DG Siting and Sizing Considering Energy Vulnerability

Project Lead: Fran Li (UTK) **Graduate Students and Research faculty/associates:** Chenchen Li (UTK)
Project Duration: 10/2024 – 12/2025
Funding Source: DOE – EARNEST, Stanford University

Summary

This project aims to develop a generalized approach for distributed generator (DG) siting and sizing to improve system resilience and reduce energy vulnerability. However, a key challenge lies in the lack of a general metric to quantify energy vulnerability in power systems. Additionally, incorporating energy vulnerability into DG planning models remains a challenge.

This year, the proposed resilience-oriented DG siting and sizing approach with energy vulnerability constraints (EVCs), developed in our previous study, is applied to a larger system (i.e., IEEE 123-bus system) to demonstrate its scalability. The expected load shedding index (ELSI), defined as the ratio of the load shedding to the original load, is calculated for each community. Moreover, a violation variable is introduced to ensure model feasibility. Based on this formulation, a sensitivity analysis is conducted on the weights in the cost coefficient of the violation variable associated with low-income communities.

The results show that, when energy vulnerability is considered, DG units tend to be installed at buses with low-income communities or with a heavy average load. This leads to a relatively large percentage reduction in ELSI for these communities, demonstrating that the proposed approach can simultaneously improve system resilience and reduce energy vulnerability. In addition, DG installation strategies and corresponding ELSI under different EVCs are presented in TABLE I and Figure 1, while the results under different weights in cost coefficients of violation variable corresponding to low-income communities are shown in TABLE II and Figure 2. According to these results, the following generalized guidelines can be concluded.

(1) An effective method to satisfy a stricter EVC is to install DG units in proximity of where the low-income communities are located.

(2) Under a tighter EVC, the difference in the ELSI among different income communities is smaller, and the ELSI of all communities remains at a relatively low level. Additionally, there is a higher energy vulnerability cost with respect to the reference case of no EVC considered, and a greater share (%) of this cost in the expected cost of unserved load.

(3) Placing excessive emphasis on minimizing the ELSI for low-income communities can lead to higher ELSI values for other non-low-income communities. This overreaction does not contribute to reducing the energy vulnerability of the power system.

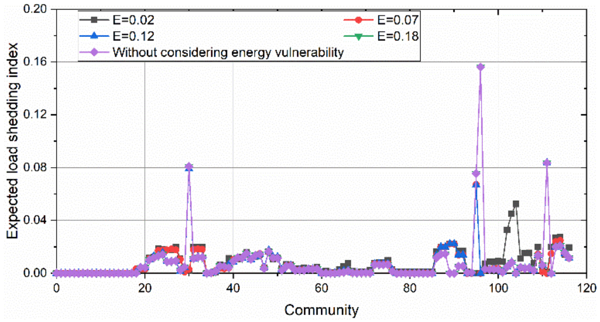

Figure 1: ELSI of the IEEE 123-bus system under different EVCs

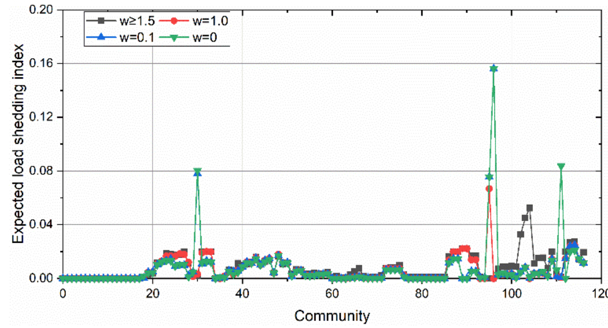

Figure 2: ELSI of the IEEE 123-bus system under different weights in cost coefficients of violation variable corresponding to low-income communities

TABLE I: Results of the IEEE 123-bus System Under Different EVCs.

