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A New Model For Outaging Transmission Lines In Large Electric Networks

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Abstract - **This paper presents a new method for calculating line currents for multiple line outages in large electric networks at extremely high computational speeds. An example is given showing that only one minute of computation time is needed to test 160k N-3 line outage configurations for a large network. Resulting line overloads are shown to agree well with AC load flow. The new method: 1) calculates line currents and powers for any set of multiple line outages; 2) tests for system separation due to lines outaged; 3) tests for electrical remoteness of lines being outaged, and 4) updates real power line distribution factors used in linear programming and probabilistic models. The method is restricted to passive networks in which tapped transformers are near unity.**

I. INTRODUCTION

The reliability of an interconnected electric network is highly dependent on generation availability, transmission deliverability, and network loads. The authors presented a composite generation-transmission model in [1] showing a direct method for calculating probabilistic line flow distributions for random generator outages in a large system. The line outage model presented here can be used as either a stand-alone method for deterministic line outage analysis or as a part of the generation outage probabilistic model in [1].

This line outage model is computationally very fast. Tests on a 4233 bus 5161 line network show that 99 lines can be tested for 160k different combinations of outages through N-3 triple contingencies in about one minute of computation time on a 133 MHz Pentium computer. A brute force approach of N-3 analysis is not feasible [2]. The total computational requirement is greatly reduced by discarding configurations 1) that cause islanding or system separation, 2) have too low a probability of occurrence, and 3) are too electrically isolated. The matrix equation (6) provides a convenient way to identify electrically isolated configurations and islanding. Note that the treatment of islands is beyond the scope of this paper since generation and load within each separated area is usually not conserved. Applying the isolated lines and separation tests to the example network reduces the number of statistically significant configurations from 160,000 to 1602. The 1602 cases are quickly calculated using the methods in this paper.

Computational speed is very high because the sparse nodal admittance matrix (1) is never modified for single outages. Multiple line outages are created as simple summations of single line outages that were calculated earlier in the process.

The speed gained from not modifying the matrix increases the solution error for tapped transformers. Tests show this error is minor for voltage tapped transformers with taps in the .95 to 1.05 range and for phase shifting transformers with tap angles of a few degrees. The error becomes progressively larger as taps differ from unity and zero degrees. Full AC load flow solutions can be run to verify the accuracy of the fast solution results. Matrix compensation [3] can be used to modify the admittance matrix to further reduce solution error.

The removal of a single line without matrix modification was introduced by Shoults in his 'zip flow' method [4] which is presented in section III. This paper extends his theory to include multiple lines outaged (sections IV and V) by making linear combinations of the incremental line currents calculated in the single line outages. Section VI has a simple model showing how tapped transformers introduce error. Section VII presents a large system model showing the zip flow error compared to full AC load flow for N-3 lines outaged.

II. NOTATION

ΔI_{ij}	complex current in line i for ±1 amp injection on line j
I_{bj}	base case line j complex current to be interrupted
$[\boldsymbol{I}]_b$	vector of n base case currents to be interrupted
$[\Delta \boldsymbol{I}]$	$n \cdot n$ matrix of line ΔI's from $[\Delta \boldsymbol{V}]_{i=1,\,n}$ for n injections
$H_{i,k}$	real p.u. line distribution for line i and generator k
n	number of lines simultaneously outaged
S_j	complex scalar line j injection current in p.u. amps
$[\boldsymbol{S}]$	vector of n complex injection currents in p.u. amps
ΔV_{fj}	'from' complex bus voltage for ±1 amp injection
ΔV_{tj}	'to' complex bus voltage for ±1 amp injection
V_{fbj}	line j 'from' bus base case load flow voltage
V_{tbj}	line j 'to' bus base case load flow voltage
ΔV_{fij}	line i 'from' bus voltage for ±1 amp injection on line j
ΔV_{tij}	line i 'to' bus voltage for ±1 amp injection on line j
Y_j	complex in-line admittance of line j to be removed
$[\boldsymbol{Y}]$	complex admittance matrix of the total network
$[\boldsymbol{V}]_b$	load flow base case bus voltages of the network
$[\Delta \boldsymbol{V}]_j$	network bus voltages from ±1 amp injection on line j

III. SINGLE LINE OUTAGED

Single line removal can be performed using matrix compensation [3] or by modifying Zbus [5]. This paper presents an alternative method of line removal by creating a circulation current that completely self contains both an injection current and the original 'base case' line current.

