



Scenario-Based Evaluation of Candidate BESS Discharge Set-Points in the Sulselrabar 150-kV System

Khusnul Khatimah Assagaf ^{a,*}, Diva Mauliya ^a

^a *Electrical Engineering Department, Polytechnic State of Ujung Pandang, Makassar, Indonesia.*

ABSTRACT

Battery energy storage systems can reduce transmission losses and support network operation, but their technical benefit depends on location, operating power, and system condition. This study presents a scenario-based evaluation of a candidate BESS connected at the Sungguminasa 150-kV bus in the South, Southeast, and West Sulawesi (Sulselrabar) interconnected system, Indonesia. The study uses a 43-bus representation derived from historical PLN/AP2B system data documented for 21 May 2019. The published base case comprises 50 transmission lines, a total transmission loss of 12.123 MW, a maximum reported branch transfer of 171.25 MW on the Tallasa-Sungguminasa corridor, and a minimum 150-kV bus voltage of 148.091 kV (0.9873 pu). Sungguminasa was selected as a candidate location because it lies on the highest-transfer corridor in the documented snapshot. Five discharge-power set-points, 0, 25, 50, 75, and 100 MW, were compared using a calibrated steady-state load-flow model. The minimum calibrated active loss of 11.425 MW occurs at 75 MW, corresponding to a 5.76% reduction from the historical base loss, while the 50-MW case gives 11.435 MW and is only 0.010 MW higher. Increasing discharge to 100 MW raises losses to 11.654 MW, demonstrating non-monotonic power-flow redistribution and diminishing marginal benefit. Accordingly, 75 MW is identified as the best tested discrete set-point for this single historical snapshot, not as a continuous mathematical optimum or a complete BESS size. The result remains sensitive to model calibration, operating condition, BESS location, energy duration, state of charge, degradation, and economic assumptions that were not modeled.

Keywords: battery energy storage system; scenario-based evaluation; transmission loss; load flow; discharge set-point;

1. Introduction

The increasing demand for electricity, together with global decarbonization initiatives and the rapid deployment of renewable energy resources, has accelerated the modernization of electric power systems [1]. At the same time, maintaining system reliability and operational flexibility has become increasingly challenging because renewable energy sources such as solar and wind exhibit intermittent generation characteristics [2].

From an operational perspective, reducing transmission losses is an important objective because technical losses influence network efficiency and the amount of upstream generation required to serve demand. However, the present study does not implement a continuous optimization algorithm. It evaluates a finite candidate set of BESS discharge powers and identifies the best tested scenario under one historical network condition.

Battery Energy Storage Systems (BESS) have emerged as one of the most effective technologies for improving the operational performance of modern power systems. Besides

storing surplus electrical energy, BESS can provide voltage regulation, frequency support, peak shaving, spinning reserve, and improved integration of renewable energy resources into transmission and distribution networks [3, 4].

In recent years, electric utilities have increasingly adopted computational simulation as an effective approach for evaluating transmission-system performance under different operating scenarios. Compared with direct field testing, simulation provides greater flexibility for investigating multiple operating conditions while minimizing operational risks and implementation costs. Load-flow studies are therefore widely employed to assess voltage profiles, transmission losses, power-flow distribution, and the overall technical feasibility of integrating new technologies such as Battery Energy Storage Systems into existing power networks.

Recent developments in battery technologies and power electronic converters have significantly enhanced the technical capability of BESS. Modern energy storage systems are capable of responding rapidly to power

* Corresponding author.

E-mail addresses: khusnul280305@gmail.com.

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fluctuations while improving overall grid stability and operational efficiency [5, 6].

Numerous studies have investigated BESS placement, sizing, dispatch, voltage support, and energy management using optimization methods such as optimal power flow, evolutionary algorithms, and multi-objective formulations [7, 8]. Those approaches can search a continuous or combinatorial decision space but generally require a fully specified and validated network model, chronological operating data, and clearly defined technical and economic objectives [9, 10].

A practical gap remains between advanced optimization studies and the preliminary screening required when only a traceable historical utility snapshot is available. For the Sulselrabar system, published studies provide a documented 43-bus operating case and transmission-loss reference, but recent peer-reviewed analyses of a candidate BESS set-point at a traceable Sulselrabar transmission bus remain limited. The contribution of this study is therefore methodological transparency rather than a new optimization algorithm: it reconstructs a documented historical case, separates historical data from hypothetical BESS injections, evaluates every candidate in a predefined discrete set, and explicitly reports the limits of calibration and generalizability [11, 12].