Cases	DG unit bus (#)	Rated power of DG units (MW)	Energy equity cost ($)	Energy equity cost / Expected costs of unserved load
$\boldsymbol{E}$=0.02	30, 51, 77, 95, 96, 111	3.0, 3.0, 3.0, 3.0, 1.9, 3.0	2985	37.17%
$\boldsymbol{E}$=0.07	30, 51, 77, 96, 104, 111	3.0, 3.0, 2.8, 3.0, 2.7, 2.4	1100	17.90%
$\boldsymbol{E}$=0.12	28, 51, 77, 96, 104, 112	3.0, 3.0, 2.8, 3.0, 2.1, 3.0	625	11.02%
$\boldsymbol{E}$=0.18	28, 51, 77, 89, 104, 112	3.0, 3.0, 3.0, 3.0, 1.9, 3.0	0	0
EVC is not considered (i.e., $\boldsymbol{E} = \infty$)	28, 51, 77, 89, 104, 112	3.0, 3.0, 3.0, 3.0, 1.9, 3.0	0 (ref. case)	0 (ref. case)

Note: Bus numbers in green indicate low-income community buses.

TABLE II: Results of the IEEE 123-bus System Under Different Weights in Cost Coefficients of the Violation Variable Corresponding to Low-income Communities.

Cases	DG unit bus (#)	Rated power of DG units (MW)	Energy vulnerability cost ($)	Energy vulnerability cost / Expected costs of unserved load
$w \geq 1.5$	30, 51, 77, 95, 96, 111	3.0, 3.0, 3.0, 3.0, 1.9, 3.0	2985	37.17%
$w = 1.0$	30, 51, 77, 96, 104, 111	3.0, 3.0, 2.8, 3.0, 2.7, 2.4	1100	17.90%
$w = 0.1$	28, 51, 77, 89, 104, 111	3.0, 3.0, 2.8, 3.0, 2.7, 2.4	15	0.30%
$w = 0$	28, 51, 77, 89, 104, 112	3.0, 3.0, 3.0, 3.0, 1.9, 3.0	0 (ref. case)	0 (ref. case)

Note: Bus numbers in green indicate low-income community buses.

Mitigation of Circular Flows in HVDC-Integrated Transmission Systems

Project Lead: Fran Li (UTK) **Graduate Students and Research faculty/associates:** Chenchen Li (UTK)
Project Duration: 10/2024 – 4/2026
Funding Source: National Laboratory of the Rockies (NLR)

<u>Summary</u>

This project aims to develop a market clearing approach that incorporates for marginal loss price and mitigates the circular flows in HVDC-integrated transmission systems. Circular flows refer to abnormal loop flows between HVDC and AC lines, driven by negative generation offers, inaccurate power losses modeling, and binding transmission constraints. These flows may lead to operational and stability concerns in transmission systems. In addition, the proposed strategy must be seamlessly integrated into existing ISO/RTO market clearing frameworks, which are integrated with established operational procedures, regulatory requirements, and software infrastructure. In this context, an optimization-based strategy is developed to enhance the current market framework and effectively mitigate circular flow issues.

The framework of the optimization-based strategy for mitigating circular flows is illustrated in Fig. 1. It consists of two main steps: HVDC power flow determination and market clearing.

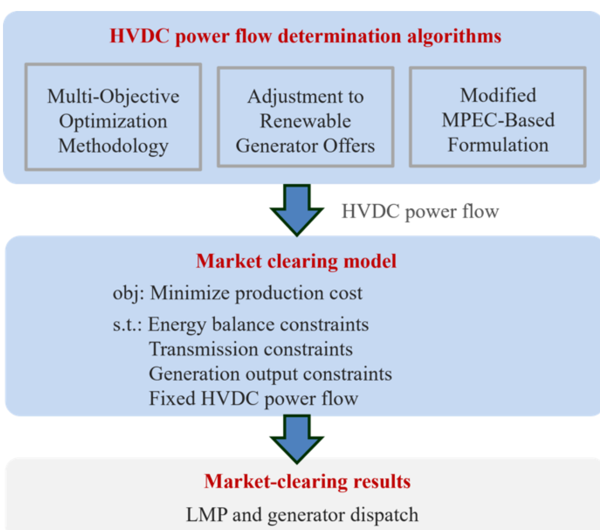

Figure 1: The framework of optimization-based strategy for mitigating circular flows

