefore grows with the amount of PV lost in one step (the second step now removes about 2.8 MW instead of 1.4 MW at 11:00), which is the expected direction. Its absolute value cannot be read as a distance to the ± 0.2 Hz limit, because the model contains neither the dynamics of the upstream grid nor inverter and BESS controls (Section 2.4). Whether a larger PV share would approach a frequency limit, and whether a BESS with fast frequency response would help, requires a dynamic model with these elements and is left for future work.

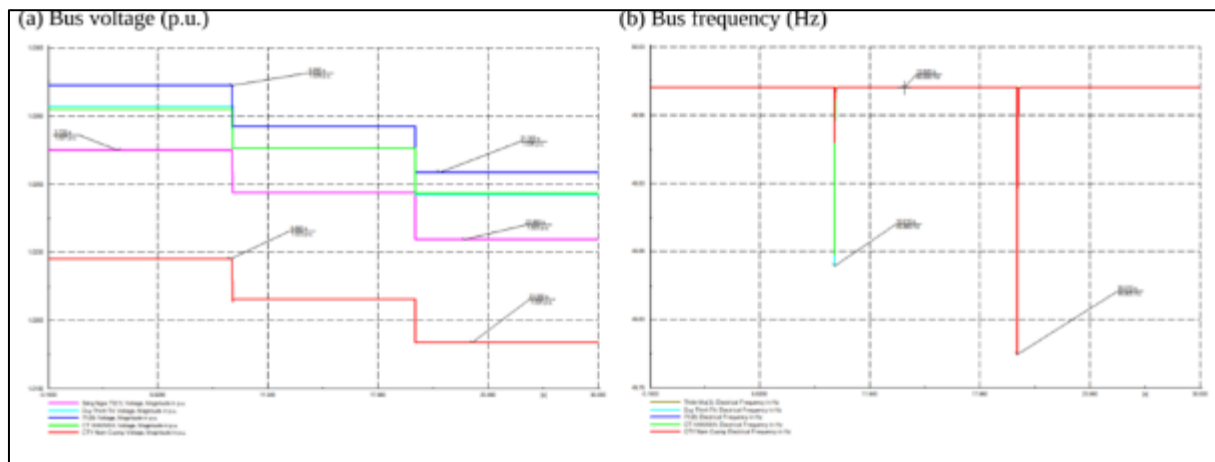


Figure 6: Thunderstorm event on the expanded system (S3): (a) bus voltages; (b) bus frequencies (PowerFactory output).

3.4 Load-levelling BESS (scenario S4)

In the power-flow study the BESS was represented by a dispatch of +0.52 MW (charging) between 00:00 and 06:30 and −0.62 MW (discharging) between 17:30 and 22:30, applied to the aggregate load of the feeder; this is Case P of Table 6. The corresponding energies are $0.62 \text{ MW} \times 5 \text{ h} = 3.10 \text{ MWh}$ discharged and $0.52 \text{ MW} \times 6.5 \text{ h} = 3.38 \text{ MWh}$ drawn from the grid, an implied round-trip efficiency of 91.7%, consistent with the 90% assumed in Section 2.7. This is the energy range of a single 3.9 MWh container cycled between 90% and 10% state of charge (usable 3.12 MWh) at about one third of its 1.875 MW rating, and it equals about 11% of the design power and 33% of the design daily energy of Case D (Section 2.6). The results of this section therefore describe a partial-deployment case; the load-levelling effect of the full

5.6 MW / 11.7 MWh design was not simulated. Figure 7a shows the resulting load curve. The night valley increases from 6.39 MW to 6.91 MW (+8.1%) and the evening peak decreases from 12.12 MW to 11.50 MW (−5.1%); the daily energy rises by 0.28 MWh, the round-trip loss of the battery (3.38 – 3.10 MWh).

The flatter load improves the evening voltage (Figure 7b): the mean 22 kV voltage at 20:00 rises from 1.0207 to 1.0226 p.u. and the lowest from 1.013 to 1.016 p.u.; at 0.4 kV the mean rises from 1.0106 to 1.0131 p.u. (+0.25 percentage points). The voltage gain is small because the base case was already within limits, so the voltage benefit of the BESS is secondary compared with its effect on losses.

