Optimal Restoration Strategy to Enhance the Resilience of Transmission System under Windstorms

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***Abstract*—Windstorm causes a tremendous amount of blackouts each year in the U.S., leading to significant social and economic losses. Therefore, power system operators and local utilities are paying much attention to enhancing power system resilience under windstorms, including improving the system robustness and improving the recovery ability to return the power system into normal status. This paper focuses on the latter and proposes an optimal restoration strategy for the transmission system. The proposed model develops an approach to estimate the transmission line fault locations, transmission repairing schedule, and an economic dispatch solution on the basis of uncertainties from the windstorms. The objectives are to promote the rapidity of restoration and reduce outage costs. The proposed model is formulated as a scheduling problem. A 6-bus transmission system is applied in the case study to demonstrate the efficiency of the proposed model.**

***Index Terms*—resilience, restoration strategy, windstorm, scheduling**

NOMENCLATURE

i	Index for generation units
j	Index for loads
l	Index for transmission lines
m	Index for generation unit segment
t	Index for time
v	Index for buses
$\Delta D_{j,t}$	Deviation between scheduled and real power consuming of load j at time t
$\Theta_{v,t}$	Phase of bus v at time t
$C_{i,m}$	Operation cost coefficient for generation unit i in segment m (per 100MW)
$C_{i,t}$	No load cost for generation unit i at time t
C_{loss}	outage losses coefficient (per 100MW)
$C_{sd,i,t}$	Shut down cost for generation unit i at time t
$C_{su,i,t}$	Start up cost for generation unit i at time t
$Coef_t$	Weights of outage cost in objective function at time t
$I_{i,t}$	Status indicator of generation unit i at time t
$N_{i,0}$	No load cost coefficient of generation unit i
$P_{i,t,m}$	Output power of generation unit i in segment m at time t
$P_{i,t}$	Output power of generation unit i at time t
P_i^{max}	Upper bound output power of generation unit i
P_i^{min}	Lower bound output power of generation unit i
$P_{l,t}$	Power flow of transmission line l at time t
$Pr_{j,t}$	Priority of load j at time t
SD_i	Shut down cost coefficient of generation unit i
SU_i	Start up cost coefficient of generation unit i
X_l	Reactance of transmission line l (per unit)
$Y_{i,t}$	Start up indicator of generation unit i at time t
$Z_{i,t}$	Shut down indicator of generation unit i at time t

I. INTRODUCTION

The infrastructure resilience[1] has drawn enormous attention recently for significant socioeconomic disruptions caused by extreme events. Recent blackouts and subsequent financial losses in the United States caused by Hurricane Katrina in 2005 and hurricane Harvey in 2017 are among prime examples of such disruptions. Natural disasters can cause large blackouts[2]. Research on the impacts of the natural disaster on power and energy systems is emerging to understand the blackouts, explore ways to prepare and harden the grid, and increase the resilience of the power grid under such events [3], [4].

Based on the definition of resilience [5], resilience enhancement strategies could be categorized into two groups: enhancing the adaptation ability and enhancing the recovery ability. On the other hand, following the traditional classification of power system practices, these strategies can also be categorized from the perspective of planning and operation (Fig. 1). While the operation strategies can be further divided into three terms: preventive state, emergency state, and restorative state [6], which power grids will go through. As a result, researchers have in total of four types of grid resilience enhancement strategies (i.e., resilience planning, corrective action, emergency response, and resilience restoration).

After a power outage happens due to the damage from a natural disaster, the most important task for system operators is to restore the power system as quickly as possible to restore critical loads[7] and minimize the economic loss to customers.

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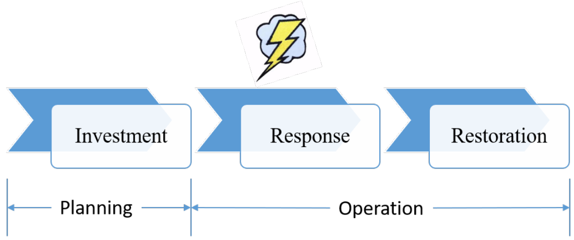

Fig. 1. The Milestones of Resilience Enhancement

Hence, service restoration has two primary objectives: restoring as much service as possible to affected customers and implementing the process as fast as possible [8].

Power systems researchers have developed multiple post-disaster restoration models in response to significant natural disasters. [9] proposed a restoration model by collecting damaged assessment information, load types and estimating the expected time to repair, employed Benders Decomposition to solve a Mix-Integer program, providing the optimal repairing schedule. [10] and [11] focused on giving the best repairing path, considering minimizing the outage lasting time. [12] presented three approximation algorithms with performance guarantees scheduling the repairs on large scale power systems.