A test injection current of $(1\angle 0)$ amp is injected in and out of line j to be removed as shown in Fig. 1. This creates a set of small $[\Delta \boldsymbol{V}]_j$ 'test' voltages throughout the network. Injecting both the in and out currents at the same time reduces the matrix computational error. Incremental voltages created on the from and to end of line j are ΔV_{fj} and ΔV_{tj} respectively.

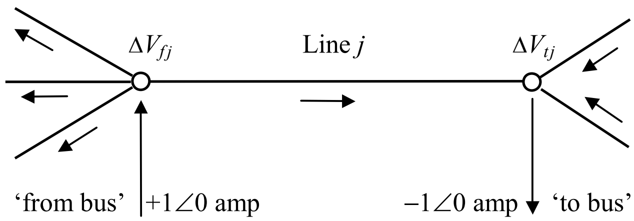

Fig. 1 Inject 1 Amp In And Out Of Line j

Fig. 2 shows the incremental line j current $(\Delta V_{fj}-\Delta V_{tj})Y_j$ being scaled by a complex number S_j in order to create a circulation current that is completely self contained as a loop current within line j. This current includes the original base case load flow current as well as the portion of the injected current flowing in line j. Line j base case current is not canceled by this process. The purpose is to self-contain the base case current within the local circulation current set up by S_j so that no line currents from other adjacent lines from either the base case or from the injected currents flow across the gaps shown in Fig. 2. In practice the line is not removed from the matrix solution, but the equivalent delta voltages in the network are the same as though line j has been removed.

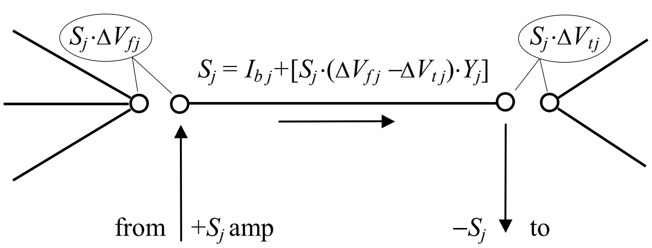

Fig. 2 Single Line Removal Using S_j Injection Current

The steps to calculate S_j are given below. The base case bus voltages are $[\boldsymbol{V}]_b=[\ldots V_{fbj}\ \ldots V_{tbj}\ \ldots]^T$ and the base case complex current in line j to be removed is I_{bj}. The calculation of I_{bj} should not include shunt elements to ground such as line charging. Shunts are also excluded from the $[\boldsymbol{Y}]$ nodal admittance matrix to insure that incremental currents are contained within the transmission lines rather than being shorted to ground through shunt elements. The absence of shunts produces results more consistent with full AC load flow solutions of line outages.

Line currents are conveniently measured on the 'to' end of every line because the standard tapped transformer model normally has the series Z directly connected to the 'to' bus. The transformer Z is used in the nodal admittance matrix $[\boldsymbol{Y}]$ as though it is a regular transmission line. Transformer tap and angle information is not included in the $[\boldsymbol{Y}]$ matrix. This simplification introduces error. However, the examples in section VI show this error is small for a tap ratio of .95 and a small phase shift angle of 3 degrees.

The $[\boldsymbol{Y}]$ complex nodal admittance matrix of the network is constructed from real and reactive in-line series impedances. One bus in the network is grounded using a low impedance shunt element and remains at zero incremental volts at all times. While any bus may be the grounded bus, it should be one that can regulate the voltage under severe line outage conditions in a full AC load flow. No other shunt elements are to be included in $[\boldsymbol{Y}]$.