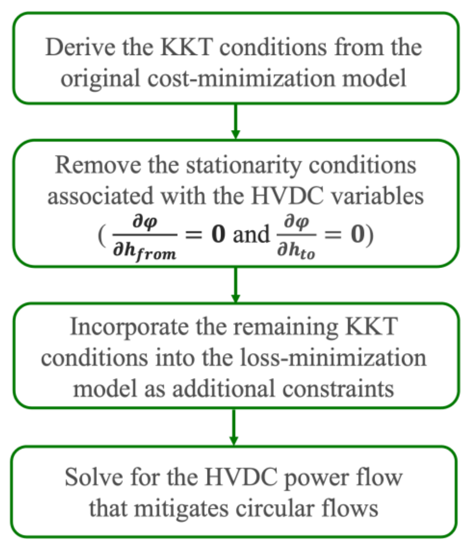

Figure 2: The framework of modified MPEC-based formulations

Several algorithms are proposed to determine HVDC power flows, including a multi-objective optimization methodology, an adjustment to renewable generator offers, and a modified mathematical program with equilibrium constraints (MPEC) based formulation. The multi-objective optimization methodology replaces the objective function in the original market clearing model with a weighted sum of production costs and system losses. The adjustment to renewable generator offers removes subsidies for renewable generators, resulting in positive generation cost coefficients and preventing the artificial maximization of system losses. The modified MPEC-based formulation, as shown in Fig. 2, incorporates selected KKT conditions derived from the original cost-minimization model (excluding the stationarity conditions associated with HVDC variables) into a loss-minimization model as additional constraints. Solving these models yields HVDC power flows that avoid inducing circular flows. In the second step, the determined HVDC power flows are fixed in the ISO/RTO market clearing model, which is then solved to obtain the final locational marginal prices and generator dispatch.

The effectiveness of the proposed strategy is validated on a modified reliability test system developed by the National Laboratory of the Rockies (NLR), with case studies implemented in NLR's Sienna platform. The results of different algorithms under scenarios without and with binding transmission constraints are summarized in Table 1, from which the following conclusions can be drawn:

(1) The multi-objective optimization methodology and the modified MPEC-based formulation effectively mitigate circular flows under both binding and non-binding transmission constraints. By explicitly considering system losses, the resulting HVDC power flow is below the critical threshold that does not induce circular flows.

(2) The multi-objective optimization methodology achieves a relatively higher HVDC utilization rate, while the modified MPEC-based formulation leads to lower systems losses.

(3) The adjustment to renewable generator offers mitigates circular flows only in the scenario without binding transmission constraints.

Overall, the proposed strategy provides system operators with a practical and flexible approach to mitigate circular flows in market clearing for HVDC-integrated transmission systems.

Table 1: Results of different algorithms in different scenarios

Algorithms	Without binding transmission constraints				With a binding transmission constraint			
	HVDC power flow (MW)	Production cost ($)	System loss (MW)	Circular flow (yes or no)?	HVDC power flow (MW)	Production cost ($)	System loss (MW)	Circular flow (yes or no)?
Cost-minimization	1218.96	93485.57	158.43	yes	1311.29	93489.25	175.11	yes
Loss-minimization	102.59	93503.22	44.02	no	102.59	93509.59	38.32	no
Enumeration method	480.00	93501.92	51.67	no	500.00	93507.26	48.27	no
Multi-objective optimization methodology	227.61	93503.55	42.05	no	267.56	93509.27	37.36	no
Adjustment to renewable generator offers	193.78	93503.54	42.11	no	593.07	93506.01	56.19	yes
Modified MPEC-based formulation	216.17	93503.56	42.03	no	204.30	93509.51	36.81	no

Resilience-Oriented Scenario Reduction and Assessment under Extreme Events

Project Lead: Fran Li (UTK) **Graduate Students and Research faculty/associates:** Junjie Yin (UTK), Chenchen Li (UTK)
Project Duration: 10/2024 to 12/2025
Funding Source: DOE – EARNEST, Stanford University

Summary

The objective of this research is to develop a resilience-oriented scenario generation, reduction, and assessment framework for power systems under climate-driven extreme events. With the increasing frequency and severity of events such as torrential rainfall, hurricanes, and wildfires, conventional contingency analysis based on limited N–1 or predefined N–k conditions is no longer sufficient. Extreme events often induce spatially correlated outages and cascading failures, resulting in complex system responses that cannot be captured by traditional deterministic approaches. This study aims to establish a scalable framework that integrates probabilistic scenario generation, impact-based reduction, and multi-timescale assessment to enable efficient and accurate resilience evaluation.

