IEEE RELIABILITY TEST SYSTEM

A report prepared by the Reliability Test System Task Force of the Application of Probability Methods Subcommittee*

ABSTRACT

This report describes a load model, generation system, and transmission network which can be used to test or compare methods for reliability analysis of power systems. The objective is to define a system sufficiently broad to provide a basis for reporting on analysis methods for combined generation/transmission (composite) reliability.

The load model gives hourly loads for one year on a per unit basis, expressed in chronological fashion so that daily, weekly, and seasonal patterns can be modeled. The generating system contains 32 units, ranging from 12 to 400 MW. Data is given on both reliability and operating costs of generating units. The transmission system contains 24 load/generation buses connected by 38 lines or autotransformers at two voltages, 138 and 230 kV. The transmission system includes cables, lines on a common right of way, and lines on a common tower. Transmission system data includes line length, impedance, ratings, and reliability data.

INTRODUCTION

There has been a continuing and increasing interest in methods for power system reliability evaluation. In order to provide a basis for comparison of results obtained from different methods, it is desirable to have a reference or "test" system which incorporates the basic data needed in reliability evaluation. The purpose of this report is to provide such a "reliability test system".

The report describes a load model, generation system, and transmission network. The objective is to define a system sufficiently broad to provide a basis for reporting on analysis methods for combined generation/transmission (composite) reliability methods. It is not practical to specify all the parameters needed for every application. The goal is to establish a core system which can be supplemented by individual authors with additional or modified parameters needed in a particular application. For example, the reliability test system as reported in this paper does not include data on the following:

- Substation configuration at load/generation buses
- Distribution system configuration
- Interconnections with other systems
- Protective relay configurations
- Future expansion, such as load growth, future unit sizes, types, and reliability.

The Electric Power Research Institute (EPRI) has recently reported data on synthetic electric utility systems [1]. These contain much larger systems than the one in this report. They are designed primarily for use in evaluation of alternate technologies.

A smaller test system was developed by the CIGRE Working group 01 of Study Committee No. 32 [2]. But that system was judged too small and incomplete to be applicable as a model in reliability analysis, especially when considering composite systems.

DESCRIPTION OF RELIABILITY TEST SYSTEM

Load Model

The annual peak load for the test system is 2850 MW.

Table 1 gives data on weekly peak loads in per cent of the annual peak load. The annual peak occurs in week 51. The data in Table 1 shows a typical pattern, with two seasonal peaks. The second peak is in week 23 (90%), with valleys at about 70% in between each peak. If week 1 is taken as January, Table 1 describes a winter peaking system. If week 1 is taken as a summer month, a summer peaking system can be described.

Table 1
Weekly Peak Load in Percent of Annual Peak

Week	Peak Load	Week	Peak Load
1	86.2	27	75.5
2	90.0	28	81.6
3	87.8	29	80.1
4	83.4	30	88.0
5	88.0	31	72.2
6	84.1	32	77.6
7	83.2	33	80.0
8	80.6	34	72.9
9	74.0	35	72.6
10	73.7	36	70.5
11	71.5	37	78.0
12	72.7	38	69.5
13	70.4	39	72.4
14	75.0	40	72.4
15	72.1	41	74.3
16	80.0	42	74.4
17	75.4	43	80.0
18	83.7	44	88.1
19	87.0	45	88.5
20	88.0	46	90.9
21	85.6	47	94.0
22	81.1	48	89.0
23	90.0	49	94.2
24	88.7	50	97.0
25	89.6	51	100.0
26	86.1	52	95.2

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Table 2 gives a daily peak load cycle, in per cent of the weekly peak. The same weekly peak load cycle is assumed to apply for all seasons. The data in Tables 1 and 2, together with the annual peak load define a daily peak load model of 52x7 = 364 days, with Monday as the first day of the year.