The next step is to find the set of all $[\Delta \boldsymbol{V}]_j$. ΔV_{fj} and ΔV_{tj} are incremental voltages resulting from the injection of $\pm 1\angle 0$ amp into line j as shown in Fig. 1. Eqn. (1) shows this is a standard nodal admittance matrix solution. The authors use the sparse matrix technique in [6] to efficiently solve (1). Other sparse matrix solution methods are presented in [7].

$$[\Delta \boldsymbol{V}]_j = [\ldots\Delta V_{fj}\ldots\Delta V_{tj}\ldots]^T = [\boldsymbol{Y}]^{-1}[\ldots 1\ldots -1\ldots]^T \qquad (1)$$

The $[\Delta \boldsymbol{V}]_j$ calculated from the $\pm 1\angle 0$ amp injections for line j are saved for use in other calculations such as the outaging of many lines. The complex scale factor S_j for scaling the incremental network bus voltages is given in (2).

$$S_j = \frac{I_{bj}}{1-(\Delta V_{fj}-\Delta V_{tj})Y_j} \qquad (2)$$

S_j is also the complex injection current that produces the totally self contained current in line j as shown in Fig. 2. If less than .00001 per unit amps injection current flows through the rest of the network, there effectively are no alternative paths for the injected current to flow other than the outaged line j. Then, the network will be broken into two islands by the outage of line j, if (3) is true.

$$\left|1-(\Delta V_{fj}-\Delta V_{tj})Y_j\right| \leq .00001 \qquad (3)$$

Eqn. (4) creates a temporary $[\boldsymbol{V}]_{\text{new}}$ set of voltages for the outage of line j. Line currents including line shunt currents

$$[\boldsymbol{V}]_{\text{new}} = [\boldsymbol{V}]_b + S_j\cdot[\Delta \boldsymbol{V}]_j \qquad (4)$$

are calculated using $[\boldsymbol{V}]_{\text{new}}$ to check for line overloads with line j outaged. This process is repeated for all single lines outaged and all $[\Delta \boldsymbol{V}]_j$ are saved for use in other calculations.

IV. MULTIPLE LINES OUTAGED

Multiple line removal is an extension of single line removal in which complex scalar S_j becomes complex vector [$\boldsymbol{S}$] for n lines outaged simultaneously. S_j elements of [$\boldsymbol{S}$] are injection currents into and out of each of the lines j=1...n. An example for n = 3 is shown in Fig. 3. I_{b1}, I_{b2}, I_{b3} are the base case line complex currents for lines 1, 2, and 3, respectively. ΔI_{11}, ΔI_{22}, ΔI_{33} are the line self currents from the $\pm 1\angle 0$ amp injections on each individual line. ΔI_{12}, ΔI_{13}, ΔI_{21}, ΔI_{23}, ΔI_{31}, and ΔI_{32} are the line transfer coupling currents from the $\pm 1\angle 0$ amp injections. For example, ΔI_{12} is the current in line 1 from the $\pm 1\angle 0$ amp injection in line 2.

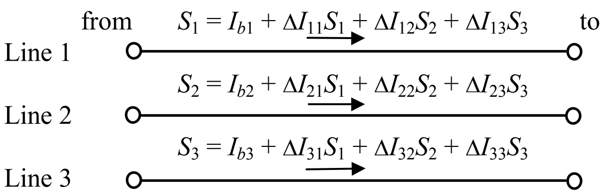

Fig. 3 Three Lines Outaged Example

Incremental ΔI_{ij} currents on lines i for injections j are calculated as shown in (5) from the set of $[\Delta V]_j$ calculated in Section III.

$$\Delta I_{ij} = (\Delta V_{fij} - \Delta V_{tij})\, Y_i \tag{5}$$

Rearranging the equations shown in Fig. 3 for n = 3 produces a matrix equation for finding complex [$\boldsymbol{S}$] vector.

$$\begin{bmatrix} 1-\Delta I_{11} & -\Delta I_{12} & -\Delta I_{13} \\ -\Delta I_{21} & 1-\Delta I_{22} & -\Delta I_{23} \\ -\Delta I_{31} & -\Delta I_{32} & 1-\Delta I_{33} \end{bmatrix} \begin{bmatrix} S_1 \\ S_2 \\ S_3 \end{bmatrix} = \begin{bmatrix} I_{b1} \\ I_{b2} \\ I_{b3} \end{bmatrix} \tag{6}$$

[$\boldsymbol{S}$] complex scale factors (bus injection currents) simultaneously disconnect all n lines from the network. Eqn. (6) is solved using Gauss elimination since the matrix is dense and small. Diagonal terms are used as pivot elements. A singularity of (6) occurs if a diagonal term becomes nearly zero. This condition indicates a system separation which means a part of the system is isolated.

