Evaluation of Metrics of Susceptibility to Cascading Blackouts

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Abstract— **In this paper, we evaluate the usefulness of metrics that assess susceptibility to cascading blackouts. The metrics are computed using a matrix of Line Outage Distribution Factors (LODF, or DFAX matrix). The metrics are compared for several base cases with different load levels of the Western Interconnection (WI). A case corresponding to the September 8, 2011 pre-blackout state is used to compute these metrics and relate them to the origin of the cascading blackout. The correlation between the proposed metrics is determined to check redundancy. The analysis is also used to find vulnerable and critical hot spots in the power system.**

Keywords—blackouts; network theory (graphs); power system operation; power system planning; power system security

I. INTRODUCTION

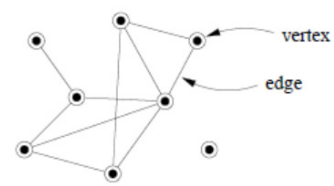
The occurrence of blackouts has drawn increasing attention to the study of cascading events. A power system has three main elements: (1) hardware to generate and carry current, (2) control and protective devices, and (3) practices and procedures of the system [2]. A cascading blackout is an uncontrolled chain of outages of current-carrying hardware that is usually initiated by failures of an element of the second or third type of the power system, when the system is under stress [2].

The blackout of Northeast North America on November 9, 1965 was triggered by a protective device, more specifically a relay, when transmission between the Niagara Falls and Toronto areas was heavily loaded [1][2][4]. The Italian blackout in 2003 started when an overloaded line sagged into a tree, but could have easily been avoided if the operators had responded correctly [3][4].The North America blackout of August 14, 2003 started with a line sagging, but some major procedural problems were held responsible for it [2][4]. Significant reactive power imbalance and problems with the Midwest ISO (MISO) state estimator (SE) and real time contingency analysis (RTCA) software were reported after investigation [5][6]. The September 8, 2011 San Diego blackout was due to a mistake by a technician, which cut a 500 kV line between APS's Hassayampa and North Gila substations in Arizona [7].

All of these blackouts could have been avoided if stress had been identified and reduced in the vulnerable and critical parts of the system.

Previous research developed tools to measure the stress or susceptibility of the bulk electric power systems to cascading blackouts [2]. The approach analyzes properties of a new network based on line outage distribution factors (LODF or DFAX matrix) instead of the familiar network based on the Y-bus matrix. The Y-bus network is excellent for studying how power flows through a network, but for the risk of cascading, the issue is how failures can propagate in the network, and the Y-bus is not very helpful. On the other hand, the DFAX matrix contains the partial derivatives of flows in vertices with respect to outages in other vertices. The vertices in the network defined by the DFAX matrix may include lines, transformers and paths or interfaces. As shown in Fig. 1, the edges represent how the effect of a failure in one vertex propagates to the other vertices — they are the line outage distribution factors.

Fig. 1. Network nomenclature [8].



The DFAX matrix has size $m_1 \times m_2$, where m_1 is the number of monitored vertices and m_2 is the number of lines subject to contingencies or outages. In contrast, the Y-bus matrix is an n x n matrix, where n is the number of buses and is less than m_1 and m_2.

The value of each DFAX is between − 1.0 and + 1.0. A $DFAX_{ij}$ of 0.5 means that 50% of the pre-outage flow on vertex j (f_{j0}) is added to the pre-outage flow in vertex i (f_{j0}), should vertex j go out of service. Similarly, a $DFAX_{ij}$ equal to zero means that the outage of vertex j will not cause any effect on the flow of vertex i. Post-outage flows for the outage of vertex j are calculated using the following equation:

$$f_i = f_{i0} + DFAX_{ij} \times f_{j0} \qquad (1)$$

The computation of the metrics requires this DFAX matrix. Definitions of these metrics are discussed in the next section. Seven base cases of the WI are then used for analysis, including five seasonal base cases of 2016, a peak summer case of 2012 and a pre-blackout case for 2011.

II. DEFINITIONS OF METRICS

A. *Vulnerability*

Vulnerability measures the post-outage flow in a vertex after the outage of other vertices in the system. This is a reasonable measure of stress because cascading always begins with an outage causing one or more other vertices to become highly loaded or overloaded. Two metrics were proposed in [2] to calculate vulnerability: the rank and the degree of vulnerability.