In this study, a candidate BESS is connected at the Sungguminasa 150-kV bus and evaluated at five discharge-power set-points: 0, 25, 50, 75, and 100 MW. The study is intentionally framed as a parametric scenario evaluation. Sungguminasa is a candidate site selected from the high-transfer Tallasa-Sungguminasa corridor; no claim is made that it is the globally optimal BESS location.

The primary objective is to compare the tested discharge set-points with respect to active transmission loss while retaining voltage feasibility. The scientific contribution is a transparent Indonesian transmission-system case study that quantifies the non-monotonic loss response to local BESS injection, identifies diminishing marginal benefit near the best tested region, and shows why discrete scenario ranking must be interpreted together with model uncertainty and operating-condition limitations.

In this study, a BESS is installed at the Sungguminasa 150-kV bus to evaluate its influence on transmission losses and bus voltage profiles under several discharge-power scenarios. Five operating conditions, namely 0 MW, 25 MW, 50 MW, 75 MW, and 100 MW, are investigated using steady-state load-flow analysis [13, 14].

The primary objective of this study is to determine the BESS operating point that provides the greatest reduction in transmission losses while maintaining acceptable voltage performance. The findings are expected to provide practical recommendations for future BESS implementation in the Sulselrabar transmission system and other power systems with similar operating characteristics [15].

2. Methods and modelling

2.1. Methodological framework

The research workflow comprises historical-system data preparation, base-case calibration, candidate-site selection, BESS scenario definition, steady-state load-flow screening, technical comparison, and identification of the best tested discrete set-point. The method is a complete enumeration of a predefined candidate set rather than continuous optimization.

The objective is to compare active transmission losses while maintaining the adopted 0.95-1.05 pu voltage-feasibility range.

The network representation is based on historical data from the PLN Load Dispatch and Control Centre for Sulselrabar, as documented in a previous Sulselrabar study and related publication [16]. The dataset represents operation on 21 May 2019 at 15:00 WITA and contains 43 buses, 50 transmission lines, generation units, transformers, substation loads, and network parameters. The published historical reference reports a total transmission loss of 12.123 MW, a minimum 150-kV bus voltage of 148.091 kV at Palopo, and the highest reported branch transfer of approximately 171.25 MW on the Tallasa-Sungguminasa corridor. These quantities are used as historical calibration anchors, not as independent contemporary validation measurements.

A candidate BESS was connected to the Sungguminasa 150-kV bus and evaluated at 25, 50, 75, and 100 MW discharge, together with the 0-MW reference. Sungguminasa was selected because it is connected to the highest-transfer corridor in the documented snapshot. This is a physically motivated candidate-site selection, not a location-optimization result. All non-BESS network inputs are held fixed so that the effect of the tested active-power injection can be compared consistently.

The workflow distinguishes input preparation, calibration, scenario execution, and interpretation [17-19]. During input preparation, the buses, transmission branches, generating units, loads, transformer connections, and voltage bases documented in the source studies are organized into a consistent network representation. The historical timestamp is retained because it defines the generation-load balance to which the BESS scenarios are applied [20]. Mixing network data from different operating periods would weaken traceability and could produce a base condition that never existed physically [21].

Calibration uses the published 0-MW transmission loss of 12.123 MW as the principal anchor, with the reported minimum voltage and high-transfer corridor as additional reasonableness checks. This process aligns the scenario model with the published historical case but does not constitute independent validation against a current PLN model, SCADA measurements, or another software implementation. Consequently, the absolute third-decimal precision of the hypothetical BESS losses should be interpreted cautiously.

Scenario quality control includes power-balance checking, numerical convergence, confirmation that every tested BESS value belongs to the predefined candidate set, and voltage-feasibility screening. The response is also examined for marginal changes between adjacent set-points. Because the 50- and 75-MW losses differ by only 0.010 MW, approximately 0.09% of the 75-MW loss value, scenario ranking is discussed together with calibration uncertainty rather than treated as an exact global optimum.

The procedure is a complete enumeration of five discrete candidates rather than a continuous mathematical optimization. Enumeration is appropriate for this limited screening set because every alternative is solved directly and no search algorithm is required. The term 'best tested set-point' is therefore used throughout the revised manuscript. A formal optimization study would require a continuous or mixed decision formulation, explicit constraints, validated model inputs, and an algorithm such as OPF, PSO, GA, differential evolution, or another suitable method.

