A Resilience Driven Multi-Objective Approach for Optimal Placement of Energy Storage in Islanded Transmission Networks

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2023 IEEE PES Innovative Smart Grid Technologies Latin America (ISGT-LA) | 979-8-3503-3696-2/23/$31.00 ©2023 IEEE | DOI: 10.1109/ISGT-LA56058.2023.10328327

***Abstract*— Battery energy storage systems can provide the needed supply during extreme events and improve system resilience during system outages caused by natural or man-made events. The amount of relief that energy storage can provide during an extreme event depends strongly on its placement and size. This study investigates the optimal sizing and placement of energy storage resources throughout island transmission networks to improve grid resilience. Three aspects of resilience were considered, namely (1) providing back up to critical loads under probable system contingencies, i.e., mitigating critical load drops due to grid outages, (i.e., consequential load drop), (2) mitigating the need to interrupt service to critical loads that can happen as a consequence of thermal and voltage grid violations under probable system contingencies (i.e., non-consequential critical load drops), and (3) enabling orderly breakup into smaller islands and subsequent operation of these system islands while maximizing the number of critical loads being served.**

***Index Terms*—Energy Storage, reliability, resilience.**

I. Introduction

System resilience is an encompassing topic involving multiple study disciplines and is heavily impacted by infrastructure assets, operating processes, and people. Resilience involves preparedness to withstand damage during a severe event and the ability to recover rapidly after the event. Energy storage is gaining widespread application in electric power systems.

While most of the research addressing sizing and placement of energy storage has focused on distribution networks, prominent articles have been published with a focus on transmission grids. For example, [1] proposes using utility scale energy storage to reduce line congestion and thermal violations in the Pacific Northwest transmission grid. Locations are obtained using an exhaustive search. Similarly, [2] proposes energy storage in conjunction with a STATCOM to reduce thermal violations in a generic transmission grid but use genetic algorithm as an optimization engine. Reference [3] quantifies the benefits of energy storage in a generic transmission grid with large amounts of wind generators, although the allocation is somewhat arbitrary. Similar approaches were proposed in [4] and [5], where the authors used optimum power flows to derive their conclusions, but the objectives only fully addressed security violation.

This paper addresses the problem of Battery Energy Storage System (BESS) placement to improve system resilience objectives within the transmission and sub-transmission system (≥38 kV) in Puerto Rico. This study was conducted using the available information and prior analysis of grid vulnerabilities. Additionally, the paper provides an indicative view of locations within the grid where energy storage can improve system resilience.

Optimal ES placement throughout the system to improve system resilience was investigated by examining a set of known system vulnerabilities in the transmission and sub-transmission grid. This study focuses on using energy storage to mitigate four types of vulnerabilities:

- Improving the resilience of commercial and industrial (C&I) customers served by the 38-kV system
- Addressing 115kV bulk transmission grid reliability vulnerabilities
- Improving the resilience of substations
- Enabling orderly system islanding under extreme events to continue serving critical loads

II. Problem Definition and Overall Strategy

The transmission system in Puerto Rico consists of a meshed 230-kV network as well as a similarly meshed 115-kV. The system also comprises a highly diverse 38-kV sub-transmission network. Table I summarizes the system and Fig. 1 illustrates the grid. Most of the load centers are in the north of the island and are supplied at distribution voltage levels through substations connected to either the 115-kV or 38-kV. While one of the larger oil-fired generation plants is near the load centers, most of them are in the south of the island, resulting in a predominant northbound flow of power.

A thorough analysis of the meshed transmission system revealed a number of credible contingencies that can impact the system, and these were selected to conduct this study. Consequently, the study further used the list of major transmission circuits for each voltage level for multi-contingency outages. Their names are omitted.

TABLE I. Transmission Line Information

Transmission Lines	Line / segment count	Length [miles]
38-kV	185 / 285	1,563
115-kV	46 / 99	711
230-kV	12 / 18	424
Total	243 / 402	2,698

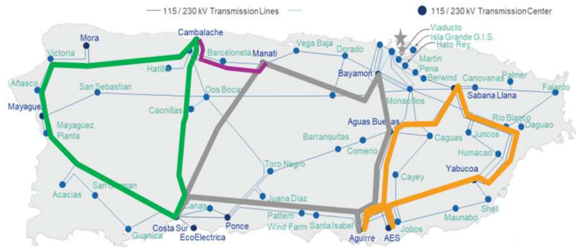

Figure 1. Puerto Rico transmission system.