As illustrated in Fig. 1, extreme events such as torrential rainfall can produce multiple potential hazard tracks, each associated with a distinct spatial footprint of system disruptions. These tracks define impacted zones, within which transmission and distribution assets may experience simultaneous outages. Unlike independent contingency assumptions, such geographically correlated failures significantly increase system vulnerability and can trigger large-scale disruptions. The proposed framework models these events by combining hazard trajectory representation with probabilistic failure mechanisms, enabling the generation of realistic large-scale N–k outage scenarios that capture both spatial dependency and uncertainty.

To address the computational challenges of massive scenario sets, a Monte Carlo-based scenario generation approach is adopted, followed by a two-stage assessment process. First, a static assessment layer performs rapid screening using steady-state power flow to evaluate key metrics such as load shedding, line loading, and voltage violations, thereby identifying high-impact scenarios and significantly reducing the candidate set. However, static metrics alone are insufficient to capture system resilience, especially in systems with high penetration of inverter-based resources. Therefore, selected scenarios undergo dynamic assessment through time-domain simulations to quantify transient stability metrics, including frequency deviation, RoCoF, and frequency nadir. This integrated evaluation ensures that scenarios with critical dynamic instability risks are retained, even if their steady-state impacts are moderate.

As shown in Fig. 2, a hybrid Monte Carlo–VAE–K-Medoids framework is proposed to extract representative scenarios from the reduced set. For each scenario, a feature vector is constructed by combining static and dynamic performance indicators, capturing both operational stress and stability characteristics. A Variational Autoencoder (VAE) is then employed to learn a compact latent representation of the high-dimensional feature space, preserving the intrinsic structure and similarity among scenarios. Subsequently, K-Medoids clustering is applied in the latent space to identify representative scenarios (medoids), ensuring that selected cases are physically meaningful

and robust to outliers. This approach enables a significant reduction in scenario size while maintaining the diversity and fidelity of system responses.

This research highlights the importance of jointly considering extreme-event characteristics, system vulnerability, and resilience metrics within a unified framework. By integrating probabilistic modeling, physics-based simulation, and data-driven learning, the proposed methodology provides an efficient pathway for identifying critical contingencies and evaluating system performance under extreme conditions.

In addressing future challenges, this study identifies several key research directions, including the incorporation of climate-informed failure models, improved representation of inverter-based resources, and the integration of physics-informed and data-driven approaches. Overall, this work contributes to the development of a scalable and adaptive resilience assessment framework for future power systems.

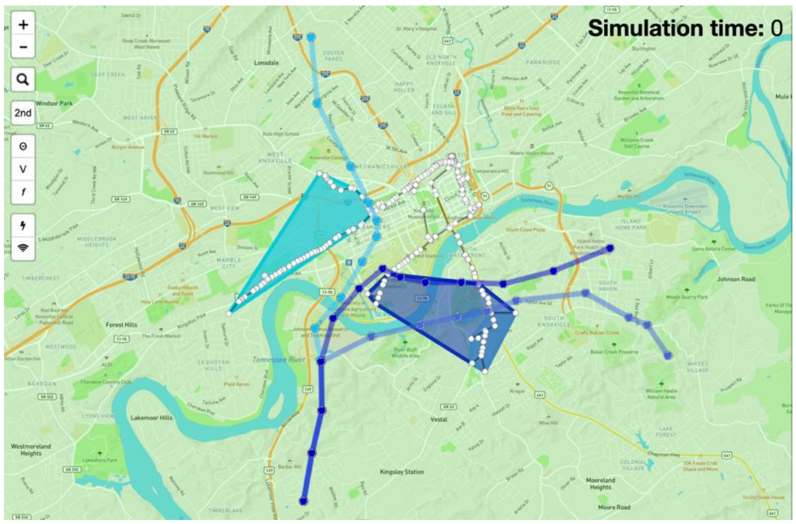

Fig. 1. Illustration of torrential rainfall potential tracks and the corresponding impacted zones.