On the other hand, in order to further increase the reaction speed, shorten outage time, researchers did a lot of work for developing outage estimation models. For windstorm, plenty of estimation models have been built. [13] developed a negative binomial regression model aiming at predicting the density of outages caused by hurricanes. Based on [13], [14] provided an improved model by only employing public data. [15] proposed a generalized additive model rather than a generalized linear model for the purpose of avoiding over-estimating. Their works indicated that hurricane or windstorm caused outage related to several types of factors: power system properties, land cover, windstorm characteristics, vegetation environment, soil and so on.

The proposed work aims at the rapidity of the restoration while considering isolated grid partitioning and random behavior of wind storms. In view of the above discussion, the main objectives and contributions of this paper are threefold:

1) Uncertainties from windstorms are considered in the outage estimation to forecasting line status.

2) Repairing strategy is proposed as an optimization scheduling problem in order to minimize outage cost.

3) Black start unit commitment is utilized in response to time varying status of transmission line under windstorms whiling considering several criteria such as self-healing time, network observability, and load pickup capability.

This paper is organized as follows: Section II depicts the restoration model. Section III present simulation results and discussion. Section IV gives the final conclusions and describes future works we should do to improve our model.

II. Model Description

A. Problem Description

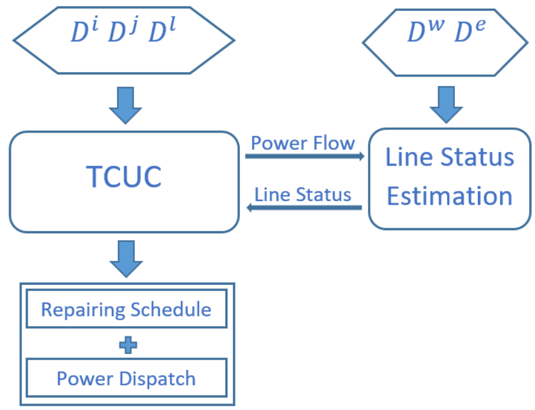

Fig. 2. Restoration Model

The Fig. 2 illustrates the flowchart of this optimization problem. The model is based on the conventional transmission-constrained unit commitment (TCUC) model and the system topology is changing all the time due to line fault occurs. From Fig.2, D^i, D^j, and D^l represent generation unit data, transmission line data, and load data respectively and they are all the inputs of TCUC model. In addition, D^w and D^e represent windstorm data and environmental data and they are the inputs of the Line Status Estimation model. These two models bonded together by power flow and line status. In this regards. the restoration strategy can be developed as the the repairing schedule and the corresponding power dispatch for the generations.

B. Outage Estimation

In this paper, we only focus on transmission line outage. Although generation units, transmission tower, substations failures may occur, line failures are more common under windstorm due to its long distance and supporting structure. [16] depicted a component fragility model in 2014. Based on it, Huang et al. (2018) displayed a model describing line failure rate p_f under windstorm [17], as equation (1) shows. In this model, p_w reflects wind-related failure rate and p_r indicates line load related failure rate, they can be accessed by equations (2)-(5) [18] [19]:

$$p_f = 1 - (1 - p_w) * (1 - p_r) \tag{1}$$

$$p_w = \begin{cases} 0 & if\ w < w_{critical} \\ p_{hw} & if\ w_{critical} \leq w \leq \omega_{collapse} \\ 1 & if\ w \geq w_{collapse} \end{cases} \tag{2}$$

where p_{hw} represents high wind line failure rate.

$$p_{hw} = \frac{w - w_{critical}}{w_{collapse} - w_{critical}} \tag{3}$$

$$p_r = \begin{cases} 1 & if\ r >= r_{limit} \\ \frac{r-r_{heavy}}{r_{limit}-r_{heavy}} & if\ r_{heavy} < r < r_{limit} \\ 0 & if\ r < r_{heavy} \end{cases} \tag{4}$$

Load rate r can be described as the ratio of practical transmission line power flow and the rated line capacity, which is:

$$r_{l,t} = \frac{P_{l,t-1}}{Capacity_l} \tag{5}$$

As discussed in Segment I, environmental conditions, such as vegetation types, soil, as well as line properties may also influence line failure rate. Those factors of one certain area can be treated as fixed considering restoration time horizon. We introduce coefficient β here reflecting their effect. Hence, line failure rate p_f can be rewritten as:

$$p_f = \alpha_1 * [1 - (1 - p_w) * (1 - p_r)] + \alpha_2 * \beta \tag{6}$$

where α_1 and α_2 are coefficients. Additionally, considering the cumulative effect of windstorm, we use γ reflecting its weight, the final line failure rate p_f can be revised as:

$$p_{f_t} = \alpha_1 * [1 - (1 - p_{w_t} - \gamma * p_{w_{t-1}}) * (1 - p_{r_t})] + \alpha_2 * \beta \tag{7}$$

