A New Planning Model For Assessing The Effects Of Transmission Capacity Constraints On The Reliability Of Generation Supply For Large Nonequivalenced Electric Networks

Eugene G. Preston, M
City of Austin Electric Utility Department
Austin, Texas 78704

W. Mack Grady, SM   Martin L. Baughman, SM
Department of Electrical and Computer Engineering
The University of Texas at Austin
Austin, Texas 78712

***Abstract* - This paper presents a new model for calculating the reliability of large electric networks with transmission constraints. Generation loss of load probability (LOLP) and expected unserved energy (EUE) are calculated with and without transmission constraints and displayed for the system and for each load area over a wide range of load levels. A two step process first finds the cumulative probabilistic line flow distributions from incremental flows resulting from random generator failures and then performs load shedding as a heuristic process to remove line overloads. Convolution of states allows an extremely large number of generator states to be modeled in a reasonable amount of computation time. Test results for a large network and for the IEEE Reliability Test System (RTS) are discussed in the paper.**

I. INTRODUCTION

Large electric power networks today are highly interconnected through high voltage transmission lines to reduce costs and improve reliability. The sharing of generation reserves greatly improves power supply reliability. Economy energy transfers reduce operating costs. By design, today's systems have a high degree of freedom to dispatch scheduled generation. This also allows an extremely large number of unscheduled random generator outage states. A network with 200 generators has more than 10^{60} states in which the generators can randomly fail. Most states have very small probabilities, but because of the large number of states, their collective effect on system reliability is significant. The analysis of generator outages must be extended well beyond double contingency analysis [1,2].

This paper presents a model for calculating the probabilistic transmission line power flows for the complete set of random and independent generation failure states on all the lines in a large nonreduced network. Piecewise Quadratic (PQ) math [3] is used to efficiently calculate the numerous probabilistic line flow distributions and the system generation distribution [4].

Published in IEEE PAS August 1997, pages 1367-1373.

Fig. 1 shows an example of the system generation distribution $F_G(x)$ for a 58197 MW system with 286 generators. $F_G(x)$ is the probability that generation outaged capacity will exceed x MW [5]. It also defines the generation loss of load probability (LOLP) at different MW load levels. The integral of $F_G(x)$ from x to infinity gives the generation expected unserved energy (EUE) for a one hour period. Transmission constraints will increase $F_G(x)$ in value but it is always a monotone decreasing function.

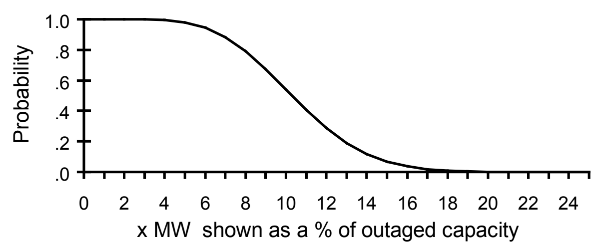

Fig. 1. Probability Outaged MW > x

The definition of $F_G(x)$ as the reliability of total system power supply is extended to mean the reliability of supply at all buses in the load flow. Every bus receives a proportionate share of the total system generation capacity. In this model loads are scaled to match each state's MW generation capacity. The *top state* load flow is one in which all generators are on line. As generators are outaged, loads are scaled downward to match available generation. Each generation state has a unique set of line flows and a probability of being in that state. The collection of all line flow states creates a set of line flow distributions. These distributions are used to estimate the changes to $F_G(x)$.

Linear incremental real power per unit line flow distributions are calculated for each line and generator outaged using a very tight tolerance load flow solution. These distributions are stored in a file. Load buses are given *virtual* generators equal to the load at each bus. Rather than decrease loads, the virtual generation is added to each bus, effectively removing load. The per unit line flow distributions are calculated and stored for all the virtual generators.

All combinations of real and virtual generation pairs are reviewed as candidates for load shedding. A load shedding table (LST) is created for each line. Load sheddings are executed as a heuristic to unload the overloaded lines and at the same time incrementally modify the $F_G(x)$ generation reliability function.

II. NOTATION

C_k , FOR_k	generator k unit MW rating, forced outage rate
D_k , $DFOR_k$	generator k MW derating, derating outage rate
h	MW grid increment spacing for PQ functions
EUE(x)	expected unserved energy in MWH for one hour
$F_E(x)$	exact generation cumulative distribution
$F_G(x)$	PQ generation cumulative distribution function
$F_{\pm j}(x)$	two PQ cumulative flow distributions for line j
F(x,y)	2D cumulative distribution function
$\mathcal{F}(x,y)$	2D probability partial density function
G_k	generator k discrete C, FOR and D, DFOR states
G_1+..+G_{Ng}	indicates convolution of discrete states, k=1...Ng
$G_k \bullet F_G$	indicates PQ convolution of k's states into $F_G(x)$
$[G_k \bullet F_G]_{k=1, Ng}$	indicates PQ convolution of all G_k for k=1...Ng
$H_{j,k}$	p.u. line distribution for line j and generator k
INT(x)	next lowest integer value of real number x
Na	Number of load areas
Ng	Number of generators
Nt	Number of transmission lines and transformers
Pr [X > x]	probability random variable X is > real number x
R_j	the MW rating of line j
s_n	area n load+loss MW / total generation MW
xo_j	the top state (base case) line j MW power flow