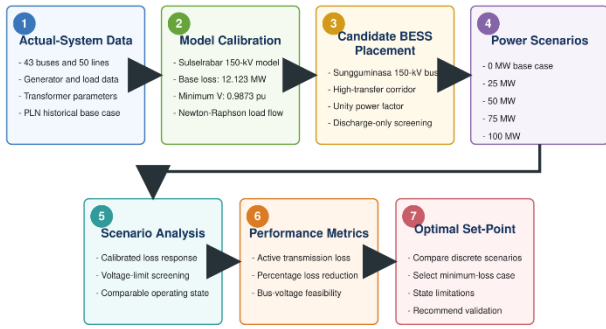


Fig. 1. Methodological framework for calibrated BESS discharge-power screening.

2.2. System description

The investigated object is the Sulselrabar 150-kV interconnected power system, covering South Sulawesi, Southeast Sulawesi, and West Sulawesi. The documented model contains 43 buses and 50 transmission lines and includes hydro, steam, gas, combined-cycle, micro-hydro, and wind generation connected to the regional transmission network [12].

The historical operating case includes the 75-MW Sidrap wind farm and the 72-MW Tolo Jeneponto wind farm. Published load-flow results report a total active-power flow of 1,730.87 MW across the monitored branches and a maximum branch transfer of approximately 171.25 MW from Tallasa to Sungguminasa. Total active transmission losses are 12.123 MW, with the largest individual line loss occurring on the Bakaru-Pinrang corridor [12].

The BESS is not presented as an existing PLN installation. It is a candidate planning option connected to the Sungguminasa 150-kV bus. The investigated values of 25–100 MW are discharge-power set-points, not complete storage capacities. A practical design would additionally require an energy rating in MWh, discharge duration, state-of-charge limits, converter rating, efficiency, degradation limits, and grid-code controls.

For steady-state screening, the BESS is represented as a controllable active-power injection operating at unity power factor. Reactive-power control is excluded so that changes in transmission loss can be attributed primarily to active-power redistribution. This equivalent representation is appropriate for load-flow screening but does not reproduce the dynamic behaviour of a converter-interfaced battery [22, 23].

The historical generation dispatch, load demand, transformer settings, and network topology are held constant across all cases. The BESS discharge set-point is the only sensitivity variable. This design isolates the technical effect of BESS active-power injection at the selected location [24].

A simplified view of the studied Tallasa-Sungguminasa-Tello corridor is presented in Fig. 2. The diagram highlights the candidate connection point and should not be interpreted as the complete confidential PLN single-line diagram.

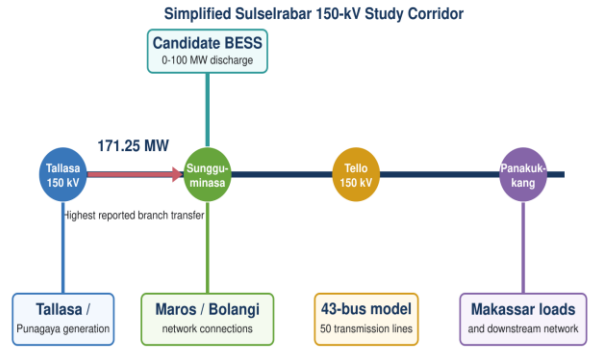


Fig. 2. Simplified Sulselrabar 150-kV study corridor and candidate BESS connection at Sungguminasa.

The system boundary includes the 43-bus transmission representation, its generation and load buses, and the candidate BESS connection. The analysis is limited to steady-state discharge operation. Charging cases, chronology, state of charge, degradation, converter dynamics, contingencies, and protection coordination are outside the study scope [4, 25].

The regional character of the network is important for interpreting the candidate location. Sulselrabar interconnects generation technologies and load centers distributed across three provinces. The documented generation mix includes dispatchable and variable renewable sources, while long transmission paths transfer power toward major demand areas. Under such conditions, a local injection can influence more than the immediately adjacent line. Kirchhoff's laws redistribute the incremental power through all electrically available paths according to network impedances and operating angles [26].

Sungguminasa was selected because of its connection to the Tallasa-Sungguminasa corridor and its location in the Makassar-area transmission network. The 171.25-MW historical branch transfer makes it a technically plausible candidate for local injection. Nevertheless, this screening logic does not demonstrate that Sungguminasa is the best location in the 43-bus system. A multi-location study using loss-sensitivity factors, PTDF-based screening, OPF, or metaheuristic optimization is required for a location-optimal conclusion.