A. Critical Load Reliability

A thorough review of all transmission or sub-transmission-connected critical loads such as hospitals, water treatment facilities, airports, etc., was conducted to determine their distribution per area. A total of 248 critical loads were identified, which are supplied by 224 electrical buses. These buses serve a total of 904 MW. To conduct the analysis, the system was divided into eight operational areas, a distribution that enables quantifying transfer capabilities among these various areas. This division facilitates reference in the Integrated Resource Plan that is under development, as well as in filings with the regulator. These areas were created with input from the various teams based on their experience. Once the areas are determined, we traced the critical loads across the areas, as presented in Table II.

TABLE II. CRITICAL LOAD DISTRIBUTION PER AREA

Area	Critical Loads	Number of Buses	Base Load [MW]
1	37	36	100.6
2	25	23	88.5
3	47	42	219.7
4	15	14	36.2
5	42	36	126.3
6	19	18	60.4
7	21	21	103.7
8	42	34	168.1
Total	**248**	**224**	**904.4**

This information was parsed and formed into a table to associate C&I prioritization and critical infrastructures. This information provides each load loss' sub-area and area. The classification of each load loss is presented based on the importance of these loads. Historical outage data for a period of two years was used to determine the reliability indices, such as Mean Time To Repair (MTTR) in hours per outage (hours/outage) and failure rate in occurrence per year (oc/yr). The MTTR and failure rate for each bus corresponds to the transmission line that causes the largest load loss at that bus and these two pieces of information are used to determine the expected energy not served (EENS) associated with a load loss. For example, a 10 MW loss that occurs two times per year with an MTTR of 2.5 hours results in 50 MWh of energy not served to customers over one year.

B. BESS Placement to Improve Reliability to C&I Customers connected to Sub-Transmission

The first objective is to evaluate the 38-kV grid to identify the optimal locations for integrating BESS projects to increase the reliability of the most vulnerable C&I clusters. This analysis considers existing information on the transmission line reliability index, operational flexibility, redundancy, and EENS due to line outages. The study uses a sequence of power flows, consecutive contingency analysis, and an optimal dispatch process to determine the location and amount of BESS needed at various substations, improving system resilience and resulting in the smallest load loss. The process is outlined in the flowchart depicted in Fig. 2.

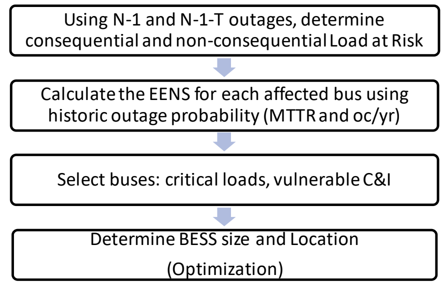

Figure 2. Study procedure flowchart for the first objective.

The study process commences with the N-1 outage study and extends with the second series of outages, that is, N-1-T, where outage "T" denotes an outage of the specific transmission line under investigation. The outages considered under N-1 include credible outages typically considered in transmission planning studies, such as NERC TPL-004 standard compliance [6].

To achieve this objective, 1,568 transmission outages were considered and simulated. For the study of the 38-kV system, all transmission lines operating at 38 kV are considered. The multiple outage study N-1-T is considered an extreme but credible case, resulting in 154,000 multi-contingency outages that were simulated and investigated. To determine the impact of the 38-kV system outage, the amount of load loss associated with the outage is calculated using power-flow simulations. The incremental load drop associated with each T outage at electrical buses throughout the system is determined.

As described earlier, 224 buses throughout the system have critical loads and are distributed across eight areas and 20 sub-areas. Using the process outlined above, the load losses at various buses with critical loads were determined. Table III provides the results for eight substations with critical loads.

TABLE III. LOAD LOSS PARAMETERS

Bus	Voltage Level	Consequential			Nonconsequential			Reliability			EENS (MWhr)
		Load at Risk (N-1)	Load at Risk (N-1-T)	Number of Outages	Load at Risk (N-1)	Load at Risk (N-1-T)	Number of Outages	Load at Risk (MW)	MTTR (hr)	Outage Rate (oc/yr)	
1	38	0.0	0	0	7.7	0.4	52	8.1	33	1.24	329
2	38	0.0	0	0	7.0	8.3	49	15	33	1.24	621
3	38	7.4	0	0	4.3	3.1	43	7.4	3.9	8.71	250
4	38	0.0	0	0	1.4	6.2	4	7.6	17	2.07	266
5	38	0.0	9.3	1	0.0	0	0	9.3	17	11.4	1789
6	38	0.0	5.6	1	0.0	0	0	5.6	17	11.4	1081
7	38	0.0	6.8	2	0.0	0	0	6.8	13	11.3	976
8	38	0.0	14	1	0.0	0	0	14	6.6	10.4	954

The study indicates that 57% of critical loads are vulnerable to consequential load loss due to the outage of one or two transmission lines. Of the total 904 MW of critical load, 339 MW (38%) are vulnerable to one line outage, and 295 MW (33%) are vulnerable to two transmission line outages.