Algorithm 1 Monte Carlo–VAE–K-Medoids for Representative Scenario Extraction

```
Initialize line failure probabilities {p_ij} and convergence tolerance ε
Set sample size S ← 1000, previous estimate L̂^prev ← ∅, and dataset D ← ∅
while not converged do
    Generate S outage scenarios via Monte Carlo simulation
    for each scenario s = 1, ..., S do
        Determine outage topology and extract topology-based features
        Run power flow under the sampled outage condition
        Compute scenario features x_s, including load shed, maximum line loading, minimum voltage, imbalance, available
        inertia, RES penetration, and location encoding
    end for
    Update dataset D ← D ∪ {x_s}_{s=1}^S
    Estimate expected load shed L̂ ← (1/S) Σ_{s=1}^S L_s
    if L̂^prev ≠ ∅ and |L̂ − L̂^prev| / L̂ < ε then
        Stop Monte Carlo simulation
    else
        Set L̂^prev ← L̂ and update S ← 2S
    end if
end while
Normalize feature vectors in dataset D
Train a variational autoencoder (VAE) using D
Encoder maps scenario feature x to latent parameters (μ, σ) and samples latent vector z = μ + σξ, where ξ ~ N(0, I)
Decoder reconstructs x̂, and VAE parameters are optimized using reconstruction loss and KL divergence
Obtain latent representations Z = {z_i} for all scenarios
Apply K-Medoids clustering in latent space by minimizing Σ_i d(z_i, z_m(k))
Select medoid scenarios as representative scenarios
return Representative scenarios and corresponding feature vectors
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Fig. 2. Monte Carlo–VAE–K-Medoids Algorithm for Representative Scenario Extraction

ADMM-based Virtual Inertia Scheduling (VIS) to Preserve Privacy in Networked Microgrids

Project Lead: Fran Li (UTK) **Graduate Students and Research faculty/associates:** Vince Wilson (UTK)
Project Duration: 2/2024 – 10/2025
Funding Source: ORNL

Summary

The objective of this project was two-fold. The first is to further develop an existing virtual inertia scheduling (VIS) economic dispatch mixed-integer linear program to enable multiple microgrid (MG) coordination and study inertia sharing between microgrids. The second objective is to use the multi-microgrid VIS to examine how different data sharing regimes between microgrids effects both internal control and the stability of multiple MG. The multi-MG VIS is solved using Gurobi while time domain simulations for dynamic verification and study are carried out using CURENT's ANDES platform.