Skipping the outaging of lines that are electrically remote can be determined from the column elements of (6). $|\Delta I_{21}/(1-\Delta I_{11})|$ is the amount of current in outaged line 2 due to an incremental current of 1 A in outaged line 1. If this ratio is small (≤ .01), the two lines are remote from each other electrically. Being remote means the multiple line outage case produces no new information over cases previously run.

After (6) is solved, the new bus voltages $[\boldsymbol{V}]_{\text{new}}$ for the case of multiple n lines simultaneously outaged can be calculated using (7). Line currents including line shunt

$$[\boldsymbol{V}]_{\text{new}} = [\boldsymbol{V}]_b + \sum_{j=1}^{n} S_j \cdot [\Delta \boldsymbol{V}]_j \tag{7}$$

currents are calculated using $[\boldsymbol{V}]_{\text{new}}$ to check for line overloads with lines j=1...n outaged. The processes in sections III and IV are repeated for other sets of line outages.

<u>Summary Of Steps For Outaging Multiple Lines:</u>

1. Solve an initial load flow and store the complex line currents for this 'base case' with no lines outaged.
2. Outage each of the lines individually using (1)-(4), test the rest of the network for line overloads, and store in memory or disk the incremental line currents in all lines resulting from the 1 A injections for each line outaged.
3. Set up a procedure for stepping through each outage configuration for N-2, N-3, etc.
4. Calculate a probability of occurrence for each multiple line outage configuration and skip the simulation of configurations with too low a probability.
5. Construct matrix (6) from the currents in step 2.
6. Calculate the electrical 'remoteness' of lines being outaged by testing all the column elements of (6); example: $|\Delta I_{21}/(1-\Delta I_{11})|$, etc. If any of these ratios are below a small number (.01 for example), then skip the outage, because the same lines will have been outaged individually at another point in the process of modeling all combinations of line outages.
7. Solve for new [$\boldsymbol{S}$]. Matrix (6) is inverted using Gauss elimination and diagonal term pivoting. Singularity occurs if the lines outaged have isolated one or more buses from the main network.
8. Calculate new line currents for this contingency using the new bus voltages calculated in (7).
9. Overloaded lines are found and reported.
10. Steps 3 - 9 are repeated for each multiple line outage.

V. REAL POWER MODEL

Sections III and IV presented line outage models based on linear summations of complex incremental line currents. However, complex incremental currents are not directly usable in linear programming and probabilistic models based on the use of real numbers. In [1] the real power distribution factors $H_{i,k}$ are the set of per unit incremental real powers in all lines i due to all generators k. The $H_{i,k}$ factors are calculated in [1] using incremental AC load flow solutions. This section presents a method for modifying the $H_{i,k}$ factors to represent real power distributions for each multiple line outage configuration.

Real Power Matrix Approach Fails:

A line outage model was developed using all real powers in a matrix similar to (7) for multiple lines outaged in order to calculate a set of real [S] scale factors. The real power model worked well in predicting incremental line powers for single line outages. It frequently failed to predict system separation because the real matrix was not singular enough when the system was in a state of islanding. It performed poorly for multiple line outages in predicting real power flow distributions. Subsequently, the approach using only a real power matrix to model line outages was abandoned.

Real Powers From Complex Currents Approach Succeeds:

The successful solution approach is to perform line outages using (1)-(7). These contain complex incremental currents and voltages due to line outages. Real incremental powers are calculated as a secondary calculation from the complex incremental currents in the line outage model.

Each generator k has a set of $H_{i,k}$ real power per unit distribution factors for all lines i. For any line or lines outaged, each set of power distribution factors for each generator is updated as a separate operation for each generator. These updated factors are calculated and used immediately and then disposed of because there are far too many to store in computer files or memory. The updating process presented here is very computationally efficient and is orders of magnitude faster than running successive load flows to generate new distribution factors.