III. PROCESS FLOW TO REACH A SOLUTION

1. Read all data, scale loads to match total generation supply, solve the load flow, and store the real power line flows.
2. Calculate $F_G(x)$ which is the reliability of generation supply without transmission constraints.
3. Run incremental line flow (load flow) cases in which each generator is outaged and store MW flows in $H_{j,k}$.
4. Run *virtual* generation incremental cases; include in $H_{j,k}$.
5. Adjust dominant $H_{j,k}$ MW flows to improve linearity.
6. Normalize the $H_{j,k}$ table to each k'th source.
7. Discard analysis on lines that will not overload at all.
8. Calculate line flow distributions $F_{\pm j}(y)$.
9. Discard analysis on lines with low overload probability.
10. Choose line j with the highest probability of overload.
11. Create a heuristic load shedding table (LST) for line j.
12. Create a partial $F_j(y)$ for line j using only the $H_{j,k}$ flows causing an increase in overload; ref. as *increasing* flows.
13. Use this partial $F_j(y)$ to initialize F(x,y).
14. Convolve the *decreasing* line flows into F(x,y).
15. Convert F(x,y) to a partial density function $\mathcal{F}(x,y)$.
16. Select a generator-load from the LST to be reduced.
17. Calculate the maximum MW reduction for this generator.
18. Shift the $\mathcal{F}(x,y)$ states as a function of the load shedding.
19. Calculate the incremental changes in $F_G(x)$.
20. Estimate the reduction in loading of other overloaded lines.
21. Repeat steps 17 through 21 until the one overloaded line is no longer overloaded.
22. Repeat steps 10 through 22 until there are no more overloaded lines.

IV. EXACT CONVOLUTION METHOD

A procedure for calculating F_E (x) is given. The solution process is analytically exact and provides a basis for determining the error in the PQ convolution process [4]. The function F_E (x) is a monotone decreasing cumulative distribution that gives the probability of any integer x megawatts or more of generation being out of service The typical network consists of two state and three state generators. G_k generator failure states are defined in Table 1.

Table 1. Two State and Three State Definitions of G_k

$$\text{Up State, Fail State:}\quad G_k = \begin{cases} 1-FOR_k\,, & 0 \text{ MW (up)} \\ FOR_k\,, & C_k \text{ MW (down)} \end{cases} \quad\text{or}\quad \text{Up State, Derated State, Fail State:}\quad G_k = \begin{cases} 1-FOR_k-DFOR_k\,, & 0 \text{ MW (up)} \\ DFOR_k\,, & D_k \text{ MW (derated)} \\ FOR_k\,, & C_k \text{ MW (down).} \end{cases}$$

Then

$$F_E(x) = \Pr[G_1 + G_2 + G_3 + ... + G_{Ng} \text{ (outaged MW)} > x] \quad (1)$$

where Pr is the probability all G_k random outage states is > x MW. Eqn. 1 lacks the structure needed to describe how $F_E(x)$ is to be numerically calculated. $F_E(x)$ is an array of discrete probabilities in one MW x steps starting at 0 MW and ranging up to $x_{max} = \Sigma_{k=1,Ng} C_k$. The initial values are $F_E(0) = 1$ and $F_E(x>0) = 0$. The convolution process is shown in Eqn. 2 for generator k. The left hand side of Eqn. 2 has the new updated values of $F_E(x)$ which replace the $F_E(x)$ at the end of each k'th generator after all x = 0, xmax have been calculated. The real numbers x in a computer program are converted to integers, x = INT(x), and used directly in the computer program array index for $F_E(x)$. Note that any $F_E(x<0) = 1$.

$$[\ F_E(x) = (1 - FOR_k - DFOR_k)\cdot F_E(x) + DFOR_k \cdot F_E(x-D_k) + FOR_k \cdot F_E(x-C_k)\ ]_{x = 0,\, xmax} \quad (2)$$

V. PIECEWISE QUADRATIC CONVOLUTION

The PQ method is described in detail in [4]. The equations presented here are necessary to perform the PQ operations presented in this paper. Fig. 2 illustrates PQ interpolation. Discrete F_G(j·h) points describe the $F_G(x)$ function.