Table 2
Daily Peak Load in Percent of Weekly Peak

Day	Peak Load
Monday	93
Tuesday	100
Wednesday	98
Thursday	96
Friday	94
Saturday	77
Sunday	75

Table 3 gives weekday and weekend hourly load models for each of three seasons. A suggested interval of weeks is given for each season. The first two columns reflect a winter season (evening peak), while the next two columns reflect a summer season (afternoon peak). The interval of weeks shown for each season in Table 3 represents application to a winter peaking system. If Table 1 is started with a summer month, then the intervals for application of each column of the hourly load model in Table 3 should be modified accordingly.

Table 3
Hourly Peak Load in Percent of Daily Peak

	Winter Weeks 1-8 & 44-52		Summer Weeks 18-30		Spring/Fall Weeks 9-17 & 31-43	
Hour	Wkdy	Wknd	Wkdy	Wknd	Wkdy	Wknd
12-1am	67	78	64	74	63	75
1-2	63	72	60	70	62	73
2-3	60	68	58	66	60	69
3-4	59	66	56	65	58	66
4-5	59	64	56	64	59	65
5-6	60	65	58	62	65	65
6-7	74	66	64	62	72	68
7-8	86	70	76	66	85	74
8-9	95	80	87	81	95	83
9-10	96	88	95	86	99	89
10-11	96	90	99	91	100	92
11-Noon	95	91	100	93	99	94
Noon-1pm	95	90	99	93	93	91
1-2	95	88	100	92	92	90
2-3	93	87	100	91	90	90
3-4	94	87	97	91	88	86
4-5	99	91	96	92	90	85
5-6	100	100	96	94	92	88
6-7	100	99	93	95	96	92
7-8	96	97	92	95	98	100
8-9	91	94	92	100	96	97
9-10	83	92	93	93	90	95
10-11	73	87	87	88	80	90
11-12	63	81	72	80	70	85

Wkdy = Weekday, Wknd = Weekend

Combination of Tables 1, 2, and 3 with the annual peak load defines an hourly load model of 364x24 = 8736 hours. The annual load factor for this model can be calculated as 61.4%.

Generating System

Table 4 gives a list of the generating unit ratings and reliability data. In addition to forced outage rate, the parameters needed in frequency and duration calculations are given (MTTF and MTTR). Table 4 gives data on full outages only. Generating units can also experience partial outages, both forced and scheduled. Partial outages can have a significant effect on generation reliability. However, modeling of partial outages can be done in many ways; and no single approach has achieved widespread use over all others. Therefore the task force elected to leave partial outage data as a parameter to be specified for a particular application.

Table 4
Generating Unit Reliability Data

Unit Size MW	Number of Units	Forced Outage Rate(3)	MTTF(1) hrs.	MTTR(2) hrs.	Scheduled Maintenance wks/year
12	5	0.02	2940	60	2
20	4	0.10	450	50	2
50	6	0.01	1980	20	2
76	4	0.02	1960	40	3
100	3	0.04	1200	50	3
155	4	0.04	960	40	4
197	3	0.05	950	50	4
350	1	0.08	1150	100	5
400	2	0.12	1100	150	6

NOTES:

(1) MTTF = mean time to failure

(2) MTTR = mean time to repair

(3) Forced outage rate = $\frac{\text{MTTR}}{\text{MTTF + MTTR}}$

The generation mix is as shown below:

	MW	%
Steam:		
Fossil-oil	951	28
Fossil-coal	1274	37
Nuclear	800	24
Combustion Turbine	80	2
Hydro	300	9
Total	3405	100

Table 5 gives operating cost data for the generating units. For power production, data is given in terms of heat rate at selected output levels, since fuel costs are subject to considerable variation due to geographical location and other factors. The following fuel costs are suggested for general use (1979 base).