Representing the BESS at unity power factor intentionally isolates the effect of active-power injection. Modern grid-forming or grid-following converters can generally exchange reactive power within their apparent-power and control limits, which could change voltage and reactive-flow performance. Excluding this capability makes the present comparison easier to interpret but may understate potential voltage-support value. It also prevents active and reactive control choices from being conflated in a study for which scenario-specific voltage measurements are unavailable [10, 27].

The fixed-dispatch assumption has a similar purpose. In actual operation, system operators may redispatch conventional units when a BESS discharges so that total generation continues to match demand and losses. The bus chosen to absorb the balancing change affects the resulting branch flows. The calibrated cases represent a controlled network-injection sensitivity around the historical condition. They do not reproduce an automatic generation-control

sequence, unit commitment decision, or market settlement [28].

The historical timestamp is one operating point within a much broader operating envelope. The 15:00 WITA snapshot fixes a particular combination of demand, hydrological availability, thermal-unit commitment, and wind generation. Peak, off-peak, weekend, dry-season, wet-season, and high/low renewable conditions could change both the preferred BESS location and set-point. Therefore, the result cannot be generalized to all Sulsebar operating hours without chronological or multi-snapshot validation.

The sign convention used in the scenarios assumes positive BESS power is discharge into the transmission bus. Charging would appear as negative injection and could increase transfer into Sungguminasa if performed during the same network condition. A complete operating strategy should therefore optimize both halves of the storage cycle. Locating charging during low-load or renewable-surplus periods may reduce curtailment, whereas charging during a congested period could erase part of the benefit obtained during discharge [14, 16].

2.3. Mathematical modelling

The steady-state active-power balance is based on the combined contribution of the interconnected grid, conventional and renewable generation, and the candidate BESS. At each scenario, the BESS changes the geographical distribution of active-power supply and therefore the current and loss pattern in the 150-kV network. The system balance is expressed as:

$$P_{Grid} + P_{Gen} + P_{BESS} = P_{Load} + P_{Loss} \quad (1)$$

Where:

P_{Grid}	=	Active power supplied by the utility grid (MW)
P_{Gen}	=	Active power generated by conventional generation units (MW)
P_{BESS}	=	Active power injected by the Battery Energy Storage System (MW)
P_{Load}	=	Total system load demand (MW)
P_{Loss}	=	Total active power losses in the network (MW)

Equation (1) states that grid supply, generation, and BESS discharge must cover the total load and network losses. Positive PBESS denotes discharge into the Sungguminasa bus. The historical generation and demand pattern remains fixed for direct scenario comparison.

The discrete technical decision is to identify the tested BESS discharge set-point that gives the lowest active transmission loss while satisfying the voltage-feasibility constraint for the modeled snapshot. This is a scenario-ranking rule rather than a continuous optimization formulation.

$$\min (P_{Loss}) \quad (2)$$

Where:

P_{Loss}	=	Total active power losses in the network (MW)
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The candidate set is PBESS = {0, 25, 50, 75, 100} MW. The historical 0-MW case is anchored to the published transmission loss of 12.123 MW. The BESS cases are calibrated computational screening results derived from the historical model, not direct PLN operational measurements. The selected value is therefore the best discrete discharge set-point among the tested cases and must not be interpreted as an optimized

MWh capacity, a globally optimal location, or a universal operating command.

2.4. Numerical solution and scenario evaluation

For each candidate, the power-flow problem is solved using the Newton-Raphson method adopted in the documented Sulsebar studies [12]. The state variables comprise bus-voltage angles and, for PQ buses, voltage magnitudes. At each iteration, active- and reactive-power mismatches are calculated from the specified injections and the voltages obtained in the preceding iteration. The Jacobian matrix relates these mismatches to corrections in angle and magnitude. Iterations continue until the mismatch satisfies the convergence criterion used by the computational model.

The BESS is introduced as a positive active-power injection at the Sungguminasa bus. Its reactive injection is set to zero under the unity-power-factor assumption. The 0-MW case is solved first and provides the comparison baseline. The same network admittance matrix, bus classifications, demand pattern, and non-BESS generation assumptions are retained for the 25-, 50-, 75-, and 100-MW cases. This consistency ensures that the scenario label corresponds to a single controlled change [24].

After convergence, active loss is evaluated from the difference between total active generation and total load, with the BESS injection included in the generation side of the balance. It can also be checked by summing branch resistive losses. Agreement between these two calculations is a useful diagnostic for unit conversion, sign convention, and incomplete branch accounting. The calibrated loss values are then compared with 12.123 MW, and the percentage reduction is calculated relative to this common baseline [12].