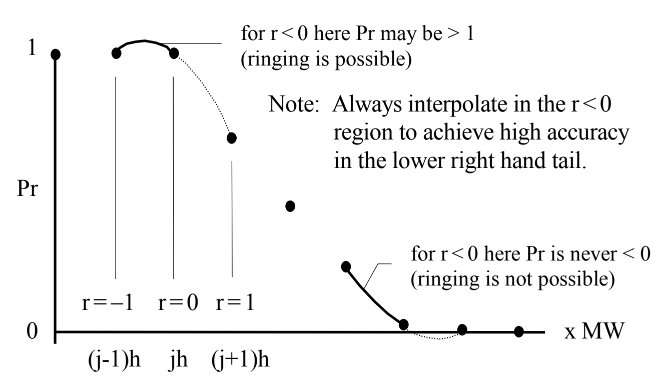

Fig. 2. Piecewise Quadratic Function Interpolation

In a computer program, j is the integer array position, and h is a real number MW increment spacing between the discrete $j-1$, j, and $j+1$ points on the continuous function $F_G(x)$. Let $x = h\cdot(j + r)$ for $-1 < r < 1$. The interpolation equation for calculating continuous real $F_G(x)$ for any real $0 < x < x_{max}$ is

$$F_G[(j+r)\cdot h] = (r/2)\cdot(r-1)\cdot F_G[(j-1)\cdot h] + (1-r^2)\cdot F_G[j\cdot h] + (r/2)\cdot(r+1)\cdot F_G[(j+1)\cdot h]. \qquad (3)$$

Eqn. 4 shows the convolution of generator G_k state(s) into $F_G(x)$ in PQ format. $F_G(x)$ is represented in a computer program as a real array of dimension $[0 : j_{max} \le \text{INT}(h+\Sigma_{k=1,Ng} C_k) / h]$ as discrete values positioned at $F_G(x = j\cdot h)$ where j is calculated using $x = h\cdot(j+r)$. Initially $F_G(0)=.5$ and $F_G(x>0)=0$. In Eqn. 4, any occurrence of $F_G(x<0)=1$. The right hand side of (4) is to be completely evaluated before updating the $F_G(j\cdot h)$ values on the left hand side of the = sign. The interpolation scalars $r_c = (C_k/h) - \text{INT}(C_k/h)$ and $r_d = (D_k/h) - \text{INT}(D_k/h)$ are constant in Eqn. 4 for each k'th generator as well as c_0 ... d_2, j_c, and j_d shown below.

$$c_0 = r_c\cdot(r_c+1)/2 \qquad c_1 = (1-r_c^2) \qquad c_2 = r_c\cdot(r_c-1)/2$$
$$d_0 = r_d\cdot(r_d+1)/2 \qquad d_1 = (1-r_d^2) \qquad d_2 = r_d\cdot(r_d-1)/2$$
$$j_c = \text{INT}(C_k/h) \qquad j_d = \text{INT}(D_k/h).$$

Then Eqn. 4 is

$$\Big[\, F_G\{h\cdot j\} = (1-\text{FOR}_k-\text{DFOR}_k)\cdot F_G\{h\cdot j\} + \text{FOR}_k\cdot\big[c_0\cdot F_G\{h\cdot(j-j_c-1)\} + c_1\cdot F_G\{h\cdot(j-j_c)\} + c_2\cdot F_G\{h\cdot(j-j_c+1)\}\big] + \text{DFOR}_k\cdot\big[d_0\cdot F_G\{h\cdot(j-j_d-1)\} + d_1\cdot F_G\{h\cdot(j-j_d)\} + d_2\cdot F_G\{h\cdot(j-j_d+1)\}\big] \,\Big]_{j=0,\, j_{max}} \qquad (4)$$

Note that $r < 0$ shown in Fig. 2 has been factored into the above equations causing sign changes in Eqn. 4 with respect to Eqn 3. In Eqn. 5, the operator $\bullet$ means a PQ convolution process as described in Eqn. 4. Eqn. 5 is the convolution of all generator states creating $F_G(x)$.

$$[\; F_G(x) = G_k \bullet F_G(x) \;]_{k=1,\, Ng} \qquad (5)$$

An expression for the integral of $F_G(x)$ is given in Eqn. 6. Let j_0 be the discrete point immediately to the left of x. Then $j_0 = \text{INT}(x)$ and $r = x - j_0$. The PQ equation for calculation of expected unserved energy $\text{EUE}(x = \Sigma C_k - y)$ for a period of one hour for a load level of $y = \Sigma C_k - x$ MW is

$$\text{EUE}[x = h\cdot(j+r)] = \int_x^\infty F_G(x)\,dx \text{, or in discrete form is}$$

$$\text{EUE}[x] = \Big[\sum_{j_0}^{j_{max}} F_G\{h\cdot j\} + [-(r^3/6) + (r^2\cdot 3/4) - r - (7/12)]\cdot F_G\{h\cdot j_0\} + [\,(r^3/3) - r^2 + (1/12)]\cdot F_G\{h\cdot(j_0+1)\} + [-(r^3/6) + (r^2/4)]\cdot F_G\{h\cdot(j_0+2)\} \Big]\cdot h \;. \qquad (6)$$

Fig. 3 shows the PQ $F_G(x)$ error in Fig. 1 with respect to the exact $F_E(x)$ distribution for the 286 generator system.

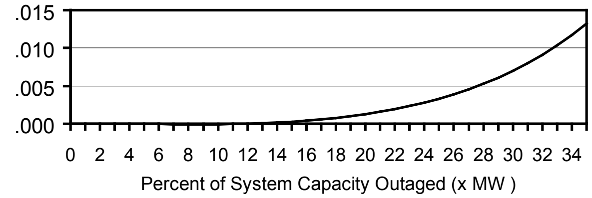

Fig. 3. PU Error of (FG-FE)/FE in Fig. 1. for h=58.197 MW

The error is a function of the h MW grid step size. Table 2 shows how the error at x=10, 20, and 30 percent varies as the h is adjusted by a multiplier of two above and below h=58.197.