#6 oil	\$2.30/MBtu
#2 oil	\$3.00/MBtu
coal	\$1.20/MBtu
nuclear	\$0.60/MBtu

Table 5
Generating Unit Operating Cost Data

Size MW	Type	Fuel	Output %	Heat Rate Btu/kWh	O&M Cost Fixed $/kW/YR	O&M Cost Variable $/MWh
12	Fossil Steam	#6 oil	20	15600	10.0	0.90
			50	12900		
			80	11900		
			100	12000		
20	Combus. Turbine	#2 oil	80	15000	0.30	5.00
			100	14500		
50	Hydro	SEE TABLE 6				
76	Fossil Steam	Coal	20	15600	10.0	0.90
			50	12900		
			80	11900		
			100	12000		
100	Fossil Steam	#6 oil	25	13000	8.5	0.80
			55	10600		
			80	10100		
			100	10000		
155	Fossil Steam	Coal	35	11200	7.0	0.80
			60	10100		
			80	9800		
			100	9700		
197	Fossil Steam	#6 oil	35	10750	5.0	0.70
			60	9850		
			80	9840		
			100	9600		
350	Fossil Steam	Coal	40	10200	4.5	0.70
			65	9600		
			80	9500		
			100	9500		
400	Nuclear Steam	LWR	25	12550	5.0	0.30
			50	10825		
			80	10170		
			100	10000		

The operating and maintenance (O&M) costs are also intended to apply to 1979. For hydro units, data on capacity and energy limitations is given in Table 6.

Table 6
Hydro Capacity and Energy

Quarter	Capacity Available (1) %	Energy Distribution (2) %
1	100	35
2	100	35
3	90	10
4	90	20

NOTES:

(1) 100% capacity = 50 MW

(2) 100% energy = 200 GWh

Transmission System

The transmission network consists of 24 bus locations connected by 38 lines and transformers, as shown in Figure 1. The transmission lines are at two voltages, 138 kV and 230 kV. The 230 kV system is the top part of Figure 1, with 230/138 kV tie stations at buses 11, 12, and 24.

The locations of the generating units are shown in Table 7. It can be seen that 10 of the 24 buses are generating stations. Table 8 gives data on generating unit MVAr capability for use in load flow calculations.

Table 7
Generating Unit Locations

Bus	Unit 1 MW	Unit 2 MW	Unit 3 MW	Unit 4 MW	Unit 5 MW	Unit 6 MW
1	20	20	76	76		
2	20	20	76	76		
7	100	100	100			
13	197	197	197			
15	12	12	12	12	12	155
16	155					
18	400					
21	400					
22	50	50	50	50	50	50
23	155	155	350			

Table 8
Generating Unit MVAr Capability

Size MW	MVAr Minimum	MVAr Maximum
12	0	6
20	0	10
50	-10	16
76	-25	30
100	0	60
155	-50	80
197	0	80
350	-25	150
400	-50	200

The system has voltage corrective devices at bus 14 (synchronous condenser) and bus 6 (reactor). Table 9 gives the MVAr capability of these devices. These devices increase the ability of the test system to maintain rated voltage, particularly under some contingency conditions. The amount of such correction capability provided is a system design parameter, which depends partly on the criteria chosen for acceptable voltage limits.

Table 9
Voltage Correction Devices

Device	Bus	MVAr Capability
Synchronous condenser	14	50 Reactive 200 Capacitive
Reactor	6	100 Reactive