Voltage feasibility is evaluated independently of the loss ranking. A scenario that produced a smaller loss but violated the lower or upper voltage bound would not be accepted as technically feasible [10]. In the historical case, the minimum documented 150-kV voltage is 148.091 kV, or 0.9873 pu, and is already within the adopted range. Because complete validated voltage outputs for the hypothetical cases are not available for publication, the study retains voltage as a modelling constraint but avoids reporting invented improvements [29, 30].

The decision rule selects the feasible candidate with the lowest calibrated loss. For the five tested alternatives this produces a clear numerical ranking, but the resolution is 25 MW and the result is sensitive to calibration. In particular, the 50- and 75-MW cases differ by only 0.010 MW. A finer search may identify a different minimum between the tested points, but such refinement should follow independent model validation to avoid false precision.

Numerical convergence does not establish complete operational suitability. A converged loss-minimizing case may still create branch or transformer overloads, insufficient N-1 security, impractical state-of-charge requirements, or unfavorable economics. The present method therefore answers a limited steady-state screening question and should be treated as an input to, rather than a replacement for, security-constrained and techno-economic planning.

2.5. Boundary conditions and model assumptions

The boundary conditions and technical assumptions are summarized in Tables 1 and 2. They distinguish the traceable historical Sulselrabar data from the hypothetical BESS operating scenarios.

Steady-state load-flow calculations use a Newton-Raphson formulation consistent with the published Sulselrabar model [12]. The historical operating state is used as the reference, and the Sungguminasa bus receives the specified BESS active-power injection. The voltage feasibility range is 0.95 - 1.05 pu.

Network topology, line and transformer parameters, generation dispatch, and load distribution remain unchanged across scenarios [31]. The BESS operates at unity power factor. Battery charging, energy duration, state-of-charge variation, converter losses, auxiliary consumption, degradation, and market dispatch are not included [32].

Table 1

Technical boundary conditions and parameters of the Sulselrabar case study.

Component	Parameter	Value
Study system	Network	Sulselrabar 150-kV interconnection
Historical snapshot	Date and time	21 May 2019, 15:00 WITA
Network model	Buses / lines	43 / 50
Generation fleet	Connected plants	21 units
Base transmission loss	Active loss	12.123 MW
Highest branch transfer	Tallasa-Sungguminasa	171.25 MW
Minimum 150-kV voltage	Palopo bus	148.091 kV (0.9873 pu)
Candidate BESS bus	Location	Sungguminasa 150 kV
BESS representation	Power factor	1.0 (active-power injection)
Voltage constraint	Operating range	0.95-1.05 pu
Load-flow method	Solver	Newton-Raphson

Table 2

Candidate BESS discharge-power scenarios.

Case	BESS Discharge Set-Point (MW)
Base case	0
Case 1	25
Case 2	50
Case 3	75
Case 4	100

3. Results and discussion

3.1. Scenario Performance

The calibrated Sulselrabar model was evaluated for the 0-MW reference and four candidate BESS discharge set-points at Sungguminasa. Active transmission loss is the primary comparison metric. The results are interpreted as a parametric response curve for one historical network snapshot rather than as output from a formal optimization algorithm.

Without BESS support, the reference transmission loss is 12.123 MW. A 25-MW discharge set-point reduces the calibrated loss to 11.664 MW, corresponding to a 3.78% reduction. At 50 MW, the loss decreases further to 11.435 MW. The minimum value of 11.425 MW is obtained at 75 MW, yielding a 5.76% reduction relative to the historical base case. The numerical results are summarized in Table 3.

Table 3

Calibrated transmission-loss response to the tested BESS discharge set-points.

Case	BESS (MW)	Loss (MW)	Reduction (%)
Base case	0	12.123	0.00
Case 1	25	11.664	3.78
Case 2	50	11.435	5.67
Case 3	75	11.425	5.76
Case 4	100	11.654	3.87

The reduction in total loss can be explained by power-flow redistribution. Local active-power injection at Sungguminasa reduces the portion of receiving-area demand supplied through some upstream paths, including the Tallasa-Sungguminasa corridor. The resulting current decrease lowers resistive I^2R losses on relieved branches. Because incremental power follows all electrically available paths according to impedance and operating angles, the magnitude of the system-wide benefit depends on both the injection location and the pre-existing flow pattern.