Table 2. PQ Error vs h MW Grid Increment and vs x MW Outg.

Outg Cap	F_E Exact h=1 MW	F_G 720 incr h=29.0985	F_G 360 incr h=58.197	F_G 180 incr h=116.394
10%	.5400181	.5400144	.5399837	.5396498
	pu error :	-.0000068	-.0000637	-.0006820
20%	1.70847E-3	1.70889E-3	1.71065E-3	1.72256E-3
	pu error :	.0002452	.0012771	.0082459
30%	1.06976E-8	1.07100E-8	1.07724E-8	1.12558E-8
	pu error :	.0011647	.0069978	.0521781

VI. LOAD FLOW SOLUTION REQUIREMENTS

An initial *top state* load flow is solved using sparse matrix techniques [6,7] in which all the generators are on line and running as constant power sources with no reactive limits. Area bus loads are scaled to equal owned generation capacity plus purchases less sales less area loss. Area interchange is the generation capacity within an area exported to other areas less power imported from other areas. Area loads are scaled each iteration to account for area losses in the top state case.

Generation outage cases are variations of the top state case and total system load is scaled to account for losses. Generation reactive power is unlimited. Autotransformer taps are held constant. A load flow solution tolerance of at least .01 MVA at each bus is recommended to keep cumulative errors small when summing incremental line flows. Care must be taken in the load flow to achieve a high solution accuracy [8].

VII. CALCULATING LINE DISTRIBUTION FACTORS

Real Generators - Using the top state load flow as a reference case, each generator is outaged one at a time. The purpose is to develop a set of $H_{j,k}$ power distribution factors for all $k=1,k_{max}$ generators and all $j=1,N_t$ transmission lines. These are the per unit change in power flow in each line j as a result of loss of generator k. Incremental flows are partitioned into positive and negative sets for each line where positive is arbitrarily one direction for the line and negative is the opposite direction. The sum of all incremental flows on each line will not sum exactly to produce the top state real power line flows. For each line, the directional incremental flows in the direction that is dominant are scaled by a real number multiplier so the sum of all flows will exactly yield the top state flows on each line. Each line is individually scaled. Experience shows this correction is small; about one percent weighted average for the 286 generator system and about one percent for the IEEE Reliability Test System (RTS) [9]. For each line, the adjusted line flows are then normalized to the outaged generators and stored as $H_{j,k}$ line distribution factors. The 286 generator case uses 3.62 megabytes of disk space to store all H factors.

Virtual Generators - The real generation model described in previous paragraphs can only be used to shed load for the entire system. But load shedding across the total system doesn't make sense as a corrective action. Selective load shedding of specific areas or even specific buses associated with specific generators will be required to efficiently unload the overloaded line states. Virtual generators are power injections into selected load buses to effectively reduce load at these buses. The distribution factors for the virtual generators are calculated in the same manner as previously described for real generators and are included in the set of $H_{j,k}$. In setting up the incremental load flow, each k'th virtual generator is made proportional to the real load on each bus in which load shedding is to be executed proportionately on all the load buses selected. The case is solved and incremental line flows are calculated and then normalized. Eqn. 7 shows how linear combinations of normalized $H_{j,k}$ are used to produce new generation to load factors. The m'th terms are real generators and the n'th terms are virtual generators. Virtual generation is used in this probabilistic load flow model to execute heuristic load shedding.

$$[\ H_{j,m\text{-}n} = \ H_{j,m} - H_{j,n}\ ]_{j=1,Nt} \tag{7}$$

VIII. PROBABILISTIC LINE FLOWS

Calculating Line Distributions - The $H_{j,k}$ factors link the k'th generator states in Table 1 with the j'th transmission line flow states in $F_j(x)$. The increase in positive real power flow in line j due to real generator k is $H_{j,k}{\cdot}C_k$. For any line j, the set of generator states in Table 1 combined with $H_{j,k}$ defines the probabilistic line flow states $F_j(x)$ as shown in Eqn. (8).

$$\Big[F_j(x) = [\ (-H_{j,k}{\cdot}G_k){\bullet}F_j(x)\ ]_{k=1,Ng}\Big]_{j=1,Nt} \tag{8}$$

The $-H_{j,k}$ indicates that flow states are to be removed from $F_j(x)$ as generators are outaged. In the top state, all the line flows due to all the generators are already included and sum to xo_j for each j'th line. $F_j(x)$ is initialized for the top state as $F_j(x < xo_j) = 1$, $F_j(x > xo_j) = 0$, and $F_j(x = i{\cdot}h_j) = r$. Where i is the discrete point below xo_j according to $i = INT(xo_j/h_j - .5 + b)$ and $h_j = (xmax_j - xmin_j)/(\text{number of grid increments})$. Then $r = xo_j/h_j - .5 + b - i$ and b is a shifter to keep $xmax_j$ and $xmin_j$ within the range of the discrete array. Setting up PQ is covered in more detail in [4]. Eqn. 8 will only produce low error on the lower right hand tail of $F_j(x)$. In order to model negative flow line overload states accurately, the line direction will need to be reversed and Eqn. 8 repeated. This means that line j can have a second $F_j(x)$ in which the line flows have been reversed and the line overload is in the negative direction. The -j in $F_{-j}(x)$ is used to signify convolution $F_j(x)$ with flows reversed for line j.