Regarding the non-consequential load interrupted to resolve system overloads, 242 MW (16%) should be interrupted to mitigate the overloads caused by a single transmission line outage, and 18 MW (2%) should be interrupted to mitigate the overloads caused by multiple transmission line outages.

The size and location of the BES to mitigate the loss of critical loads using the load-loss matrix were determined using the following risk prioritization criteria:

1. BESS potential locations are limited to critical loads.
2. BESS is only considered for outages that last less than 5 hours, that is, MTTR less than 5 hours per outage.
3. BESS is considered for loads 10 MW and larger.

TABLE IV. OPTIMUM BESS SIZE AND SITE FOR CRITICAL LOAD RELIABILITY

Bus	Voltage Level	Base Load (MW)	Load at Risk (N-1)	Load at Risk (N-1-T)	Load at Risk (MW)	MTTR (hr)	Outage Rate (oc/yr)	EENS (MWhr)
1	38	19	0	19	39	1	5	180
2	13	28	28	0	28	4	7	649
3	38	27	0	27	27	4	2	215
4	38	22	22	0	22	4	7	511
5	38	22	0	22	22	3	7	478
6	38	16	0	16	16	4	14	932
7	38	12	0	12	12	4	9	439
8	13	12	12	0	12	4	7	276
9	38	12	12	0	12	4	7	272
10	38	11	0	11	11	2	2	64
11	38	11	0	11	11	1	7	84
12	38	11	11	0	11	4	7	252
13	38	11	11	0	11	4	7	249
14	38	10	10	0	10	4	7	243
15	38	10	10	0	10	4	7	240
Total		234	115	118	253			5084

The largest load loss associated with each electrical bus throughout the system was determined using the above criteria. Table IV lists 16 buses identified and proposed for BESS installation to address the largest critical load losses, prioritized on the associated MW load at risk. In total, 234 MW BESS are proposed to be installed at 15 locations, 13 at 38 kV and two at 13 kV. The proposed BESS MW and MWh at each location should match the load at risk and the MTTR of the respective location. For example, for the BESS in bus 13, a 11 MW, 4 hr BESS system is recommended (the BESS should be rated to meet the Load at Risk in MW and the MTTR). This BESS, along with the other 15 proposed BESs, will address the largest critical load at risk throughout the system.

C. BESS Placement to Minimize Security Violations at 115kV

The previous subsection recommended 16 BESS locations that address the loss of the largest critical loads throughout the system. The recommendation was limited to non-consequential load loss. The proposed BESS did not provide relief for consequential load loss, and its mitigation is limited to addressing post-outage overloads.

The scope of this section is to eliminate load at risk highlighted in the load-loss matrix (Table III). This objective can be theoretically accomplished using an optimal dispatch algorithm. The security-constrained dispatch (SCD) [7] integral to the TARA [9] software procedure can effectively determine the optimal amount of additional generation at various buses needed to eliminate the load loss. The location and size of generation dictate the required BESS to enhance system resilience under the considered extreme outages, such as multiple outages. Though the above-unconstrained procedure meets the objective, the number of BES units will be significant, and locations will be unpractical. An unconstrained optimization will address 141.9 MW non-consequential and 339.3 MW consequential load losses. However, one must install a myriad of BESS units of various sizes throughout the system to achieve this solution.

The optimization process is constrained as follows to achieve practical and implementable results:

1. BES locations are limited to buses with EENS > 200 MWh.
2. The maximum outage duration is 5 hours.
3. At least one bus should be in each area.