1) Rank of Vulnerability (RANKV):

The rank of vulnerability is the maximum absolute value of flow through a vertex in per unit of its rating for the outages of other vertices, taken one at a time. The rank matrix is a $1 \times m_1$ matrix, where m_1 is the number of monitored vertices. $RANKV_i$ is the maximum post-outage flow on vertex i for the outage of all m_2 vertices (taken one at a time), where m_2 is the number of outage vertices. Note that, $RANKV_i$ may be greater than or less than or equal to the pre-contingency flow on the vertex.

2) Degree of Vulnerability (DEGREEV):

The degree of vulnerability is the number of single outages for which a monitored vertex will be loaded over some threshold value. Thresholds of 75% and 100% of the associated line ratings were used to compute DEGREEV in this study. DEGREEV is a $1 \times m_1$ matrix, where m_1 is the number of monitored vertices. Thus, $DEGREEV_i$ is the number of vertices among all the m_2 (outage) vertices, such that the absolute value of power flow will be greater than the threshold for the i^{th} vertex, after their outage.

B. *Criticality*

Criticality measures how the outage of a vertex affects other vertices of the system. Rank and degree of criticality are used to define criticality.

1) Rank of Criticality (RANKC)

The rank of criticality of vertex i is the maximum absolute value of flow through all other vertices (taken one at a time) in per unit of their ratings after the outage of vertex i. The rank matrix is a $1 \times m_2$ matrix, where m_2 is the number of outage vertices. $RANKC_i$ is the maximum absolute value of all the post-outage flows divided by the ratings of the m_1 monitored vertices, given an outage of vertex i.

2) Degree of Criticality (DEGREEC)

The degree of criticality of an outage vertex is the number of monitored vertices that will be loaded above some threshold for the outage of that outage vertex. Thresholds of 75% and 100% of ratings were used for calculating the degree of criticality, as was done for DEGREEV. DEGREEC is also a $1 \times m_2$ matrix, where m_2 is the number of outage vertices. $DEGREEC_i$ is the number of vertices among all the m_1 monitored vertices whose flows will exceed a threshold after an outage of the i^{th} vertex.

III. COMPARISON OF THE STRESS METRICS

Five seasonal power flow base cases of 2016 include a peak and an off-peak summer case, a peak and an off-peak winter case, and a peak spring case of 2016. As a blackout occurred in the Southwestern (SW) part of the WI in 2011, our analyses focuses on this region, though all of the WI is modeled, and analyses of all of the WI have been done. The SW WI includes San Diego, Arizona, Nevada, LAWDP, Southern California Edison, and Imperial Irrigation District. Table I displays the numbers of both the radial and nonradial vertices along with the load and generation of these cases.

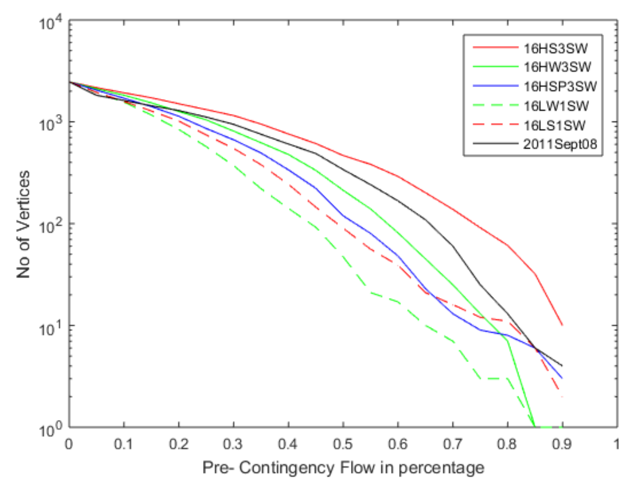
The network was reinforced between 2011 and 2016. Some 323 nonradial vertices were added, among which 126 vertices are rated from 240MW to 599MW, 109 vertices have ratings lower than 240MW and the remaining 88 vertices have ratings over 600MW.