The marginal loss benefit declines as discharge increases. Moving from 0 to 25 MW reduces loss by 0.459 MW; the next 25-MW increment reduces it by a further 0.229 MW; and the increment from 50 to 75 MW reduces loss by only 0.010 MW. Thus, most of the observed loss benefit is already captured by 50 MW, while the additional improvement at 75 MW is very small.

This nonlinearity is consistent with the quadratic dependence of resistive losses on current. Initially, reducing current on a heavily loaded path can provide a strong benefit. As the path is relieved, the marginal I^2R saving decreases. At higher local injection, power-flow angles and alternative-path currents change, so additional BESS discharge can increase losses elsewhere even while the original corridor remains relieved. The total network loss is the sum of all branch contributions, not the loss of one corridor alone.

The reported percentages should be interpreted relative to the historical 12.123-MW loss, not relative to total generation or energy consumption. A 5.76% loss reduction means that 0.698 MW of instantaneous transmission loss is avoided at the modelled snapshot. It does not mean that system demand falls by 5.76% or that annual energy loss falls by the same percentage. Annual benefit would depend on how often comparable network conditions occur and how long the BESS can maintain the set-point.

Increasing discharge from 75 to 100 MW raises calibrated loss from 11.425 to 11.654 MW. The additional 25-MW injection therefore adds 0.229 MW of system loss relative to the 75-MW case. This reversal demonstrates that maximum BESS discharge is not automatically the best technical operating point for loss reduction under the modeled snapshot.

The 100-MW result is central to the study because it demonstrates that technical benefit is not proportional to installed or dispatched power. Relative to 75 MW, the additional 25-MW injection increases loss by 0.229 MW. The system has passed the minimum region represented by the discrete cases, and further discharge begins to impose a larger burden on alternative paths. This outcome cautions against selecting a converter rating solely because a larger device can inject more power.

The result does not imply that a 100-MW BESS would always be inferior. Installed converter rating and operating power should therefore be distinguished because the available power capability can also provide ancillary services under different operating conditions [11]. A larger converter could operate at 75 MW for loss minimization and reserve the remaining capability for contingency response, frequency regulation, or periods with different load and renewable patterns. Installed rating and operating set-point are separate decisions. The present result concerns the latter under one snapshot; economic justification of additional headroom requires valuing services that are outside the loss-only objective.

The comparison also shows why scenario transparency matters. If only the base and 100-MW cases were reported, the analysis would show a benefit of 0.469 MW but would miss the better performance at intermediate power. Conversely, reporting only the 75-MW case could suggest that benefit continues to grow with injection. The five-point curve reveals both the improvement region and the subsequent reversal, providing a more credible basis for refinement.

Calibration uncertainty is particularly important because the difference between the 50- and 75-MW cases is only 0.010 MW, or about 0.09% of the 75-MW loss value. The historical base loss comes from an earlier system representation, and the calibrated scenarios do not reproduce unknown meter errors, conductor-temperature effects, every transformer-loss setting, or all confidential dispatch parameters. Accordingly, 75 MW is reported as the numerical minimum of the tested set, while 50 MW is treated as a near-optimal alternative whose ranking could change under modest model uncertainty.

The historical minimum bus voltage of 0.9873 pu already satisfies the adopted operating range. Voltage is retained as a feasibility constraint rather than claimed as the primary source of benefit. Detailed voltage values for every BESS scenario require access to the complete validated ETAP model and updated PLN measurements; accordingly, this paper does not report unsupported scenario-specific voltage improvements.

This conservative treatment distinguishes evidence from expectation. Active injection near a receiving area may improve some local voltages by reducing upstream current and angle differences, but it can also increase voltage at the connection bus or alter reactive flows. Without complete scenario outputs, neither the magnitude nor the location of an improvement can be established. A future validated study should report minimum and maximum voltage, the buses at which they occur, and the voltage change at Sungguminasa for every set-point.

Equipment loading should likewise accompany future loss results. A lower total loss does not guarantee that every individual line and transformer remains within its thermal rating. Power redistribution may relieve the selected corridor while increasing flow on another element. Branch-loading tables, transformer loading, and N-1 contingency results would determine whether the 75-MW operating point is secure as well as efficient.

3.2. Sensitivity analysis

Sensitivity analysis was performed by varying only the BESS discharge set-point while retaining the same historical network condition. Loss response is non-monotonic: losses decline from 0 to 75 MW and rise at 100 MW. This is a one-factor parametric sensitivity analysis, not a probabilistic uncertainty study and not a multi-condition robustness analysis.