Using these three criteria, nine 38 kV substations were identified for the optimization input, and an additional 26 were selected due to their criticality as identified by system operations, totaling 35. The optimization process to minimize the load at risk throughout the system was conducted using the SCD process to determine the size of the necessary generation with three constraints. Moreover, the additional generation size was considered not to exceed 100 MW. Applying these constraints resulted in an optimal reduction of the load at risk instead of elimination. Unless reported, it is assumed that the BESS duration is 5 hours. The results of the SCD optimization for the nine substations are presented in Table V. As the results indicate, a total of 608 MW BES storage is recommended to reduce load at risk throughout the system, and the locations are limited to critical loads. Four of the nine locations are 115 kV, and five are 38 kV critical buses. This alternative addresses 109.2 MW of 141.9 MW non-consequential load loss and 94.6 MW of 339.3 MW consequential load loss. The results for other substations are omitted for conciseness. The above-proposed solution minimizes the load at risk throughout the system using a BESS solution. The remaining issues, such as outages longer than 5 hours or the remaining critical loads that could not be addressed due to the study constraints, cannot be addressed with BESS, and more suitable mitigation measures should be considered.

TABLE V. SCD OPTIMIZATION RESULTS FOR NINE SUBSTATIONS

Bus	Voltage (kV)	BESS (MW)	Duration (hr)	Critical Load / C&I / Not Critical
1	38	58.4	2.9	Critical Load and C&I
2	115	83.5	4.8	Critical Load and C&I
3	38	29.7	1.8	Critical Load and C&I
4	38	100	4.2	Critical Load and C&I
5	115	96.1	4.3	Critical Load and C&I
6	115	26.7	2.9	Critical Load and C&I
7	115	72.7	3.8	Critical Load and C&I
8	38	73.2	4.6	Critical Load and C&I
9	38	67.8	3.6	Critical Load and C&I

	Total	608.1		

D. BESS Placement to Enable Orderly System Islanding

Under extreme scenarios where the grid cannot be kept connected and must be divided into independent electrical islands, operating these islands reliably is crucial to continue serving critical loads. Once an electrical island is formed, one cannot expect that there is always enough power generation to meet all demands within the island. As a minimum requirement, the electrical island must serve all its critical loads until it is reconnected to the grid. During islanding times, storage can play an important role in maintaining the supply-demand balance. The larger the generation deficit is in an island, the higher the needed storage capacity. However, there are two important considerations to maintain this balance:

- For economic reasons, the storage must be useful even in normal conditions (i.e., the grid is still intact). That is, storage cannot stay idle and only operate under rare conditions (islanding).
- The islanding scenarios are not unique, and the grid division into islands does not follow the same pattern depending on the causing event. One cannot expect the same island to form under a hurricane or flood. Therefore, there are many ways for the grid to divide into islands. The storage locations must work for various island situations, not just one.

The number of BESS and their locations are determined by solving an optimization problem involving an objective function (costs to be minimized) and a set of constraints. The objective function consists of three components: 1) the cost of BESS installation, 2) the cost of an unserved load, and 3) the network upgrade cost. Conceivably, as more batteries are deployed, more electrical loads can be served during islanding, and fewer lines will need to be upgraded (as a battery can serve local load during peak times, thus resolving line-overloading issues). More batteries mean higher investment costs but provide more benefits as more load can be served during an emergency while deferring the wire-solution expenditure. Hence, the optimization process aims to find the battery sizes and locations that yield the smallest total cost.

The following assumptions are made for the cost components in the objective function:

1. BES costs obtained through market research are \$250/kW and \$300/kWh.
2. The value of lost load (VoLL) is \$57,940/MWh, as proposed in [8].
3. For transmission-line upgrade costs, the values (expressed in \$/MVA) depend on the particular lines and were obtained from previous projects of the utility.

The decision variables are as follows: 1) the investment amount (i.e., MW and MWh for batteries to be installed at a list of locations) and 2) the operational variables (i.e., output from conventional generators, MWh curtailment at load buses, line flows, BESS charge/discharge, and their state of charge). The constraints are grouped into 1) upper and lower bounds for the grid operational variables, such as line flows and generator output and load, and 2) battery operational constraints (charge, discharge, and SOC). The Puerto Rico grid consists of eight areas. Table VI shows each area's critical load data, non-critical load data, and total generation capacity. The table indicates that, if islanded, Areas 3 and 4 have severe generation deficits. Area 3 only has 26 MW of generation capacity while it must serve a critical load of 220 MW; Area 4 has a generation capacity of 23 MW and a total critical load of 36 MW. Batteries need to be in these two areas if they are to operate as electrical islands.