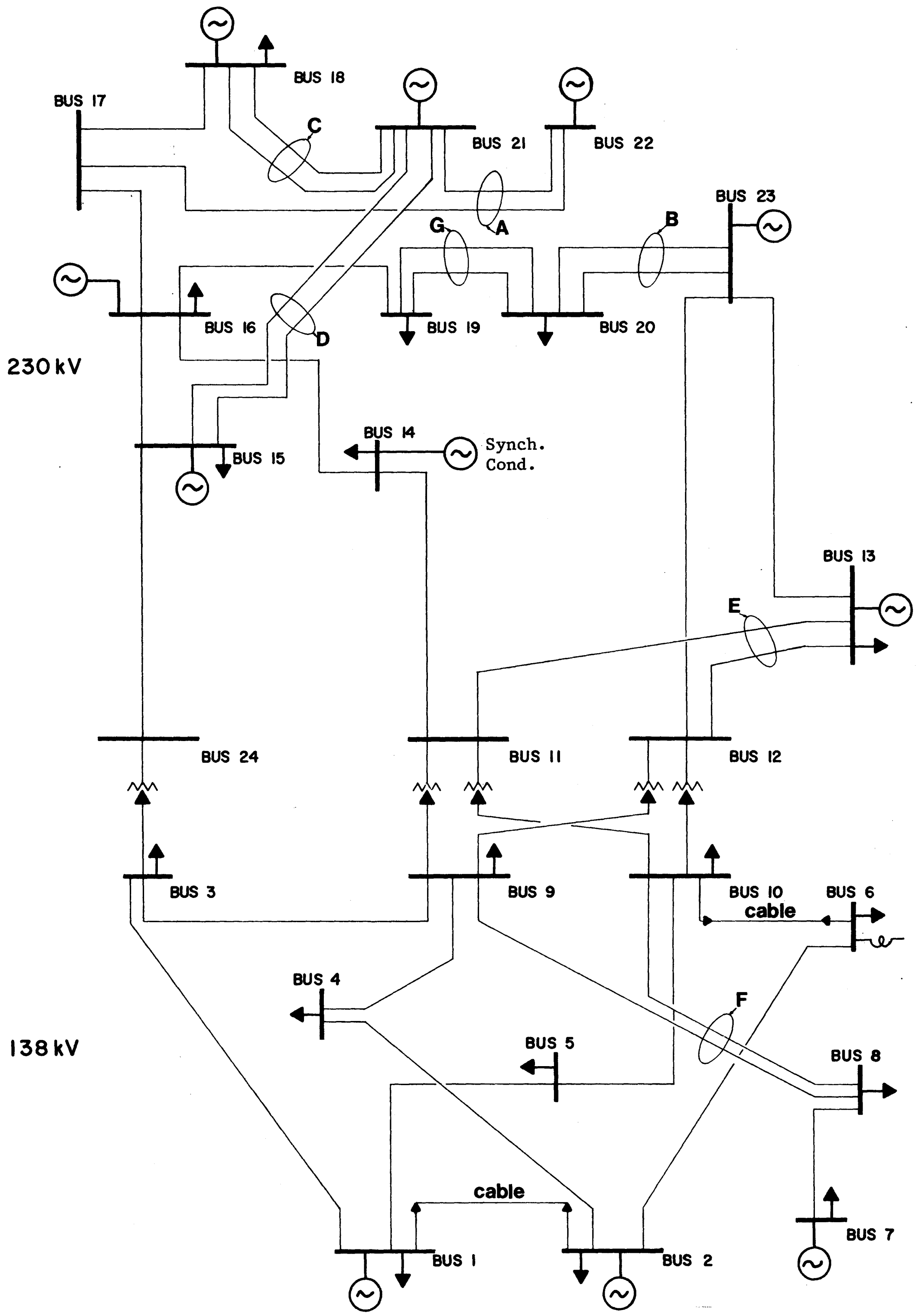

Figure 1 - IEEE Reliability Test System

Bus load data at time of system peak is shown in Table 10. No data on load uncertainty or load diversity between buses is provided. For times other than the annual system peak, the bus loads are assumed to have the same proportional relation to system load as at the peak load conditions. The per unit bus loads are given in the last column of Table 10. For MVAr requirements, a 98% power factor is assumed. This corresponds to an MVAr requirement of approximately 20% of the MW load at each bus. The 98% power factor is assumed to apply at all load levels. These restrictions on bus loads (no uncertainty, no diversity, constant power factor) are the assumptions usually made in reliability evaluations. It will be of interest to compare results obtained with these assumptions with those from less restrictive models.