TABLE I. WESTERN INTERCONNECTION BASE CASES STUDIED

Case ID	**Load of SW (MW) L-Load G-Generation**	**Number of nonradial and radial vertices**	**Monitored nonradial vertices**	**Outaged nonradial vertices, excluding paths**
16HS3SW (2016 high summer, SW WI)	62691.8(L) 57578.1(G)	4849	2419	2395
16HSP3SW(2016 high spring, SW WI)	44229.2(L) 40472(G)	4553	2456	2433
16HW3SW (2016 high winter, SW WI)	38931.7(L) 36085(G)	4534	2474	2450
16LW1SW (2016 low winter, SW WI)	27530.8(L) 30500(G)	4563	2462	2438
16LS1SW (2016 low summer, SW WI)	34577.5(L) 32010.4(G)	4785	2401	2379
2011Sept08SW (2011 pre-blackout, SW WI)	51619.8(L) 46752.6(G)	3564	2088	2068
12HS4aSW(2012 high summer, SW WI)	61933.4(L) 57841.6(G)	3674	2215	2198

Fig. 2 shows the pre-contingency flows of these six cases, considering nonradial lines only. Although, the September 2011 case has fewer vertices than the 2016 cases, only the high summer case of 2016 has a higher pre-contingency percentage flow compared to the 2011 pre-blackout stage.

Fig. 2. Pre-Contingency flow of the five seasonal cases and the September 2011 case (in % rating).



The DFAX distribution curve remains almost the same for all the seasonal cases, as shown in Fig. 3, since the networks are almost the same and the DFAXes do not reflect load levels. Fig. 4 shows that the number of high DFAX elements is much lower for the September 2011 case. This is because the total number of vertices in the SW WI is lower in the September case compared to the 2016 seasonal cases. The DFAX distribution curve of the high summer case of 2012 lies between these two.

Fig. 3. DFAX distribution curves for five seasonal cases of 2016.

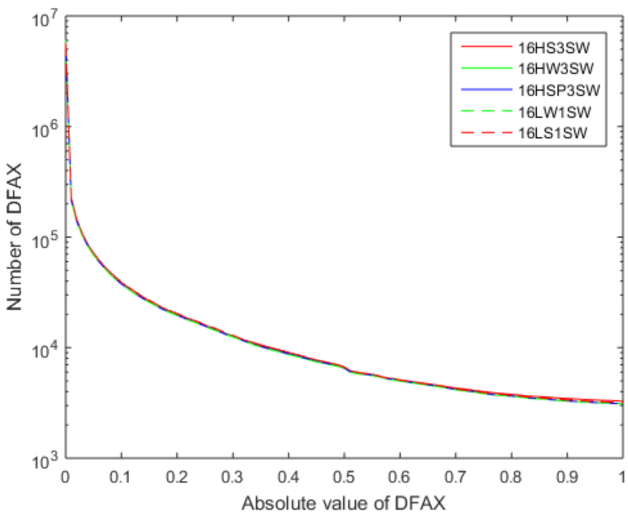


Fig. 4. Comparison of DFAX distribution curves of the two peak summer cases of 2016 and 2012 and the September 2011 case.

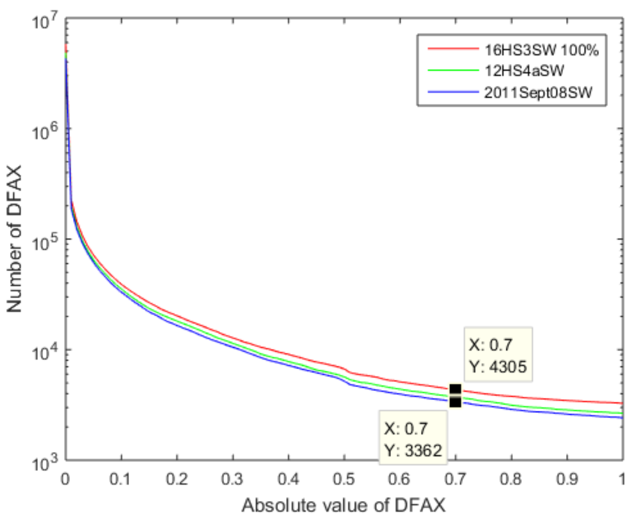


Fig. 5 shows the RANKV curves for the 2011 and 2016 cases. The 2011 curve is between the peak summer case and peak spring curves for almost all of the RANKV elements between 0.75 and 1.1. Few vertices have RANKV greater than about 1.5. They likely represent modeling errors or situations where a high-voltage vertex is parallel to a low-voltage vertex, possibly with a transfer-trip arrangement.