The marginal sequence is 0.459 MW avoided for 0-25 MW, 0.229 MW for 25-50 MW, 0.010 MW for 50-75 MW, and -0.229 MW for 75-100 MW. The final positive improvement is therefore much smaller than the preceding increments and is comparable to plausible calibration uncertainty.

The small 50-versus-75 MW difference means that transmission loss alone is insufficient for investment selection. A more robust comparison should include converter cost, MWh duration, round-trip efficiency, cycling duty, degradation, N-1 security, voltage/reactive support, network-deferral value, and ancillary-service revenue. Without these additional objectives, the present study cannot determine the economically optimal installed BESS rating.

Accordingly, 75 MW is the best tested discrete discharge set-point for the investigated loss-minimization screen, while 50 MW is a technically competitive near-optimal alternative. This wording replaces the stronger claim of mathematical optimization.

The marginal sequence provides a useful decision perspective. Moving from 0 to 25 MW avoids 0.459 MW of loss, the next 25-MW increment avoids a further 0.229 MW, and the increment from 50 to 75 MW avoids only 0.010 MW. The increment from 75 to 100 MW reverses the trend and adds 0.229 MW. These values show that most of the observed loss benefit is captured by 50 MW and that the final improvement obtained at 75 MW is very small relative to the additional power capability.

A difference of 0.010 MW between 50 and 75 MW is only about 0.09% of the corresponding loss value. Even modest uncertainty in branch resistance, load allocation, transformer taps, generation dispatch, or the base-case calibration could reverse their order. No statistical confidence interval can be calculated from a single deterministic historical snapshot; future work should use bounded parameter sensitivity or Monte Carlo sampling across uncertain network inputs.

Additional discharge levels would improve numerical resolution, for example 5- or 10-MW increments between 50 and 100 MW. However, a finer grid should be evaluated only after the base model is independently validated. Robustness should also be tested across multiple load levels, peak/off-peak conditions, renewable-output levels, seasons, balancing-generator choices, and charging cases.

Location sensitivity is also required. Repeating the same set-point comparison at selected generation buses, load centers, and high-transfer corridors would reveal whether Sungguminasa is locally or systemically attractive. Loss-sensitivity factors, PTDFs, OPF, or a metaheuristic location-sizing formulation could be used to shortlist or optimize candidate buses. The present manuscript therefore claims only a candidate-location evaluation.

3.3. Operational, energy, and planning implications

For operation, the principal implication is that a fixed maximum-discharge policy is not appropriate for transmission-

loss reduction. The preferred injection depends on contemporaneous load, generation, renewable output, topology, and balancing actions. The 75-MW result is a reference for conditions resembling the 2019 snapshot, not a permanent real-time command.

Energy sizing requires chronology. If the loss-reduction opportunity lasts for several hours, the usable MWh rating must sustain the selected discharge over that interval while respecting minimum and maximum state of charge [29]. Charging energy must be acquired at another time, and round-trip losses mean that more energy is consumed during charging than is later delivered. A loss-reduction service is economically sensible only when avoided network and system costs exceed charging, conversion, degradation, and opportunity costs.

A BESS may stack multiple services to improve utilization [11]. Capacity reserved for frequency response cannot always be simultaneously committed to a long loss-reduction discharge, and maintaining upward and downward reserve may require operation near an intermediate state of charge. Service stacking must therefore be represented through compatible power and energy constraints. Revenue cannot simply be added across services without checking whether the same converter and stored energy are being counted twice.

From a sustainability perspective, reducing instantaneous transmission loss decreases the generation required to serve a given load at that moment [2]. The corresponding emissions benefit depends on the marginal generating unit displaced by the battery and on the emissions associated with charging. If the BESS charges from curtailed renewable energy, the system effect may be favourable; if it charges from high-emission generation and later displaces cleaner generation, loss reduction alone does not guarantee lower emissions. Lifecycle impacts of battery manufacture, replacement, and end-of-life management should also be included in a comprehensive assessment.

A staged planning process is recommended. First, the historical model and current Sulsebar network should be independently validated. Second, multi-snapshot, multi-location, charging/discharging, and N-1 technical screening should be performed. Third, promising MW trajectories should be converted into MWh and converter requirements using chronological optimization. Finally, a techno-economic assessment should compare CAPEX, replacement, degradation, energy cost, ancillary-service revenue, avoided loss, reliability benefit, and network-deferral value.