Table 10
Bus Load Data

Bus	Load MW	Load MVAr	Bus Load % of System Load
1	108	22	3.8
2	97	20	3.4
3	180	37	6.3
4	74	15	2.6
5	71	14	2.5
6	136	28	4.8
7	125	25	4.4
8	171	35	6.0
9	175	36	6.1
10	195	40	6.8
13	265	54	9.3
14	194	39	6.8
15	317	64	11.1
16	100	20	3.5
18	333	68	11.7
19	181	37	6.4
20	128	26	4.5
TOTAL	2850	580	100.0

Transmission network connection data is defined by Figure 1. Although no attempt has been made to define actual geographical layout, the physical bus locations on Figure 1 are fairly consistent with the line lengths, which are shown in Table 11. Buses 9, 10, 11 and 12 are at a single physical location (stepdown station); buses 3 and 24 are also at a single location. As noted on Figure 1, the connections from bus 1 to 2 and from bus 6 to 10 are 138 kV cables.

Transmission line forced outage data is given in Table 11. Permanent outages are those which require component repair in order to restore the component to service.[3] Therefore, for permanent outages both outage rate and outage duration are shown. Transient outages are those which are not permanent. These include both automatic and manual reclosing.[3] For transient forced outages, only the outage rate is given, since the outage duration is very short. In specific applications, transmission line forced outage rates (particularly for transient outages) are dependent on geographical location as well as other factors. The data in Table 11 is representative of experience in the United States and Canada.

The term "outage rate" has been applied in keeping with current industry practice. Unfortunately, the term has a different meaning for generating units than for transmission equipment. For generating units, forced outage rate refers to the <u>probability</u> of forced outage at a random point in time between scheduled outages. This is the meaning of forced outage rate in Table 4. For transmission equipment, the term "outage rate" is commonly used to describe the <u>number</u> of outages per unit of exposure time [3]. This is the meaning of outage rate in Table 11 and subsequent tables.

Table 11
Transmission Line Length and Forced Outage Data

From Bus	To Bus	Length miles	Permanent Outage Rate 1/yr	Permanent Outage Duration Hours	Transient Outage Rate 1/yr
1	2	3	.24	16	0.0
1	3	55	.51	10	2.9
1	5	22	.33	10	1.2
2	4	33	.39	10	1.7
2	6	50	.48	10	2.6
3	9	31	.38	10	1.6
3	24	0	.02	768	0.0
4	9	27	.36	10	1.4
5	10	23	.34	10	1.2
6	10	16	.33	35	0.0
7	8	16	.30	10	0.8
8	9	43	.44	10	2.3
8	10	43	.44	10	2.3
9	11	0	.02	768	0.0
9	12	0	.02	768	0.0
10	11	0	.02	768	0.0
10	12	0	.02	768	0.0
11	13	33	.40	11	0.8
11	14	29	.39	11	0.7
12	13	33	.40	11	0.8
12	23	67	.52	11	1.6
13	23	60	.49	11	1.5
14	16	27	.38	11	0.7
15	16	12	.33	11	0.3
15	21	34	.41	11	0.8
15	21	34	.41	11	0.8
15	24	36	.41	11	0.9
16	17	18	.35	11	0.4
16	19	16	.34	11	0.4
17	18	10	.32	11	0.2
17	22	73	.54	11	1.8
18	21	18	.35	11	0.4
18	21	18	.35	11	0.4
19	20	27.5	.38	11	0.7
19	20	27.5	.38	11	0.7
20	23	15	.34	11	0.4
20	23	15	.34	11	0.4
21	22	47	.45	11	1.2

The permanent forced outage rates in Table 11 were calculated as follows:

138 kV lines: $\lambda_p = 0.52\ L + 0.22$

230 kV lines: $\lambda_p = 0.34\ L + 0.29$

138 kV cables: $\lambda_p = 0.62\ L + 0.226$

where L is the length of the line or cable in 100 miles. The constant in each equation accounts for faults on terminal equipment switched with the line (including bus sections, but excluding circuit breakers).