This issue was analyzed in part by monitoring only vertices with ratings greater than 200MW for RANKV (Fig. 6). Sweeping these under the carpet is not the solution; the high-RANKV vertices need to be looked at by planners or operators. It is sometimes tacitly assumed that problems on the lower voltage system are unlikely to affect the bulk system. But the cascading in the 2011 blackout began in the lower voltage system, after an EHV outage.

RANKV for the other three cases — high winter and low summer and winter — are close to each other and show significantly lower stress than the high spring case for this group. The RANKC curves in Fig. 7 lead to the same conclusion with broader range. The high initial plateaus in this figure are due to high pre-contingency flows. Even if many contingencies don't affect a highly-loaded vertex, the vertex will show as highly loaded for all of these contingencies.

Fig. 5. RANKV curves for the September 2011 case and the five seasonal cases of 2016.

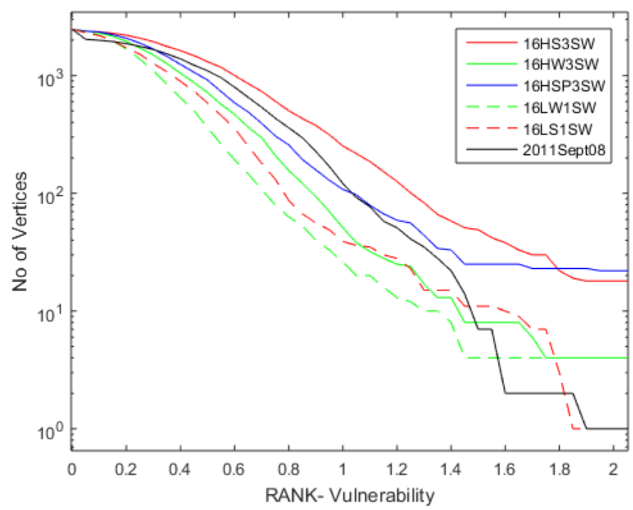
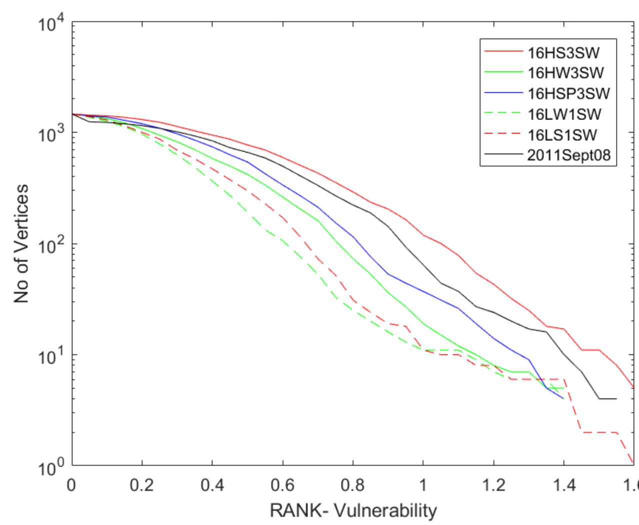


Fig. 6. RANKV curves for the September 2011 case and the five seasonal cases of 2016 considering vertices with ratings greater than or equal to 200MW.



The DEGREEV and DEGREEC curves, shown in Fig. 8 and Fig. 9, respectively, are calculated for a threshold of 100%. The results for a threshold of 75% (not shown) are not enlightening because, similar to Fig. 7, many of the vertices have pre-contingency flows over 75% and hence will be loaded over 75% for the many contingencies that do not affect them.

In Fig. 8 and in the major part of Fig. 9, the 2011 case curves lie between the peak summer case and the peak spring case of 2016. That is, the 2011 case is found more stressed than the off-peak cases of 2016 and the peak spring case of 2016 (for most of the graph). All of the figures in this section are distribution functions of the stress metrics.

Fig. 7. RANKC curves for the September 2011 case and the five seasonal cases of 2016.