Active power loss at 20:00 falls from 0.19 MW to 0.15 MW (−21%) and reactive power loss from 0.93 MVar to 0.75 MVar (−19%) (Figure 7c). Because losses are proportional to the current squared, a 5% reduction of the feeder current would reduce losses by only about 10%; the larger reduction found here should be verified with a loss-sensitivity study.

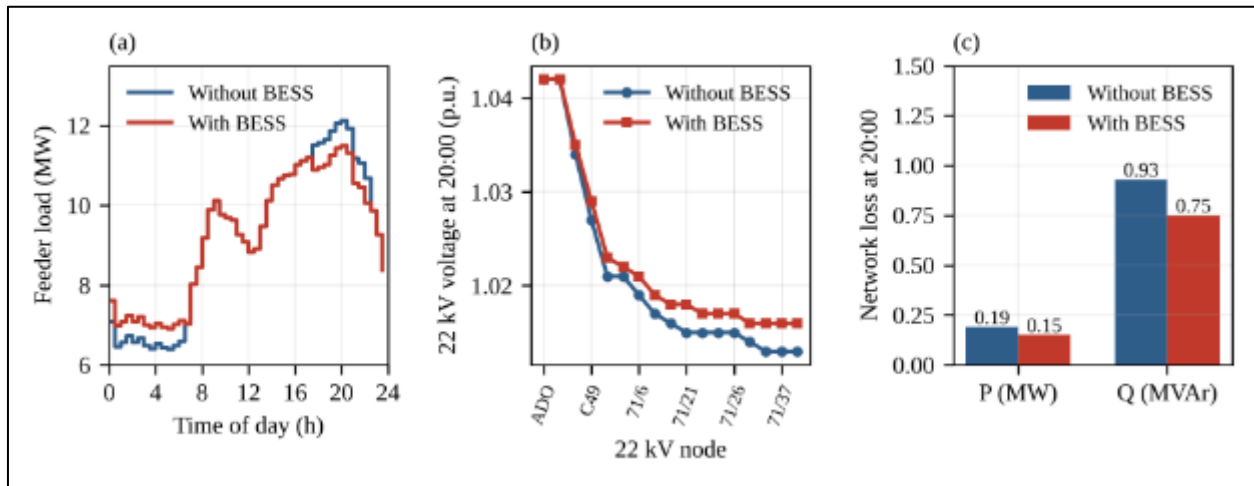


Figure 7: Effect of the load-levelling BESS (S4): (a) feeder load over 24 h; (b) 22 kV voltages at 20:00; (c) network losses at 20:00.

3.5 Financial evaluation and sensitivity

The investment is the design case D (Table 6). Table 8 gives the complete nominal cash flow so that every figure can be checked: the investment of VND 66.77 billion in year 0 (11.7 MWh at USD 206.4/kWh plus 5% installation), a first-year benefit of VND 12.49 billion, and benefits growing by $(1 + g)(1 - f) - 1 = 3.95\%$ per year. All flows, including the costs, are discounted at the WACC of 6.88%. The result is NPV = VND 113.2 billion, IRR = 21.8% (nominal) and a discounted payback of 6.1 years, i.e. in the seventh year (cumulative present value −1.4 billion at the end of year 6 and +8.5 billion at the end of year 7).

Table 8: Nominal cash flow of the 11.7 MWh BESS (Case D), million VND.

Year	Benefit B_t	Cost C_t	Net	Discount factor	PV of net	Cumulative PV
0	–	66,771	-66,771	1.0000	-66,771	-66,771
1	12,494	0	12,494	0.9356	11,689	-55,081
2	12,987	32	12,955	0.8754	11,341	-43,740
3	13,500	32	13,468	0.8191	11,031	-32,709
4	14,033	32	14,002	0.7663	10,730	-21,979
5	14,588	32	14,556	0.7170	10,436	-11,543
6	15,164	32	15,132	0.6708	10,151	-1,392
7	15,763	32	15,731	0.6277	9,874	8,482
8	16,385	32	16,354	0.5873	9,604	18,086
9	17,033	32	17,001	0.5495	9,341	27,427
10	17,705	32	17,674	0.5141	9,086	36,513