The permanent outage duration data in Table 11 is a combination of permanent outage duration data for lines (or cables) and terminal equipment. The separate outage durations used to obtain Table 11 were as follows:

Equipment	Permanent outage duration, hours Line/Cable	Terminal
138 kV line	9	11
230 kV line	18	8
138 kV cable	96	9

The outage duration values in Table 11 were developed by use of the following equation:

$$R = (\lambda_1 R_1 + \lambda_2 R_2)/(\lambda_1 + \lambda_2)$$

where

λ_1, R_1 = Line/cable outage rate and outage duration.

λ_2, R_2 = Terminal outage rate and outage duration.

Rather than calculating a different repair time for each line, the average line length in the test system for each of the two voltages was used to calculate a single (average) value of λ_1. From this, the average outage duration for each voltage level was calculated. For the two cables, separate repair times were calculated by use of the actual cable length.

The transformer outage duration in Table 11 is 768 hours, which corresponds to 32 days. In a particular situation, transformer outage duration will be greatly influenced by whether or not a spare transformer is available.

The transient forced outage rates in Table 11 were calculated as follows:

138 kV lines: $\lambda_t = 5.28\ L$

230 kV lines: $\lambda_t = 2.46\ L$

It is assumed that transient outages occur only on transmission lines. Hence, no constant term for terminal outages is included, and the transient outage rate for transformers and cables is taken to be zero.

Outages on substation components which are not switched as a part of a line are not included in the outage data in Table 11. For bus sections, the following data is provided:

	138 kV	230 kV
Faults per bus section-year	0.027	0.021
Percent of faults permanent	42	43
Outage duration for permanent faults, hours	19	13

For circuit breakers, the following statistics are provided:

Physical failures/breaker year	0.0066
Breaker operational failure, per breaker year	0.0031
Outage Duration, hours	72

A physical failure is a mandatory unscheduled removal from service for repair or replacement. An operational failure is a failure to clear a fault within the breaker's normal protection zone.

As noted previously, this report does not give substation configurations for load and generation buses. However, for any assumed configuration, the foregoing data on bus sections and circuit breaker outages could be used to model substation reliability.

No data on scheduled outages of transmission equipment is given. This does not imply that scheduled outages are felt to have negligible effect on reliability. Like partial outages of generating units, scheduled outages of transmission lines can have a major impact on reliability. However, very little published data on scheduled outages is available. Therefore, the task force decided to leave this as another parameter to be specified for a particular application. Hopefully this will encourage publication of typical scheduled outage data by various organizations.

There are several lines which are assumed to be on a common right of way or common tower for at least a part of their length. These pairs of lines are indicated in Figure 1 by circles around the line pair, and an associated letter identification. Table 12 gives the actual length of common right of way or common tower. For example, lines from buses 22-21 and 22-17 are 47 and 73 miles long respectively. Table 12 shows that 45 miles of this distance is on a common right of way.

Table 12
Circuits on Common Right of Way or Common Structure

Right-of Way Identification	From Bus	To Bus	Common ROW miles	Common Structure miles
A	22	21	45.0	
	22	17	45.0	
B	23	20		15.0
	23	20		15.0
C	21	18		18.0
	21	18		18.0
D	15	21	34.0	
	15	21	34.0	
E	13	11		33.0
	13	12		33.0
F	8	10		43.0
	8	9		43.0
G	20	19		27.5
	20	19		27.5

In addition to the exposure to outages shown in Table 11, the circuits on a common right of way or a common structure in Table 12 are exposed to "common mode" outages, in which a single event causes an outage of both lines. There is currently a great interest in data on the frequency of such common mode events. However, very little data of this type has been published. Therefore, as with scheduled outages, the task force elected not to publish arbitrary values of common mode outage rates, with the hope that users of the test system would publish data or assumptions used in particular studies.