Reliability assessment should test the candidate under credible N-1 outages. Loss reduction in the intact network may not persist when a transmission line, transformer, generating unit, or the BESS itself is unavailable. The storage converter may relieve an overloaded remaining path during one contingency but worsen another through flow redistribution. Security-constrained optimal power flow can incorporate these cases and identify a set-point that balances normal-operation efficiency with post-contingency feasibility [23].

No quantitative economic result is claimed in this study. The model provides an instantaneous MW loss difference at one timestamp, not annual MWh savings, revenue, NPV, or payback. A quantitative economic analysis requires

chronological operation with and without storage, BESS CAPEX and replacement assumptions, efficiency and degradation, electricity value, ancillary-service rules, and the duration/frequency of comparable network conditions.

The final investment decision should be based on robust performance rather than the smallest loss reported for one deterministic case. A candidate power and energy rating should remain technically feasible across representative operating years, retain value under plausible price and renewable scenarios, and satisfy utility security requirements. Decision criteria can include net present value, benefit-cost ratio, loss and congestion reduction, reliability contribution, emissions impact, and sensitivity to battery replacement [11]. Applying these criteria would place the 50- and 75-MW alternatives in a balanced planning context and reveal whether their small technical difference justifies a material difference in capital cost.

3.4. Limitations and future work

The study has several limitations. It uses one historical Sulsebar snapshot from 2019, a single candidate BESS location, five discrete discharge set-points, fixed non-BESS dispatch, unity-power-factor BESS operation, and a calibrated rather than independently revalidated network model. Charging, MWh duration, state of charge, converter losses, reactive-power control, degradation, chronology, contingencies, and economic performance are outside the modeled scope. The 50- and 75-MW cases are separated by only 0.010 MW, so the ranking should be considered sensitive to model uncertainty.

Future work should update and independently validate the 43-bus model using recent PLN data, compare the results with ETAP or another power-system tool, test additional discharge levels, evaluate multiple candidate locations, and include peak/off-peak and seasonal operating snapshots. Formal optimization using OPF, PSO, GA, differential evolution, or another suitable continuous/multi-objective approach can then be applied to location, MW rating, and MWh capacity. Chronological simulations should include demand and renewable uncertainty, charging schedules, state-of-charge limits, efficiency, and degradation, followed by quantitative techno-economic and uncertainty analyses.

Furthermore, dynamic and protection studies should assess frequency and voltage control, fault ride-through capability, harmonic performance, short-circuit contribution, and protection coordination [4, 10]. Finally, future models should adopt proper data governance by documenting assumptions, base quantities, and scenario transformations while protecting confidential utility data to ensure reproducibility and traceability of planning results.

4. Conclusion

This study presents a scenario-based evaluation of candidate BESS discharge set-points in the Sulsebar 150-kV interconnected system using a traceable historical 43-bus snapshot. The published reference case has 12.123 MW of transmission loss, a maximum reported branch transfer of 171.25 MW on the Tallasa-Sungguminasa corridor, and a minimum 150-kV voltage of 0.9873 pu. For a candidate BESS at Sungguminasa, the calibrated losses for 0, 25, 50, 75, and 100 MW are 12.123, 11.664, 11.435, 11.425, and 11.654 MW, respectively. The numerical minimum is therefore 75 MW, corresponding to a 5.76% loss reduction, but the 50-MW case is only 0.010 MW higher and captures nearly all of the observed

technical benefit. The rise in loss at 100 MW confirms a non-monotonic response caused by network power-flow redistribution. The scientific contribution is a transparent Indonesian case-study framework that distinguishes historical data, candidate-location assumptions, discrete scenario enumeration, and calibration uncertainty rather than claiming a new optimization algorithm. The finding is specific to one 2019 operating snapshot and does not establish a globally optimal BESS location, continuous set-point, MWh capacity, or economic optimum. Updated PLN validation, finer set-point screening, multi-location and multi-snapshot analysis, uncertainty assessment, security constraints, chronological MWh sizing, and formal techno-economic optimization are required before practical investment or operational decisions.

CRediT authorship contribution statement

Khusnul Khatimah Assagaf: Conceptualization, Methodology, Software, Formal analysis, Investigation, Writing - original draft. **Diva Mauliya:** Data curation, Validation, Visualization, Writing – review and editing.

Declaration of competing interest

No conflict of interest.

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Data availability

The historical Sulselrabar base data were obtained from published studies based on PLN/AP2B information. The calibrated BESS scenario data and processing method are available from the corresponding author upon reasonable request.

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