11	18,405	32	18,373	0.4810	8,837	45,350
12	19,132	3,243	15,889	0.4500	7,150	52,501
13	19,887	64	19,824	0.4211	8,347	60,848
14	20,673	64	20,609	0.3940	8,119	68,967
15	21,490	64	21,426	0.3686	7,898	76,865
16	22,338	64	22,275	0.3449	7,682	84,547
17	23,221	64	23,157	0.3227	7,472	92,019
18	24,138	64	24,074	0.3019	7,268	99,287
19	25,092	64	25,028	0.2825	7,070	106,356
20	26,083	64	26,019	0.2643	6,876	113,233
Total	370,110	70,840	299,270		113,233	

$B_t = B_1[(1+g)(1-f)]^{t-1}$ with $B_1 = 12,494$ and $g = 5\%$, $f = 1\%$. Costs: investment in year 0; operation and maintenance 31.8 per year (years 2–11) and 63.6 per year (years 13–20); overhaul 3,243 in year 12. Discount factor = $1/1.0688^t$. Totals of B and C are nominal; the cumulative PV column ends at the NPV.

3.5.1 Feasibility of the revenue

The benefit assumes one full cycle on each of 365 days. For Case D this means 9.36 MWh discharged over the 5 h peak window at 1.87 MW on average (33% of the rating) and 10.4 MWh charged within the 6 h off-peak window at 1.73 MW (Table 6), so the schedule is physically feasible at the aggregate level. It implies 7,300 full-depth cycles in 20 years, which has to be supported by the manufacturer's warranty; whether the local demand at each of the three substations covers the discharge in every peak half-hour (the no-reverse-flow constraint of Section 2.6) was not checked. Table 8 does not use the simulated Case P: the technical results of Section 3.4 do not validate the revenue of Case D, and the revenue of Case D does not follow from them.

3.5.2 Sensitivity

Table 9 varies one assumption at a time and then several together. NPV stays positive in every single-factor case, but it is strongly dependent on three commercial assumptions: the tariff escalation (NPV 55.7 billion without escalation), the peak price (NPV 27.5 billion at –40%) and the service life (36.5 billion for 10 years). The NPV is zero if the peak price falls to 2370 VND/kWh (53% below the assumed value), or to 3115 VND/kWh if there is no escalation, or if the investment cost is 2.7 times the assumed value. Round-trip efficiency and capacity fade have a smaller effect. Under the combined adverse case A the NPV is only VND 10.6 billion (IRR 8.6%, below the 10% discount rate tested), and under case B it is negative. A positive NPV is therefore not a firm conclusion: it holds only if the peak tariff spread, its escalation and the battery life are confirmed. The analysis also omits tax, financing flows, the value of deferred network reinforcement and of the reduced losses of Section 3.4.

Table 9: Sensitivity of the financial result (Case D).

Case	NPV (VND billion)	IRR (%)	Discounted payback (years)
Base case	113.2	21.8	6.1
Investment cost +20%	99.6	18.2	7.5
Investment cost +40%	85.9	15.6	8.9
Peak price –20%	70.4	16.7	8.3
Peak price –40%	27.5	11.1	13.0
Half of the discharge paid at the normal price	67.6	16.4	8.5
Tariff escalation 0%	55.7	16.9	7.2
Tariff escalation 3%	86.5	19.8	6.5
Round-trip efficiency 85%	110.1	21.4	6.3
Capacity fade 2% per year	98.3	20.7	6.3

Capacity fade 3% per year	85.1	19.7	6.5
Service life 15 years	76.9	20.5	6.1
Service life 10 years	36.5	16.8	6.1
Discount rate 10%	71.8	21.8	6.9
Discount rate 12%	52.4	21.8	7.6
Battery replacement in year 12 (40% of C_0)	101.2	20.9	6.1
Combined A: investment +20%, peak price –20%, escalation 0%, $\eta = 85\%$	10.6	8.6	15.5
Combined B: investment +40%, half of discharge at normal price, escalation 0%, $\eta = 85\%$, fade 2%	-11.1	5.2	> 20

One assumption is changed at a time unless stated. In the 10- and 15-year cases the benefits stop at the end of the life and no overhaul is incurred (the overhaul falls in year 12). Replacement in year 12 adds 40% of C_0 to the cost of that year.