C. Line status

In order to track line status, we define binary variables $U_{l,t}$ to represent transmission line status. Mathematically, $U_{l,t} = 1$ means line *l* at time *t* is in normal status, its capacity is the rated capacity; while $U_{l,t} = 0$ means it is on outage, its capacity becomes 0.

Furthermore, inspired by previous research [13], we apply a gird in the transmission system, as Fig.3 shown. The division of gird is meticulous enough that wind speed can be treated as constant. We define binary variables $U_{l,t,g}$ here to represent transmission line part status in each grid. It is obvious that:

$$U_{l,t} = \prod U_{l,t,g} \tag{8}$$

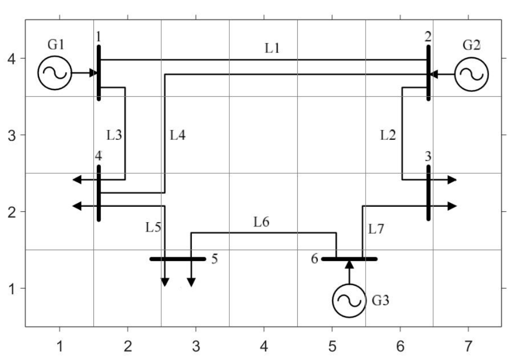

Fig. 3. Grid in 6-Bus Transmission System

For better understanding, we set two-period sections, one is the windstorm section and the other one is the restoration section. In the windstorm section, the transmission line failure rate can be determined by the following equation:

$$\begin{aligned} p_{f_{l,t,g}} = -\alpha_1 * (1 - p_{w_{l,t,g}} - \gamma * p_{w_{l,t-1,g}}) \\ *(1 - p_{r_{l,t}}) + \alpha_2 * \beta + \alpha_1 \end{aligned} \tag{9}$$

We consider $w_{critical}$, $w_{collapse}$, r_{heavy} and r_{limit} as 30m/s, 60m/s, 0.8 and 1.4 here, respectively [17]. As we obtained the line failure rate at time *t*, we want to determine the line status. By comparing $p_{f_{l,t,g}}$ and a uniformly randomly generated number $h \sim U[01]$ [18], we can express transmission line outage function $F_{l,t,g}$ as:

$$F_{l,t,g} = \begin{cases} 0 & if\ p_{f_{l,t,g}} < h \\ 1 & if\ p_{f_{l,t,g}} \geq h \end{cases} \tag{10}$$

As a result, line status can be accessed by:

$$U_{l,t,g} = U_{l,t-1,g} * (1 - F_{l,t,g}) \tag{11}$$

At the second section, as the windstorm passing away, restoration crews start to work, line status can be depicted as:

$$U_{l,t,g} = R_{l,t,g} + U_{l,t-1,g} \times (1 - R_{l,t,g}) \tag{12}$$

where *R* is the restoration indicator, indicating one restoration unit is working. Here, we assume each line part in one grid can be repaired in one unit time (1 hour) by one restoration unit.

D. Formulation

Our goal is to provide the optimal repairing schedule to minimize the total cost. Considering to correspond to the restoration process, we should also provide the economic dispatch for generations simultaneously. The objective function can be expressed as:

$$Min\ (C_{gen} + C_{outage}) \tag{13}$$

Among them, C_{gen} indicates operation cost of generation, which is obtained by [20]:

$$C_{gen} = \sum_{i,t} (C_{i,t} + C_{su,i,t} + C_{sd,i,t}) \tag{14}$$

$$C_{i,t} = \sum_{m} (C_{i,m} \times P_{i,t,m}) + N_{i,0} \times I_{i,t} \tag{15}$$

$$C_{sd,i,t} = SD_i \times Z_{i,t} \tag{16}$$

$$C_{su,i,t} = SU_i \times Y_{i,t} \tag{17}$$

While C_{outage} refers to the outage cost, which is determined by missed load $\Delta D_{j,t}$[21], [22]. It is the decisive part among the total cost:

$$C_{outage} = \sum_{j,t} \Delta D_{j,t} \times C_{loss} \times Pr_{j,t} \times Coef_t \tag{18}$$

$$\Delta D_{j,t} = D_{j,t,schedule} - D_{j,t,real} \tag{19}$$

In order to receive a practical solution, the following constraints should be taken into consideration:

1) Capacity

This is the constrain for generations. It keeps economic dispatch within a feasible range, which was determined by the generation unit property.

$$P_i^{min} \times I_{i,t} \leq P_{i,t} \leq P_i^{max} \times I_{i,t} \tag{20}$$

2) System constraint

One of the most important goals of system operators is to keep demand and supply balance all the time, even though there is an extreme event.

$$\sum_i P_{i,t} = \sum_j D_{j,t,real} \quad \forall t \tag{21}$$

3) Flow limit

In order to keep system security, we should consider the power flow limit here. The power flow in this model is derived by the N-R method, ignoring reactive power and line conductance, and assuming all the voltages are 1.0 per unit.

$$|P_{l,t}| \leq Capacity_l \tag{22}$$

$$P_{l,t} = \begin{cases} \frac{\theta_{l_{from},t} - \theta_{l_{to},t}}{X_l} & if\ U_{l,t} = 1 \\ 0 & if\ U_{l,t} = 0 \end{cases} \tag{23}$$

$$B \times \theta_{v,t} = -(P_{v,t} - D_{v,t}) \tag{24}$$

4) Restoration limit

In practice, the amount of available restoration units is also limited due to economic reasons:

$$\sum_{l,g} R_{l,t,g} \leq Restorationlimit_t \tag{25}$$

III. Case Studies

A. Simulation Result

A 6-bus system is utilized to test the proposed restoration model. This system contains 3 generation unit, 3 loads and 7 transmission lines. The related data can be obtained in [23].

We assumed that all transmission lines were in normal status originally. The transmission line grid distribution is shown in table I. We suppose the wind storm lasts for two hours, starting from the grid (7,3), moving forward to the grid (5,4), with central wind speed 48m/s, and wind speed in adjacent grids decreased by 10m/s. Wind speed in rest grids is considered less than 30m/s. We assume the priority of each load are the same, which means $Pr_{j,t} = 1, \forall j, \forall t$. We focus on 8 hours time horizon after the windstorm. In addition, we suppose that the cost of outages is \$1.16 per kWh[24].

In order to illustrate the effectiveness of the proposed model, we analyze three cases:

Case A: No restoration units are available. By analyzing this case, we can figure out the location of damaged transmission lines and estimate the outage cost without a restoration.

TABLE I
Transmission Line Grid Distribution in 6-Bus System

Line	Grid
1	(2,4) (3,4) (4,4) (5,4) (6,4)
2	(6,2) (6,3) (6,4)
3	(2,2) (2,3) (2,4)
4	(2,2) (3,2) (3,3) (3,4) (4,4) (5,4) (6,4)
5	(3,1) (3,2) (2,2)
6	(3,1) (3,2) (4,2) (5,2) (5,1)
7	(5,1) (5,2) (6,2)

Case B: One Restoration unit is available, and the restoration schedule was made based on the model presented in this paper.

Case C: One Restoration unit is available. However, power dispatch remains the same as the original schedule before the windstorm, it doesn't change with the transmission line status.

Case A

In this case, we aim to estimate the outage cost without a restoration. The result indicates the exact line fault location after a windstorm, as shown in Table II. The total cost sums up to \$ 402146. Among them, the outage cost is \$ 378160, playing a dominant role. This case illustrates the importance of rapid response, hours of delay may lead to critical financial losses.

TABLE II
Estimated Transmission Line Fault Location

Line	Fault Location	Status
1	(5,4)	outage
2	(6,3)	outage
3	-	normal
4	(5,4)	outage
5	-	normal
6	-	normal
7	-	normal

Case B

In case B, one restoration unit is available. A possible restoration schedule derived by the proposed model is Line 2 first, Line 1 second and Line 4 last (The optimal solution shows that after repairing Line 2 and Line 1, the transmission system can already supply scheduled power demand to each load. Until Hour 8, since scheduled power demand grows significantly, Line 4 is been repaired). This method moves forward reducing total cost to \$ 45896.3, with \$ 18560 outage cost. Fig 4 and Fig 5 depict the comparison of cost in those two cases.