Assume line j is to be outaged. Generator k has a per unit real power flow in line j of $H_{j,k}$. The objective here is to open this line and observe the $H_{j,k}$ power redistribution in the network. However (2) requires that a line current be interrupted rather than a real power flow. The per unit line j current to be interrupted is calculated from the real power

$$I_j = \left[\frac{H_{j,k}}{V_{tbi}}\right]^*, \tag{8}$$

where I_j is a complex current representing real power in line j as though it were a base case current. Eqns. (2)-(4) are now applied to open line j and interrupt this current. New incremental per unit line currents ΔI_{ij} throughout the network are calculated. The reverse process of (8) is used in (9) to turn the line i incremental currents due to line j being outaged back into incremental real power flows ΔH_i.

$$\Delta H_i = \text{Re}\{V_{tbi} \cdot \Delta I_{ij}^*\} \tag{9}$$

The $H_{i,k}$ real power distribution factors are updated using (10) and the outaged line j $H_{j,k}$ is set to 0 since it has no flow.

$$H_{i,k} = H_{i,k} + \Delta H_i \tag{10}$$

The above example is for a single line outaged. The same process is used for multiple lines outaged. Eqns. (5)-(7) are used to calculate the S_j factors.

$$\Delta H_i = \text{Re}\{V_{tbi} \cdot (\sum_{j=1}^{n} S_j \cdot \Delta I_{ij})^*\} \tag{11}$$

Then (11) is used to calculate the set of incremental powers due to the simultaneous outages of the many lines $j=1...n$ for $i \neq j$.

VI. SMALL TEST SYSTEM EXAMPLE

Fig. 4 shows a very small test system used to compare the zip flow method results with load flow. T/Ø is the transformer tap ratio and angle in degrees. R+jX is a series resistance and reactance on a 100 MVA per unit base. V_1 voltage at the generator bus G is held constant at 1 per unit and zero degrees. V_2 is a complex variable voltage at bus 2. Each 50 MVA rated line is outaged for various combinations of tap and line impedance.

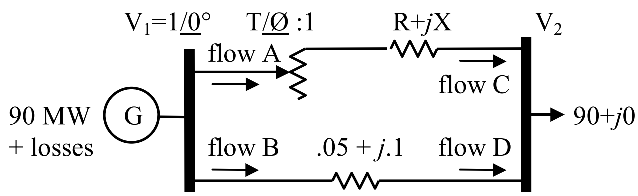

Fig. 4 A Very Small Test System

The top line in Fig. 4 is modified to represent a regular line in cases 1 and 5, a series capacitor in case 2, a phase shifting transformer in case 3, and a voltage regulating transformer in case 4. Table 1 shows zip flow versus load flow results of outaging these lines. Flows A and B are shown in actual MW and MVAR for AC load flow (ACLF) whereas flows C and D are listed in percent of line current loading on the 'to' end of each line, which is the metered end in the zip flow (ZIPF) calculations.

Case 1 in Table 1 has identical lines. Outaging either line shows the zip flow solution predicts line current will increase from 92% of line rating to 184%. The AC load flow shows actual loading to be 190%. The 6% zip flow error is due to the decrease in V_2 voltage and is roughly equal to twice the drop in voltage. Case 2 shows that the zip flow with complex numbers easily handles odd R and X combinations accurately.

Cases 3 and 4 show that tapped transformers modeled with this zip flow solution produce progressively greater error as the tap is moved away from unity. Case 4 indicates that the error introduced by the .95 tap ratio may produce either a larger or smaller error than the voltage drop in Case 1. The phase shifting transformer in Case 3 introduces error for such a small angle across the transformer.