TABLE VI. LOAD AND GENERATION BY AREA

	Critical Loads		Other Loads		Dispatchable Generation	
Area	#	MW	#	MW	#	Pmax
1	37	101	60	177	2	165
2	25	89	82	272	5	300
3	47	220	98	218	2	26
4	15	36	61	231	2	23
5	42	126	48	119	4	232
6	19	60	38	89	6	833
7	21	104	55	120	4	985
8	42	168	122	485	6	610
Total	248	904	564	1710	31	3173

There are many ways to divide the grid into islands. In this study, we focus on two scenarios:

- Scenario 1 – The system is intact. The conditions for the optimization process are so that 1) both critical loads and other loads can be served, and 2) overloads on the transmission lines can be mitigated.
- Scenario 2 – The grid has been broken up into eight islands along their boundaries (i.e., each area is islanded from each other). The conditions for the optimization process are so that 1) only critical loads need to be served and 2) overloads on the transmission lines that remain in service can be avoided.

Table VII summarizes the (thermal) overload on the grid for each scenario before batteries are attempted. The data come from a PSS/E power-flow simulation at peak load. In addition, the TARA was used to produce the Line Outage Distribution Factors (DFAX) [10] matrices (one matrix for scenario 1 and eight matrices for scenario 2). The DFAX matrix provides information about how much (or sensitivity) a line overload can be reduced by injecting MW at a particular bus. The optimization process employs DFAX matrices to place batteries to mitigate line overloads.

TABLE VII. GRID OVERLOAD (BEFORE BESS DEPLOYMENT)

Scenario	Area	Overload #	Overload Min	Overload Max	Overload Ave
1	Intact	218	1.01	1.79	1.21
2	1	13	1.02	1.02	1.02
2	2	19	1.03	1.76	1.31
2	3	4	1.13	1.77	1.47
2	4	15	1.01	1.24	1.04
2	5	26	1.01	3.08	1.28
2	6	33	1.14	2.94	1.84
2	7	27	1.02	1.23	1.15

The buses present in DFAX matrices are treated as candidate buses for battery placement. Long-duration batteries are needed in many cases because the optimization process considers 24 hours of (critical) load support after islands form. While most batteries with less than a 24-hour duration are sufficient, one bus, some buses require BESS greater than 24 hours. To judge whether the recommended battery sizes are practical, inspecting the amount of unsupported load (that is, the amount of critical load that must drop) and the transmission line overloads are necessary. Table VIII summarizes the role of batteries in mitigating line overload. Compared with Table VII, batteries evidently can reduce the number of line overloads in the intact and the islanding scenarios.

TABLE VIII. INCREMENTAL IMPACT OF BESS ON GRID OVERLOAD

Scenario	Area	Overload #	Overload Min	Overload Max	Overload Ave
1	Intact	28 ↓	101% ↔	145% ↓	118% ↓
2	1	14 ↑	102% ↔	113% ↑	103% ↔
2	2	0 ↓			
2	3	1 ↓	130% ↑	130% ↓	130% ↓
2	4	0 ↓			
2	5	6 ↓	101% ↔	307% ↔	150% ↑
2	6	2 ↓	138% ↑	138% ↓	138% ↓
2	7	3 ↓	118% ↑	118% ↓	118% ↑

These results demonstrate how well batteries serve two purposes: support critical loads during islanding and alleviate transmission line overloading (regardless of islanding or not). Determining battery sizes and locations were performed using an optimization process, which means a compromise of competing interests. To better understand why battery sizes are relatively small compared to those found in previous tasks:

- While it is logical to expect that many batteries will be placed in Areas 3 and 4 due to their generation deficit, the optimization places only a moderate amount, resulting in the critical load being dropped. This may seem irrational, but it makes sense based on the economics of load (VoLL=$57,940/MWh) and current battery costs. If we place a much higher value for the load, the optimization process will find placing more batteries more economical.
- Area 6 has plenty of generation but also many line overloads. Batteries installed in this area are not used to serve critical loads but to mitigate line overloads. That is, by including the cost of grid upgrades in the optimization process, it is found that the battery solution can be more economical than grid upgrades.

III. CONCLUSIONS

This paper proposed a three-objective optimization method to size and allocate energy storage in a transmission grid with a focus on the islanded Puerto Rico network. These three objective functions were (1) minimize consequential and non-consequential loss of 38kV-connected critical loads, (2) minimize thermal overloads in the 115kV transmission network, and (3) enable orderly islanding during major outage events. Even though the three tasks use the same data set, they deviate in their findings regarding battery sizes and locations. One key reason is the economic value assigned to critical loads, namely VOLL=$57,940/MWh as proposed in [8]. This results in the third optimization objective accepting load drop, whereas objectives 1 and 2 implicitly assuming that critical loads must always be served.

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