Limitations

The conclusions should be read with the following limitations. (i) One feeder and one set of measured profiles (a June day) were used, so seasonal and day-to-day variability are not represented. (ii) The load flow is a balanced positive-sequence model; phase unbalance on the 0.4 kV side and harmonics are not captured. (iii) PV inverters were modelled at unity power factor ($\cos \varphi = 1$) without Volt-VAR or Volt-Watt control, and the BESS was represented by scheduled power, without converter control or state of charge; the S3 units are defined by power only, with no energy rating. (iv) The RMS model uses constant-power static generators, no inverter controls and no upstream-grid dynamics, and its frequency is a local bus signal; the frequency results are a screening indicator, not a system-frequency study (Section 2.4). (v) The network simulations cover Cases S3 and P, which are smaller than the design Case D; the loss and voltage benefits of the full design are not demonstrated, and the economics of Case D must not be combined with the technical results of Case P (Section 2.6). (vi) The financial model is nominal, pre-tax, with fixed tariffs; it values the discharge at the retail business tariff rather than at the utility's avoided cost, it depends strongly on the assumed tariff escalation and on the peak window of [20] being reflected in retail prices, and it includes no network-deferral benefit (Section 3.5). Addressing these points with time-series simulation, a dynamic model with inverter and upstream-grid representation, and optimisation of BESS siting and size is a natural continuation of this work.

4 CONCLUSION

This paper assessed the effect of rooftop PV and BESS on a real 22 kV urban feeder in Da Nang City using measured profiles and a PowerFactory model. The main findings are:

- With 1.9 MWp of existing PV (about 15% of the noon load) there is no overvoltage: 22 kV voltages are between 1.013 and 1.045 p.u. and 0.4 kV voltages between 1.003 and 1.026 p.u., all inside $\pm 5\%$. The evening peak, not the noon PV peak, is the critical condition for voltage drop and losses (0.19 MW versus 0.08 MW).
- Simulated cloud and thunderstorm events cause voltage steps of about 0.001 p.u. The local bus-frequency indicator shows short spikes (minimum 49.847 Hz in the base case, 49.805 Hz with PV doubled) that grow with the PV power lost in one step; because the model has no inverter control or upstream-grid dynamics, this is a relative indicator only and does not demonstrate compliance or non-compliance with the system-frequency limits.
- Doubling PV with distributed BESS reduces the noon loss by 28% and the daily energy loss by 11.5% and increases voltages by 0.2–0.6 percentage points without violating limits.
- A partial-deployment load-levelling dispatch (Case P: 0.62 MW, about 11% of the design power) cuts the evening peak by 5.1%, raises the valley by 8.1% and reduces losses at 20:00 by 21% (active) and 19% (reactive). The effect of the full 5.6 MW / 11.7 MWh design was not simulated.
- The 11.7 MWh BESS investment (VND 66.77 billion) gives NPV = VND 113 billion, IRR = 21.8% and a discounted payback of about 6 years under the stated tariff assumptions. The result is sensitive to the tariff escalation, the peak price and the battery life, and becomes marginal under combined adverse assumptions, so it should be treated as preliminary.

Recommendations for the utility are to (a) consider BESS near the feeder end, where the evening load is concentrated, once the commercial assumptions of Section 3.5 are confirmed, (b) require smart-inverter functions (Volt-VAR, Volt-Watt, frequency-power droop) for new PV connections, and (c) study frequency and inverter dynamics with a model that includes inverter controls and the upstream grid before approving a large further increase of the PV share. Future

work should add time-series simulation over a full year, inverter and storage control (including grid-forming control), simulation of the full-capacity BESS and optimal siting and sizing of storage.

STATEMENTS ON COMPLIANCE WITH ETHICAL STANDARDS

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Disclosure of conflict of interest

No conflict of interest to be disclosed.

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