Case C

This case is designed to demonstrate the necessity to consider generation unit commitment. In this case, we suppose generation units did not response to the unexpected outage, i.e. the generation units will be operated as scheduled. The result shows that at hour 2 and hour 3, more load is missed in this case, outage cost hence jumps to a much higher level

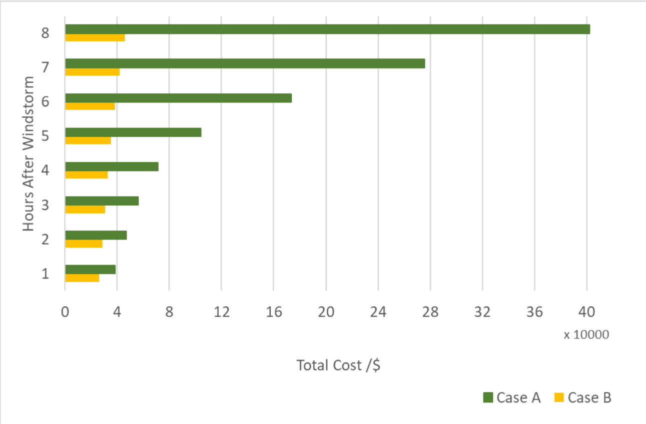

Fig. 4. Total cost by Time in Case A & B

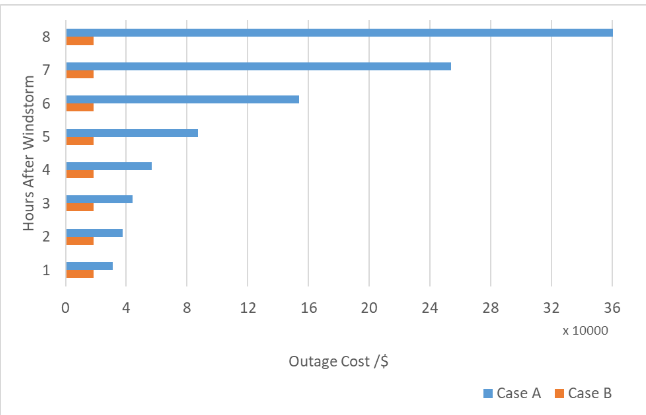

Fig. 5. Outage Cost by Time in Case A & B

(Fig 6). This is because generation units didn't response to an alternative power flow path. Repaired transmission lines were not been fully utilized, which lead to much more outage losses. In fact, it can be partly avoided by making economic dispatch solutions following the immediate line status.

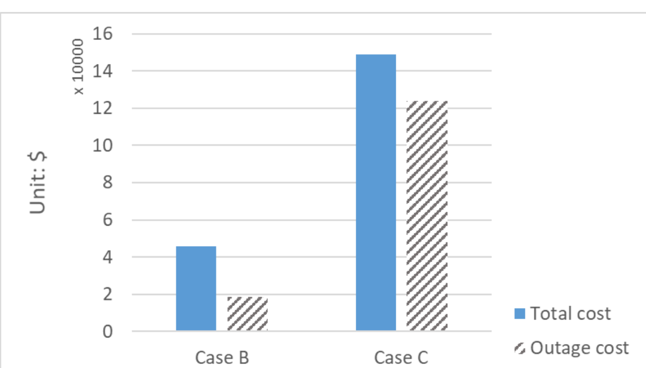

Fig. 6. Costs (8 Hours After Windstorm) in Case B & C

B. Discussion

Other factors still have an impact on potential solutions. We discuss load priority $Pr_{j,t}$ here. $Pr_{j,t}$ reflects the priority of certain load. Critical loads have higher priority. In practical, hospitals, fire stations and police offices may have higher priority. To analyze the influence of priority, we assign the priority of Load 1, Load 2 and Load 3 to 3 successively. The result appears to be an interesting one: even though the total cost remains the same, the power flow obtained in those three scenarios are different. This may because that the model tried to transfer missed load to another lower-priority load. While the total missed load remained the same. This is a special situation because the only missed load occurred at hour 2, however, in post-windstorm section (hour 3- hour 10), there is no missed load anymore. For a more complex situation, the result may be different, however, the missed loads are always prone to appear in low-priority loads.

IV. Conclusion

As extreme events occur more frequently, system resilience has attracted much attention than ever before. This paper proposed an optimization model to estimate transmission line status and apply a restoration strategy in order to deal with windstorm with stochastic characteristics to achieve the optimal outage costs. The simulation result shows the effectiveness of the proposed model. It can be developed further as a candidate tool for utility companies in restoration strategies. It can benefits both customers with shortening outage duration and generations units for better preparation. In the future, we plan to make efforts to two directions: analyzing historical data and keep training our model to get better performance; improving computing efficiency to apply this model to larger scale systems.

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