Table 13
Impedance and Rating Data

From Bus	To Bus	Impedance P.U./100 MVA Base R	X	B	Rating (MVA) Normal	Short Term	Long Term	Equipment
1	2	.0026	.0139	.4611	175	200	193	138 kV cable
1	3	.0546	.2112	.0572	"	220	208	138 kV line
1	5	.0218	.0845	.0229	"	"	"	"
2	4	.0328	.1267	.0343	"	"	"	"
2	6	.0497	.1920	.0520	"	"	"	"
3	9	.0308	.1190	.0322	"	"	"	"
3	24	.0023	.0839		400	600	510	Transformer
4	9	.0268	.1037	.0281	175	220	208	138 kV line
5	10	.0228	.0883	.0239	"	"	"	"
6	10	.0139	.0605	2.459	"	200	193	138 kV cable
7	8	.0159	.0614	.0166	"	220	208	138 kV line
8	9	.0427	.1651	.0447	"	"	"	"
8	10	.0427	.1651	.0447	"	"	"	"
9	11	.0023	.0839		400	600	510	Transformer
9	12	.0023	.0839		400	"	"	"
10	11	.0023	.0839		400	"	"	"
10	12	.0023	.0839		400	"	"	"
11	13	.0061	.0476	.0999	500	625	600	230 kV line
11	14	.0054	.0418	.0879	"	"	"	"
12	13	.0061	.0476	.0999	"	"	"	"
12	23	.0124	.0966	.2030	"	"	"	"
13	23	.0111	.0865	.1818	"	"	"	"
14	16	.0050	.0389	.0818	"	"	"	"
15	16	.0022	.0173	.0364	"	"	"	"
15	21	.0063	.0490	.1030	"	"	"	"
15	21	.0063	.0490	.1030	"	"	"	"
15	24	.0067	.0519	.1091	"	"	"	"
16	17	.0033	.0259	.0545	"	"	"	"
16	19	.0030	.0231	.0485	"	"	"	"
17	18	.0018	.0144	.0303	"	"	"	"
17	22	.0135	.1053	.2212	"	"	"	"
18	21	.0033	.0259	.0545	"	"	"	"
18	21	.0033	.0259	.0545	"	"	"	"
19	20	.0051	.0396	.0833	"	"	"	"
19	20	.0051	.0396	.0833	"	"	"	"
20	23	.0028	.0216	.0455	"	"	"	"
20	23	.0028	.0216	.0455	"	"	"	"
21	22	.0087	.0678	.1424	"	"	"	"

Impedance and rating data for lines and transformers is given in Table 13. The "B" value in the impedance data is the total amount, not the value in one leg of the equivalent circuit. Three ratings are given; normal, short term, and long term. The normal rating indicates the daily peak loading capability of a circuit with due allowance for load cycles. The long-term rating means a circuit's capability to handle a 24 hour load cycle following a contingency. The short-term rating indicates the loading capability of a circuit following one or more system contingencies allowing for 15 minutes to provide corrective action. No attempt has been made to provide data on seasonal variation in line ratings. The data in Table 13 should be taken as the ratings at the time of annual system peak, which is week 51 (Table 1).

The data in the paper is sufficient to completely define a DC load flow for the test system. However, an AC load flow is not completely defined. Data on reactive impedances and loads are given, but complete specification of data for an AC load flow requires additional assumptions with regard to voltages at generator buses (regulated) and transformer tap information (tap ratio, fixed tap or LTC).

Reliability Test System Design Criteria

The predominant criteria in choice of the test system configuration was the desire to achieve a useful reference for testing and comparison of reliability evaluation methods. In light of this goal, the task force attempted to incorporate sufficient complexity and detail so that the test system would be representative of actual utility system applications. The test system was designed to have a lower reliability than is typically considered acceptable in utility planning. This was done to facilitate use of the test system in comparison of results from a wide variety of methods. In addition, the ability to evaluate alternatives for reliability can be considered. As experience is gained from study of the test system by various investigators, it may prove desirable to modify the system to be more useful as a means for evaluating and comparing reliability methods.

References

1. Synthetic Electric Utility Systems for Evaluating Advanced Technologies, EPRI Report EM-285, Final Report, Project TPS75-615, February 1977, Power Technologies Inc.