Table 1. AC Load Flow Versus Zip Flow Results

Type	R	X	T	Ø	FlowA	FlowB	C	D	V_2
Case 1. Both lines are identical.									
ACLF	.05	.1	1	0°	46.1+*j*2.1	46.1+*j*2.1	92%	92%	.976 -2.6°
ACLF	Outage either line.				94.5+*j*9.0			190%	.948 -5.4°
ZIPF								184%	
Case 2. The top line has a series capacitor.									
ACLF	.05	-.02	1	0°	19.4+*j*34.5	74.7-*j*34.3	79%	164%	.956 -.1°
ACLF	Top line is outaged.				------	94.5-*j*1.8	-----	189%	.953 -1.1°
ZIPF							-----	188%	
ACLF	Bottom line is out.				94.5+*j*9.0	-----	190%	-----	.948 -5.4°
ZIPF							188%	-----	
Case 3. The top line is a phase shifter.									
ACLF	.0	.1	1	-3°	71.8+*j*8.6	18.3-*j*3.0	145%	37%	.994 -1.1°
ACLF	Top line is outaged.				------	94.5-*j*9.0	-----	190%	.948 -5.4°
ZIPF							-----	181%	
ACLF	Bottom line is out.				90.0+*j*8.2	-----	181%	-----	.996 -2.2°
ZIPF							181%	-----	
Case 4. The top line is a tapped transformer.									
ACLF	.0	.1	.95	0°	55.2+*j*39.6	36.0-*j*33.0	129%	98%	1.016-3.0°
ACLF	Top line is outaged.				------	94.5-*j*9.0	-----	190%	.948 -5.4°
ZIPF							-----	177%	
ACLF	Bottom line is out.				90.0+*j*7.4	-----	172%	-----	1.049-4.7°
ZIPF							177%	-----	
Case 5. Both lines are identical and the load is 90 MVAR.									
ACLF	.05	.1	1	0°	1.1+*j*47.2	1.1+*j*47.2	94%	94%	.952 -1.4°
ACLF	Outage either line.				5+*j*100			200%	.899 -2.9°
ZIPF								189%	

This example uses the complex injection currents to estimate new line currents. The phase shifting transformer is a power flow modifying device and a more accurate approach with a phase shifting transformer is to create an incremental real power flow model like the approach taken in (1) and then interrupt the real power flow in the phase shifting transformer as described in Eqns (8)-(11). The process for accurately modeling the phase shifting transformer in the context of the method in this paper is not yet developed.

Case 5 shows the zip flow works equally well for both reactive power flows and real power flows. This outcome is only true when complex number matrices are used.

VII. LARGE SYSTEM PLANNING EXAMPLE

A 4233 bus 5161 line test system is used to compare the zip flow method in this paper with full AC load flow. This is the same large scale example that was used in [1]. Testing is limited to outaging 99 lines within the City of Austin control area. For N-3 testing this is 161800 unique line outage configurations. In order to have many line overloads, the Austin load is increased from 1666 MW to 2334 MW and a 540 MW generation plant inside the local Austin area is relocated to a major transmission bus remote from Austin. The imported power from remote generation is 1498 MW. The zip flow for testing all 161800 line outage configurations through N-3 is <u>one minute</u> for a 133 MHz Pentium computer.

The authors use .01 hours per year (1.14e-6 probability) as a cutoff, i.e. any multiple outages less than this cutoff are not run. The experience of the authors is that the inclusion of contingencies with probabilities below this cutoff adds a negligible amount of new information. The examples shown in sections VI and VII use an FOR (forced outage rate) of .1% for lines, 4% for transformers. If two or more lines are connected to the same bus, an additional 1.e-4 is added to the multiple line outage probability.

To test the accuracy of the zip flow results, all of the 1602 cases were solved using a full AC load flow. Autotransformer taps were held constant in the AC load flow cases. About four hours of computer time was required. The full AC load flow had 51 occurrences of voltage collapse. In each of the voltage collapse cases the zip flow also had severe line overloads. For the remaining non-voltage collapse cases, Fig. 5 below shows how well the zip flows predict line overloads compared with full AC load flows.