Screening Lines - Many lines will not overload for any generation state or will have overloads of such low probability that their contribution to the EUE is insignificant. Lines with $xmax_j < R_j$ and $xmin_j > -R_j$ can be discarded from further analysis since there are no generation failure states resulting in overload. Lines with small $F_j(x = R_j) < 10^{-12}$ can also be discarded.

IX. REMOVING LINE OVERLOADS

A set of $F_{\pm j}(x)$ line distributions are produced as a result of executing steps 1 - 8 listed in section III. Steps 9 - 20 are expanded below to show how load shedding is calculated.

9. Discard lines with $Pr[X_j > R_j] = F_{\pm j}(x = R_j) < 10^{-12}$ and rank the remaining lines in descending order of $Pr[X_j > R_j]$.

10. Select line j with the highest $F_{\pm j}(x = R_j)$.

11. Build a heuristic load shedding table for line j. The LST is created as a list of decreasing positive $H_{j,m\text{-}n}$ for line j. Note that the LST is usually not unique. For example, a generator supplying power to several companies with an overloaded stepup transformer could have the load shedding assigned to any of the companies with nearly identical results.

12. Create a partial $F_j(y)$ for line j using only the $H_{j,k}$ flows causing an increase in overload which are called the line overload *increasing* flows. The *decreasing* incremental flows reduce the probability of overload but do not reduce $xmax_j$.

13. Use the partial $F_j(y)$ created in 12 to initialize F(x,y). First, set all of the two dimensional array F(x,y) to zero. Function F(x,y) = Pr[generation MW available > x and line flow MW>y]. The x axis ranges from x_1 = sum of *increasing* generation MW to x_2 = sum of all generation. The y axis ranges from $y_1 = R_j$ line rating to $y_2 = ymax_j$. Then set $F(x_1,y) = F_j(y)$ for all $y_1 < y < y_2$. The grid MW spacing of F(x,y) will be determined by the x and y ranges and the number of increments selected. The size of F(x,y) affects solution accuracy versus execution speed. x~360 and y~50 increments have been found to give good results.

14. Convolve *decreasing* line flows into F(x,y). A piecewise linear equation for performing this operation is given in Eqn. 9 for line j and generator k (two states).

$$F(x,y)_{after} = F(x\,,y)_{before}{\cdot}FOR_k + F(x - C_k\,, y + (H_{j,k}{\cdot}C_k))_{before}{\cdot}(1 - FOR_k) \tag{9}$$

The generator outage state is not shifted. The generator available state is shifted downward and to the right. In the process of shifting outage and derated states, an interpolation must be performed between discreet points of F(x,y). A linear interpolation is made of the four adjacent points using relative r_x and r_y where $0 < r_x < 1$ and $0 < r_y < 1$ between grid increments.

15. Convert F(x,y) to a partial density function *F*(x,y) as shown in Eqn 10. This is performed after all the decreasing line flow generators have been convolved into F(x,y). The i and j are discrete points in (10) increasing to the right and upward.

$$[\ \mathcal{F}(i,j) = F(i,j) - F(i+1,j)\ ]_{\text{for all } i \text{ and } j} \tag{10}$$

16. Select the next entry in the LST. This will be generator m and load area n that will decrease the loading on the overloaded line j the fastest while minimizing the amount of load shed.

17. Calculate the maximum MW generator m will be reduced (a heuristic) based on constraints of 1) line overload needing reduction, 2) generation capacity available for reduction, and 3) maximum load that can be reduced. If H values are << 1 the user should review the LST to see if load shedding loads and generation listed are appropriate for line j.
18. Shift the $F(x,y)$ states as a function of the load shedding. For generator m and load n, $H_{j,m\text{-}n}$ is the slope of a line in the x-y plane of $F(x,y)$. If a Δy_j line flow is reduced due to an m-n reduction, then all the states in $F(x,y)$ are shifted $\Delta x=\Delta y_j/H_{j,m\text{-}n}$. Fig. 4 illustrates the concept of how to shift $F(x,y)$ states.