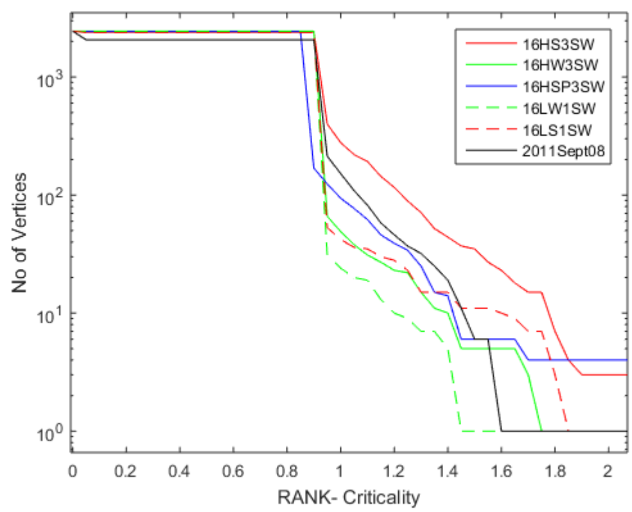


Fig. 8. DEGREEV curves for the September 2011 case and the five seasonal cases of 2016.

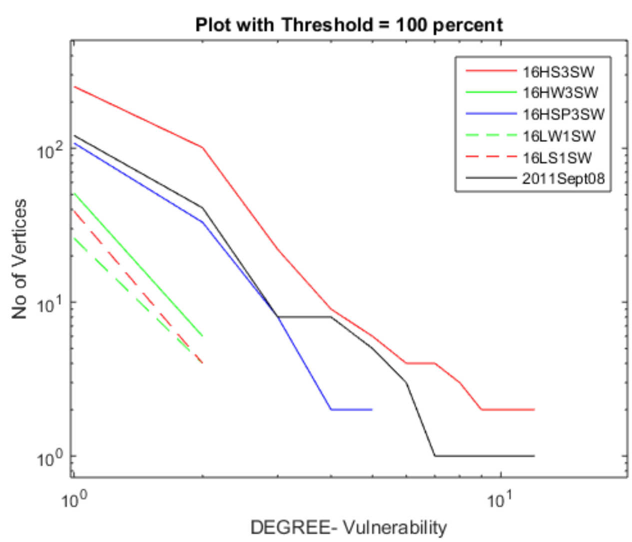
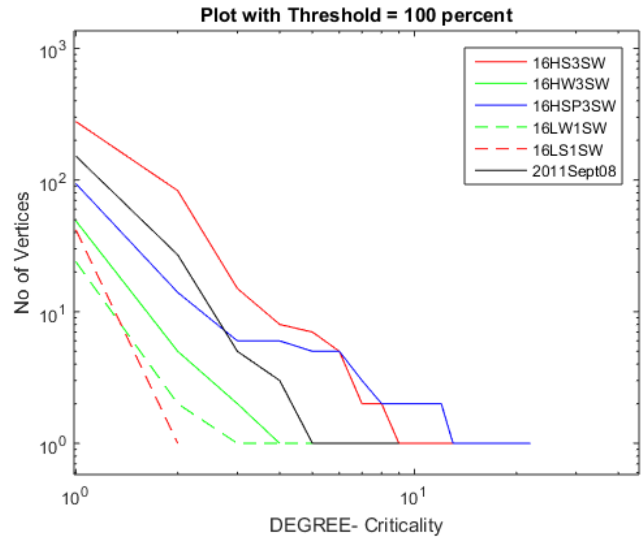


Fig. 9. DEGREEC curves for the September 2011 case and the five seasonal cases of 2016.