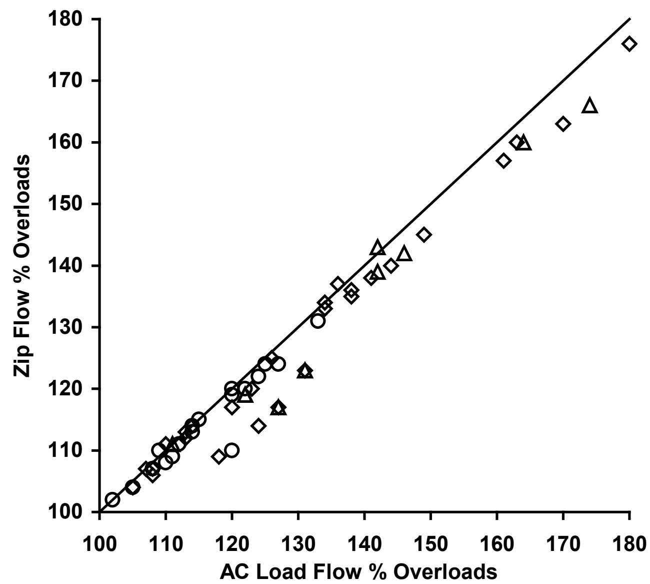

Fig. 5 Zip Flow Versus AC Load Flow

In Fig. 5, the circles represent single line outages, diamonds represent double line outages, and triangles represent triple line outages. Points that lie on the line have zero error. Many of the zip flow points are slightly below the reference line because the actual load flow voltages dropped under the contingency conditions and the actual line current became larger than predicted by the zip flow. However, the overall performance of the zip flow is good as shown in Fig. 5 and the results are quite acceptable for planning a future transmission system. The very high zip flow solution speed of over 200 times that of an AC load flow allows many more options to be examined than would otherwise be possible.

The zip flow can be run another way using only real power flows as described in [1]. How well this works is illustrated by the following test. Fig. 6. shows autotransformers $A_1...L_2$, line D, and line P will be monitored as several combinations of lines are outaged.

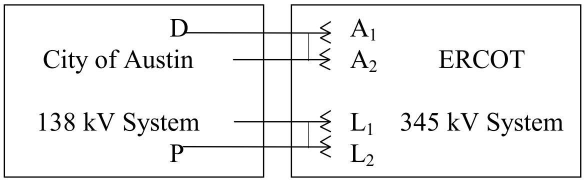

Fig. 6 City of Austin Large System Network Test Case

Tables 2 and 3 show the MW flows on the six lines. 'Out' refers to a line being outaged for the specific case. Table 3 has the same line outages as Table 2 and includes 710 MW outage of generation at bus D. Each box lists the line flow MW for the zip flow solution, the AC load flow solution, the difference in MW which is the error, and the percentage error based on 480 MVA line and autotransformer ratings. Table 2 shows the multiple line outage model produces excellent approximations of line flows for up to the N-3 contingency level for this large system.

In this example, the City of Austin load level is maximized to 2334 MW with 74 MW transmission losses.

The four autotransformers A1...L2 are loaded to a total of 1143 MW and 430 MVAR in the base case. Internal COA generation is 910 MW. None of the lines listed in Tables 2 and 3 are overloaded in the base case and all voltages are nominal (greater than .95 per unit). The base case has all generation running at maximum output with area loads scaled to equal area generation owned plus firm purchases less firm sales less area loss.

Table 3 includes an additional outage of 710 MW generation at bus D on top of the same line outages in Table 2. The linear line distribution factors produce reasonably accurate approximations of line flows in the zip flow 'base' case considering that they are nothing more than sums of real numbers from lookup tables. The process of adjusting the *H* line distribution factors works well as evidenced by the low errors in Table 3 for extremely wide variations in power flow due to the multiple line outages.