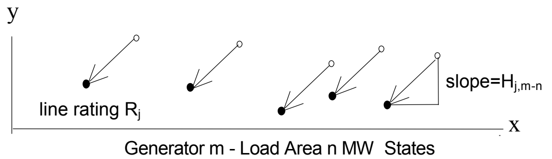

Figure 4. Shift in $F(x,y)$ States to Unload Line j

19. Calculate the incremental changes in $F_G(x)$. This is performed by observing the change in $F(x,y=R_j)$ before and after a Δy_j shift in line j flows. The $F(x,y=R_j)$ values **before** a Δy_j shift are subtracted from a temporary function $T(x)$ that has the same x scale as $F_G(x)$. **After** a Δy_j shift is performed on $F(x,y)$ as shown in step 18, the new shifted values in $F(x,y=R_j)$ are added to $T(x)$. The x axis in $F_G(x)$ ranges from installed generation capacity downward while the x axis in $F(x,y)$ is the opposite with installed capacity on the upper end of the x range. The x and x have different scales but any point on one can be mapped to the other using a linear conversion formula and interpolation of either of the functions. After a series of Δy_j increments (repeating steps 16-19) have unloaded line j completely, the $T(x)$ is integrated (summed) from 0 MW up to the total capacity with each $T(x)$ point being the integrated value of $T(x)$ up to that point. Then $F_G(x) = F_G(x)+T(x)$ to capture the increased amount of unavailable generation capacity due to the line j transmission constraint. This is the total system $F_G(x)$ with line constraints. Set up separate $T_n(x)$ to capture load shedding for each n'th area in accordance with the LST load entries. Use s_n= (area n load+loss MW / total generation MW) to scale the MW levels in $F_G(x)$ for individual n'th area load sheddings.
20. Estimate the reduction in loading of other overloaded lines. This is a heuristic for unloading jointly overloaded lines. An example is two overloaded lines electrically in series or parallel. The generation and load that unloads one line also unloads the other. The $F_k(x)$ $(k\neq j)$ line distribution functions could be shifted downward to account for joint unloadings. A better approach is to increase the R_k ratings. Let Δx_k be the R_k MW shift of line k rating due to a Δx_j small increment unloaded in line j. If $F_k(R_k)<F_j(R_j)$ then $\Delta x_k\approx \Delta x_j\cdot(H_{k,m\text{-}n}/H_{j,m\text{-}n})$. If $F_k(R_k)>F_j(R_j)$, then $\Delta x_k\approx\Delta x_j\cdot(H_{k,m\text{-}n}/H_{j,m\text{-}n})\cdot[F_k(R_k)/F_j(R_j)]$. Note that all line ratings are updated as $R_j=R_j+\Delta x_j$ and $R_k=R_k+\Delta x_k$ for each Δx_j increment unloaded. $F_j(x)$ is never shifted.

The above processes are repeated in small line flow increments using steps 17 through 21 until there are no more overloaded lines. Transmission EUE is calculated as the difference in $F_G(x)$ EUE before and after $T(x)$. Transmission LOLP within an h MW interval is the difference in transmission EUE divided by h. Generation and transmission EUE and LOLP can be displayed in small incremental percentage steps.

X. TEST CASE USING IEEE RTS

An example is presented using the IEEE Reliability Test System [9]. The RTS is divided into three load areas, North (buses 14-22), Central (buses 3,4,6,9-13,23,24), and South (buses 1,2,5,7,8). A full enumeration linear program LP model is used as a benchmark to test the accuracy of the convolution method. In order to keep the full enumeration run time reasonable, generators are combined at each load flow bus The RTS has no overloaded lines when all lines are in service. All lines in the RTS are derated to create overloads. Results of the tests are shown in Figs. 5 and 6 below for line deratings to 80%, 60% and 40% of normal.

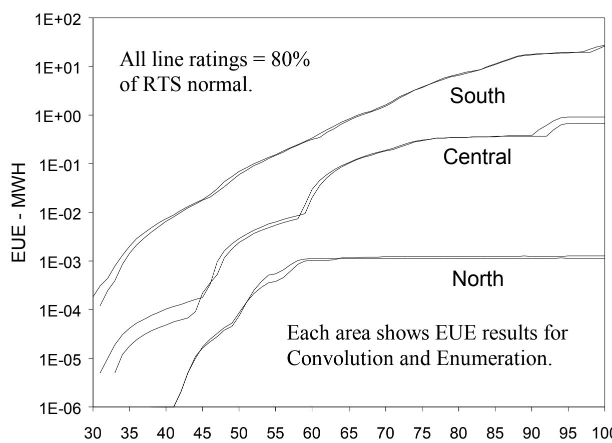

Fig. 5. RTS Transmission EUE vs Percent Load For Each Area

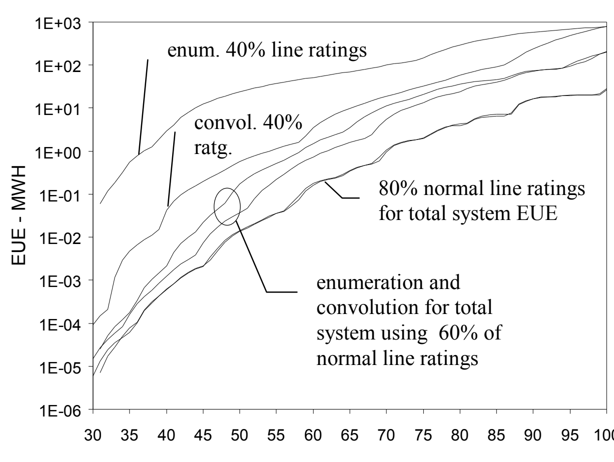

Fig. 6. Total Transmission EUE vs Percent Loading For All Lines

The 80% line ratings case has probabilistically overloaded lines 6-10 122%, 7-8 201%, 8-9 126%, 8-10 112%, 14-16 118%, 16-17 116%, and 16-19 106%. The convolution heuristic gives excellent results for this 80% case. However, the 40% line ratings case shows that the convolution heuristic calculates too small a transmission EUE compared with the LP when all lines are heavily overloaded (in both directions). This is due to the step 20 process of unloading lines using only the *increasing* line flows (increasing in both directions). Step 20 assumes the generator-load combinations causing incremental line flows in opposite directions are too weakly coupled to be of significance. This is true only when the transmission system is reliable with low probabilities of lines being overloaded.