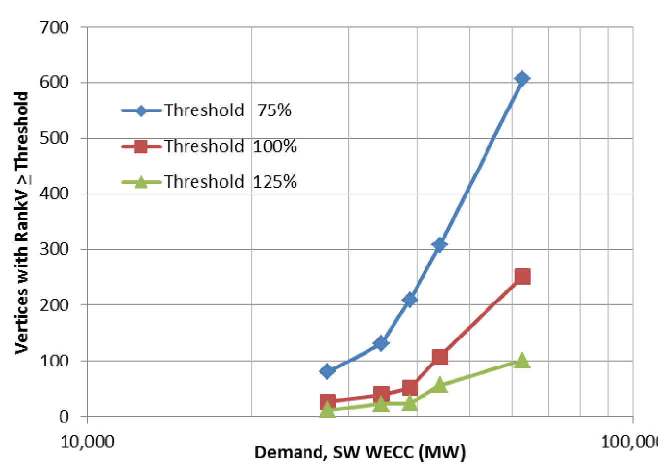


IV. Tipping Point Between Stressed and Non-Stressed States

The five operating cases for 2016 have different load levels and presumably reasonable and consistent generation dispatches. The numbers of vertices with RANKV greater than threshold for five different base cases with five different load levels are plotted in Fig. 10. That is, each marker in Fig. 10 is for a different base case on essentially the same system.

Vulnerability increases linearly with the log of demand, but the slope increases dramatically at about 35,000 MW. The reason behind this increase is more power moving across the system, obviously increasing stress. This happens no matter how we measure vulnerability — whether we consider n-1 loading $\geq$ 125% of ratings, or 100%, or 75%. (The slopes are different for n-1 loading $\geq$ 125%, 100%, and 75% of ratings.)

Fig. 10. Vulnerability rank as a function of demand, SW WI.



V. CORRELATION ANALYSIS

The correlation between the metrics was evaluated for high and low summer cases of 2016 to determine whether they are redundant. The analysis shows that these metrics are mostly independent of each other. Fig. 11 and Fig. 12 summarize the results for the two cases.

Fig. 11. Correlations between the stress metrics for the peak summer case of 2016.

	RankV	RankC	DegreeV75%	DegreeC75%	DegreeV100%	DegreeC100%
RankV	1.00					
RankC	0.25	1.00				
DegreeV75%	0.29	0.37	1.00			
DegreeC75%	0.17	0.22	-0.07	1.00		
DegreeV100%	0.44	0.27	0.57	0.06	1.00	
DegreeC100%	0.26	0.70	0.40	0.42	0.38	1.00

Fig. 12. Correlations between the stress metrics for the off peak summer case of 2016.

	RankV	RankC	DegreeV75%	DegreeC75%	DegreeV100%	DegreeC100%
RankV	1.00					
RankC	-0.02	1.00				
DegreeV75%	0.63	-0.12	1.00			
DegreeC75%	0.27	0.00	0.34	1.00		
DegreeV100%	0.93	0.00	0.68	0.49	1.00	
DegreeC100%	0.01	-0.01	0.02	-0.04	-0.01	1.00

VI. FINDING HOT SPOTS FROM THE METRICS

Table II reveals the metrics by area within the SW WI. (The Mexico CFE area was added for Table II). The 2011 blackout was initiated by the tripping of a vertex in Western Arizona that fed to Area 1. As shown in Table II, the stress metrics, computed from the pre-blackout case of 2011, identify Area 1 as the most vulnerable area, and the second most critical, in the SW WI that day.

TABLE II. COMPARISON OF VULNERABILITY AND CRITICALITY, SEPTEMBER 8, 2011

Area	Vulnerability		Criticality	
	% of Vertices with Rank≥1	*% of Vertices with Degree≥2*	*% of Vertices with Rank≥1*	*% of Vertices with Degree≥2*
Southwestern WI	5.54%	1.88%	6.97%	1.21%
Area 1	**16.13%**	**9.68%**	**11.3%**	**1.61%**
Area 2	1.61%	0.32%	3.22%	1.29%
Area 3	6.01%	1.65%	7.96%	0.75%
Area 4	0	0	0.5%	0.5%
Area 5	11.7%	4.29%	13.26%	3.31%
Area 6	2.15%	1.08%	2.15%	0
Area 7	1.68%	0.28%	4.47%	0.28%

VII. CONCLUSIONS

In this paper, stress metrics were computed for several base cases of WI. The pre-blackout stage of 2011 was found to be highly stressed and was second only to the 2016 peak summer case. The metrics identified an area in the September 8, 2011 pre-blackout state as being highly stressed: this most vulnerable and second most critical hot spot in SW WI is the area where the cascading started. Therefore, the metrics provide a powerful tool to anticipate and prevent cascading blackouts. Fortunately, significant changes have been made since 2011 to the networks and to operating procedures, so Table II is not an indicator of current exposure to cascading.

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