The project consisted of three main tasks. The first was to expand the existing VIS formulation for microgrids to account for interchange of power between MG; this was done by applying the alternating direction method of multipliers to the standard VIS problem, splitting it into sub-problems each MG can solve independently. Next, variations in data privacy between microgrids will be examined by changing the type of data shared for constraint generation; frequency security constraints are affected by expected disturbance levels which are calculated based on contributions from each MG. By limiting the degree to which each MG shares information, the effect of different privacy regimes on scheduling results and dynamics can be examined. Real time dynamic simulations can be carried out using the ANDES platform to determine the validity of VIS solutions and examine changes in dynamic performance.

Work on this project from the optimization side is complete while dynamics validation requires more work. An ADMM formulation for VIS which uses novel nadir constraint linearization has been developed and can solve for shared dispatch, tie-line flows, virtual inertia and damping, and contingency reserves in a 5-microgrid version of the 123-bus test system. A sensitivity study comparing scheduling results between different ADMM formulations with varying privacy shows that levels of data sharing can meaningfully affect results. For dynamic validation of frequency constraints, the RoCoF constraint is held, showing successful distributed scheduling of inertia. Unfortunately, we are having difficulty getting the nadir constraint to hold and are investigating issues with our test case and/or ANDES workflow to find the issue.

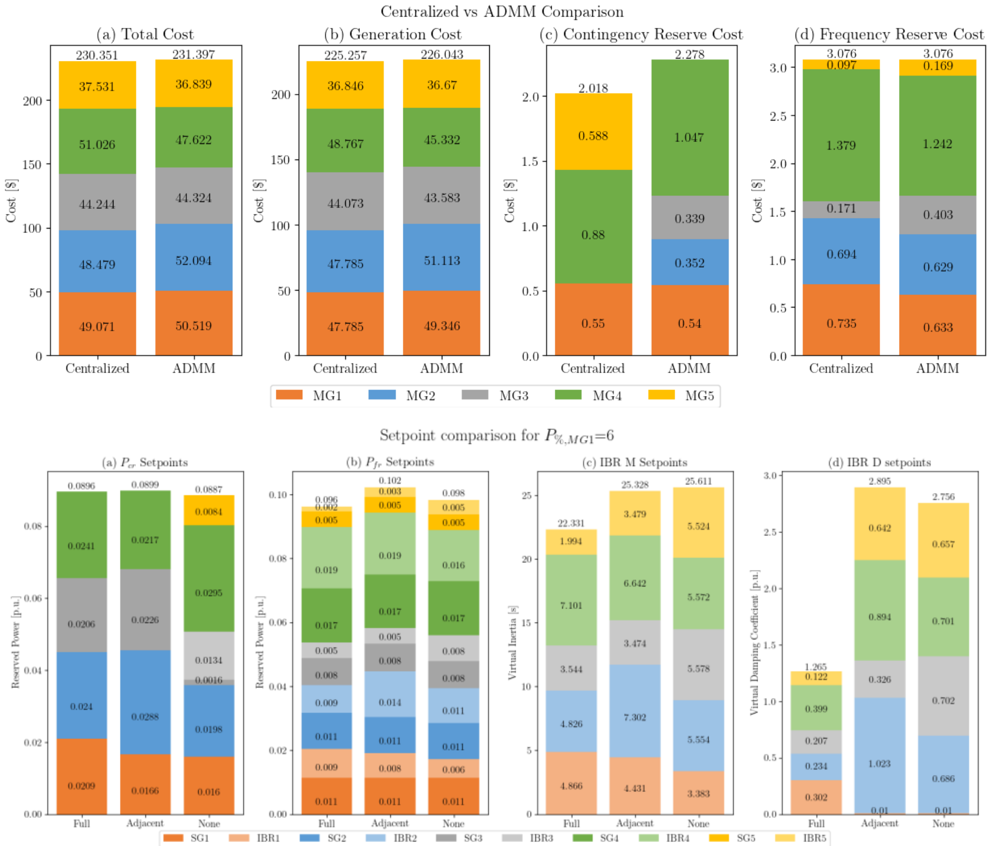

Figure 2: Scheduling results comparison for centralized vs ADMM solution and privacy sensitivity study

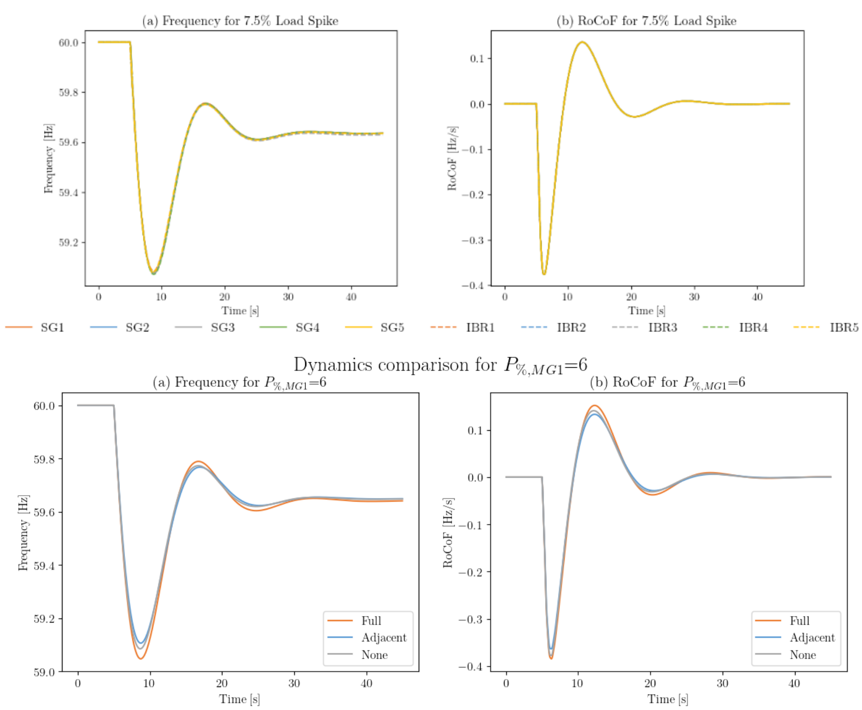

Figure 3: Dynamic results of base level ADMM-VIS dispatch and for privacy sensitivity study