XI. LARGE SYSTEM PLANNING EXAMPLE

A second example is presented showing how the convolution method presented in this paper has been applied to a real planning problem at the City of Austin Electric Utility Department (COA). The COA system is a ~1700 MW peak demand 69 kV and 138 kV system connected through a number of 480 MVA autotransformers to the ERCOT (Electric Reliability Council of Texas) 345 kV system. The ERCOT system load flow and generator reliability planning data bases have ~ 300 generators, 4200 buses, and 5200 lines. It is a large system in the sense that the generator and line outage states are far too numerous to be enumerated.

The reliability of the COA system is highly dependent on its autotransformers to supply emergency reserve power from ERCOT as well as 950 MW COA owned generation on the 345 kV grid. The autotransformers become more critical when a 550 MW plant (Holly) centrally located in the COA system is retired in a few years. Presently the COA has two bulk transmission substations, Austrop and Lytton. Each station has two 345/138 kV autotransformers. A third 345 kV substation called Garfield has been constructed and will soon be energized with one 480 MVA autotransformer. Fig. 7 shows the layout.

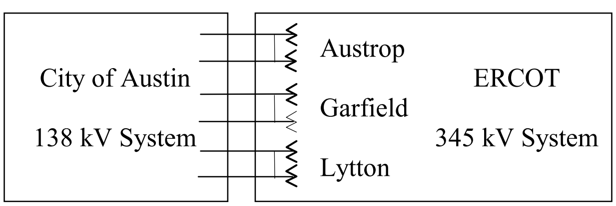

Fig. 7 City of Austin 345/138 kV 480 MVA Autotransformers

The COA power supply reliability is a function of the ERCOT power supply reliability and the reliability of the transmission network delivering the ERCOT power. Any autotransformer outages are severe because they are few in number in the COA system and because their repair time is long. The COA autotransformer catastrophic failure experience is consistent with [10]. For study purposes a pessimistic autotransformer forced outage rate of 4% is used. The study is repeated using a more optimistic 2% autotransformer FOR to see if the study results are sensitive to the FOR value chosen.

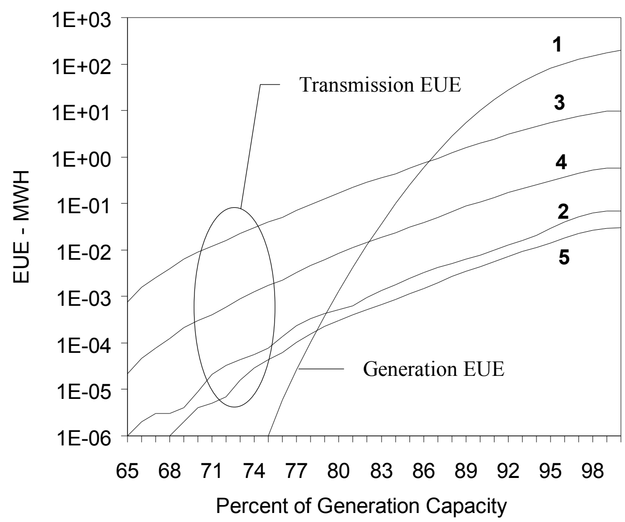

Fig. 8 COA EUE With Autotransformer FOR=.04

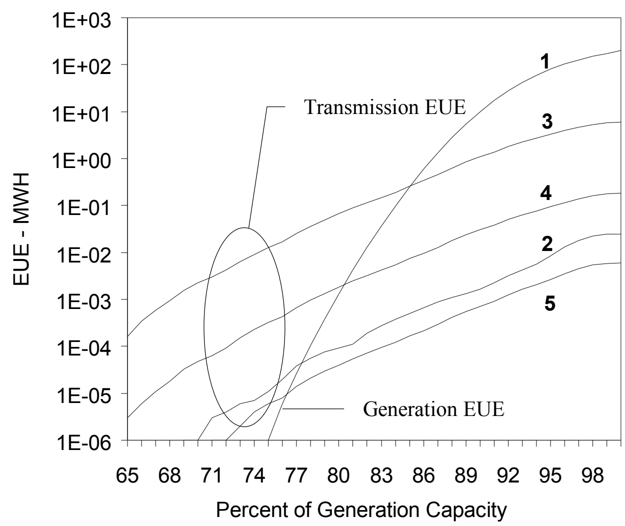

Fig. 9 COA EUE With Autotransformer FOR=.02

Figs. 8 and 9 show the additional EUE caused by autotransformer failures for all COA autotransformer outages through N-3. Up to 60 lines in the COA system are monitored for probabilistic overload. Approximately 10^{90} generation states are modeled.