Table 2. Transmission Line Flows Due To Line Outages,
No Generation Outaged

Zip Flow - AC Load Flow = Zip Flow Error

Case	Line A1	Line A2	Line D	Line L1	Line L2	Line P
base	-277.0 -277.2 0.2 <1%	-270.6 -270.8 0.2 <1%	260.9 259.9 1.0 <1%	-297.1 -297.3 0.2 <1%	-297.1 -297.3 0.2 <1%	334.7 332.6 2.1 <1%
1	out	-423.8 -416.5 -7.3 1.5%	225.6 223.9 1.7 <1%	-329.1 -332.2 3.1 <1%	-329.1 -332.2 3.1 <1%	380.2 381.9 -1.7 <1%
2	-313.3 -315.8 2.5 <1%	-306.1 -308.5 2.4 <1%	310.0 312.7 -2.7 <1%	out	-505.3 -499.1 -6.2 1.3%	271.6 264.9 6.7 1.4%
3	out	out	103.3 107.5 -4.2 <1%	-438.5 -442.4 3.9 <1%	-438.5 -442.4 3.9 <1%	538.4 536.8 1.6 <1%
4	out	-486.3 -482.9 -3.4 <1%	275.4 278.2 -2.8 <1%	out	-567.7 -566.5 -1.2 <1%	316.1 312.8 3.3 <1%
5	-519.1 -517.2 -1.9 <1%	-507.1 -505.2 -1.9 <1%	591.3 589.1 2.2 <1%	out	out	-91.7 -92.7 1.0 <1%
6	out	out	148.1 158.3 -10.2 2.1%	out	-795.2 -794.9 -0.3 <1%	480.9 473.8 7.1 1.5%
7	out	-876.6 -864.5 -12.1 2.5%	591.3 593.7 -2.4 <1%	out	out	-91.7 -92.9 1.2 <1%

Table 3. Transmission Line Flows Due To Line Outages,
710 MW Generation Outaged

Zip Flow - AC Load Flow = Zip Flow Error

Case	Line A1	Line A2	Line D	Line L1	Line L2	Line P
base	-289.2 -294.4 5.2 1.0%	-282.5 -287.6 5.1 1.0%	365.7 377.6 -11.9 2.5%	-280.0 -279.9 -0.1 <1%	-280.0 -279.9 -0.1 <1%	341.8 339.9 1.9 <1%
1	out	-442.4 -442.5 0.1 <1%	328.8 338.7 -9.9 2.1%	-313.4 -317.2 3.8 <1%	-313.4 -317.2 3.8 <1%	398.4 392.4 6.0 1.3%
2	-323.5 -330.5 7.0 1.5%	-316.0 -322.9 6.9 1.4%	411.9 426.1 -14.2 3.0%	out	-476.1 -470.6 -5.5 1.1%	282.4 276.6 5.8 1.2%
3	out	out	201.1 214.1 -13.0 2.7%	-427.5 -435.1 7.6 1.6%	-427.5 -435.1 7.6 1.6%	554.5 557.6 -3.1 <1%
4	out	-501.9 -505.3 3.4 <1%	376.2 389.2 -13.0 2.7%	out	-540.6 -541.8 1.2 <1%	328.4 327.0 1.4 <1%
5	-517.4 -520.5 3.1 <1%	-505.3 -508.5 3.2 <1%	677.0 681.6 -4.6 <1%	out	out	-59.9 -60.3 0.4 <1%
6	out	out	244.8 262.3 -17.5 3.6%	out	-775.4 -783.2 7.8 1.6%	498.4 496.4 2.0 <1%
7	out	-873.6 -870.6 -3.0 <1%	677.0 684.3 -7.3 1.5%	out	out	-59.9 -60.4 0.5 <1%

VIII. CONCLUSIONS

The zip flow model presented in this paper allows multiple lines to be outaged in a network using summations of complex scaled voltages from 1 amp current injections. Matrix modification is not necessary for any set of lines outaged. The method is shown to produce good results compared with full AC load flow solutions provided voltages swings are not excessive and transformer taps are near unity. Execution speeds greater than 200 times AC load flow have been demonstrated. This zip flow model is applicable to large networks using AC load flow, linear programming, and probabilistic load flow methods and represents an important contribution to the industry in the analysis of power system reliability adequacy.

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X. BIOGRAPHIES

Eugene G. Preston, (M,71), was born on August 25, 1947, in Dallas, Texas. He received the BS degree in Electrical Engineering from The University of Texas at Arlington in 1970 and the MSE, specializing in Electrical Engineering, from The University of Texas at Austin in 1979. He received his Ph.D. in Electrical Engineering from The University of Texas at Austin in May 1997.

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