Curve 1 is the generation supply EUE available to the COA with no transmission constraints. Curve 2 represents the additional transmission EUE with Holly not retired and with no Garfield autotransformers. Curve 3 shows the increase in EUE with Holly retired. Curves 4 and 5 show the progressive decrease in transmission EUE as one and two autotransformers are added to the Garfield substation when Holly is retired. The study shows that two autotransformers at Garfield bring the reliability back to about the same level as before Holly is retired. This holds true for both the 4% and 2% autotransformer FOR as shown in Figs. 8 and 9.

XI. CONCLUSIONS

The objective of this project is to develop a new multi-area composite generation/transmission reliability model based on convolution techniques. Convolution can cover the entire set of outage events if it can be implemented at all. Desirable features include: 1) a full transmission network, 2) solution times of no more than a few hours for a large system, and 3) the ability to dissect a network so completely that even relatively inexperienced engineers can easily identify transmission constraints and their impact on reliability.

The model presented in this paper is close to satisfying the desired objectives. A problem still exists in the use of a heuristic to perform load shedding. A future paper will be needed if a better solution can be found. A line outage model was not presented here but it has been developed and will be presented later as an extension to this paper. Even without a line outage model, transmission states can be explicitly enumerated.

The authors believe the methods presented in this paper represent an important advancement to the present state of knowledge concerning the assessment of power system reliability.

XII. REFERENCES

[1] C. K. Pang and A. J. Wood, *Multi-Area Generation System Reliability Calculations*, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-94, pp. 508-517, Mar/Apr 1975.

[2] J. Mitra and C. Singh, *Incorporating the DC Load Flow Model in the Decomposition-Simulation Method of Multi-Area Reliability Evaluation*, Paper No. 95 SM 511-6 PWRS, IEEE/PES Summer Meeting, Portland, Oregon, July 1995.

[3] E. Becker, G. Carey, and J. Oden, <u>Finite Elements, An Introduction</u>, Englewood Cliffs, NJ: Prentice-Hall, 1981, p 66.

[4] E. Preston and M. Grady, *An Efficient Method for Calculating Power System Production Cost and Reliability*, IEE Proceedings-C, Vol. 138, No. 3, May 1991.

[5] G. Anders, <u>Probabilistic Concepts in Electric Power Systems</u>, Wiley, New York, 1990, pp. 282-285.

[6] K. Zollenkopf, *Bi-Factorisation Basic Computational Algorithm and Programming Techniques*, a paper from <u>Large Sparse Sets of Linear Equations</u>, edited by J. K. Reid, Academic Press, 1971, pp. 75-96.

[7] W. F. Tinney and J. W. Walker, *Solutions of Sparse Network Equations by Optimally Ordered Triangular Factorization*, Proc. IEEE, 55 (1967), 1801-1809.

[8] Y. Beers, <u>Introduction to the Theory of Error</u>, Reading, MA: Addison-Wesley Publishing Company, Inc., 1962, pp. 3,4.

[9] IEEE Committee Report, *IEEE Reliability Test System*, IEEE Trans. PAS, Vol. 98, No. 6, pp. 2047-2054, Nov/Dec 1979.

[10] B. Silverstein and D. Porter, *Contingency Ranking for Bulk System Reliability Criteria*, IEEE Trans. PWRS, Vol. 7, No. 3, pp. 956-962, August 1992.

XIII. 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 is currently working toward his Ph.D. in Electrical Engineering at The University of Texas in Austin.

Mr. Preston is presently Manager of the System Analysis division at the City of Austin Electric Utility and is a registered Professional Engineer in the State of Texas.

Martin L. Baughman, (SM,72), was born on February 18, 1946 in Paulding, Ohio. He received his BS in Electrical Engineering from Ohio Northern University in 1968 and his MS in Electrical Engineering and Ph.D. degrees in Electrical Engineering at MIT in 1970 and 1972, respectively.

Dr. Baughman was a Research Associate at Massachusetts Institute of Technology from 1972 to 1975, at which time he joined the University of Texas at Austin as a Senior Research Associate. In 1976 he joined the faculty of the Department of Electrical and Computer Engineering as an Assistant Professor. In 1979 he co-authored a book with Paul Joskow on electricity supply planning entitled <u>Electricity in the United States: Models and Policy Analysis</u>. From 1984 to 1986 he chaired the National Research Council Committee on Electricity in Economic Growth.

Dr. Baughman is a member of the International Association of Economists and is a registered Professional Engineer in the State of Texas.

W. Mack Grady, (SM,83), was born on January 5, 1950, in Waco, Texas. He received his BS in Electrical Engineering degree from The University of Texas at Arlington in 1971 and his MS in Electrical Engineering and Ph.D. degrees from Purdue University in 1973 and 1983, respectively.

Dr. Grady is a professor of Electrical and Computer Engineering at the University of Texas at Austin. His areas of interest include power system analysis harmonics, and power quality. He chairs the IEEE T&D General Systems Subcommittee, and is a registered professional engineer in Texas.