2. Working Group 01 of Study Committee 32 (System Planning and Operation), "Report on the Optimization of Power System Operation (CIGRE Exercise No. 2), "Electra, March, 1975 pp. 47-82.

3. IEEE Standard 346-1973 (Section 2), Terms for Reporting and Analyzing Outages of Electrical Transmission and Distribution Facilities and Interruptions to Customer Service.

Discussion

L.L. Garver (General Electric Company, Schenectady, NY): The test system will be a great help for illustrating power system measures and gaining new insights into their meaning.

One area where readers may wish to explore involves the loss-of-load probability quantity. An essential piece of information is the capacity outage table (1). This table is not easily calculated without the use of a digital computer program. Once the table is available, then maintenance scheduling ideas and new unit additions may be studied with a digital computer (2, 3). This publication will benefit from the inclusion of the capacity outage table.

REFERENCES

(1) R. Billinton, *Power System Reliability Evaluation,* New York: Gordon and Breach, 1970, pp. 97–102.

(2) L. L. Garver, "Adjusting Maintenance Schedules to Levelize Risk", *IEEE Transactions on Power Apparatus and Systems,* vol. PAS-91, pp. 2057–2063, September-October 1972.

(3) L. L. Garver, "Effective Load Carrying Capability of Generating Units", *IEEE Transactions on Power Apparatus and Systems,* vol. PAS-85, pp. 910–919, August 1966.

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Paul F. Albrecht on behalf of the **Test System Task Force:** We appreciate the comments by Dr. Garver, and we agree that a capacity outage table would be useful. A complete capacity outage table was prepared using the recursive equation given in reference (1) of Garver's discussion. The table was prepared without rounding unit capacities. Tables 1 and 2 give selected results from this "exact" (no roundoff) table. In the tables, x is the MW outage and P(x) is the probability of x or more MW on outage.

For the range 0-60 MW, Table 1 defines every change in the function P(x). For example, the minimum unit size in the test system is 12 MW. Hence, P(x) = 0.763604 for all positive values up to X = 12. Similarly, the table is constant from x = 12 to x = 20 since 20 MW is the second smallest unit size. The next change in P(x) is 24 MW (two 12 MW units out), and the next at 32 MW (20 + 12).

Beyond x = 60, Table 1 tabulates values of P(x) in increments of 20 MW. These values were extracted from the complete cumulative outage table. Therefore, the tabulated values of P(x) are exact. However, between successive values, P(x) is not constant (nor is the change linear with x).

Table 2 extends the range of Table 1 to 2450 MW, using an increment of 50 MW. The number in parenthesis in Table 2 is the negative exponent of 10 to be applied. For example, for

$$x = 1500,\ P(x) = 0.4043(10)^{-4}.$$

Tables 1 and 2 do not include any maintenance. All 32 units have been included in the capacity outage table. Further, the hydro units are included at full (100%) capacity (see Table 6 of paper). Therefore, Tables 1 and 2 are based on the full system capacity of 3405 MW.

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Table 1
Capacity Outage Table
0 - 1600 MW

x	P(x)	x	P(x)	x	P(x)
0	1.000000	420	0.186964	1020	0.003624
12	0.763604	440	0.151403	1040	0.003257
20	0.739482	460	0.137219	1060	0.002857
24	0.634418	480	0.126819	1080	0.002564
32	0.633433	500	0.122516	1100	0.002353
36	0.622712	520	0.108057	1120	0.002042
40	0.622692	540	0.101214	1140	0.001889
44	0.605182	560	0.084166	1160	0.001274
48	0.604744	580	0.075038	1180	0.000925
50	0.604744	600	0.062113	1200	0.000791
52	0.590417	620	0.054317	1220	0.000690
56	0.588630	640	0.050955	1240	0.000603
60	0.588621	660	0.047384	1260	0.000490
80	0.559930	680	0.044769	1280	0.000430
100	0.547601	700	0.042461	1300	0.000401
120	0.512059	720	0.040081	1320	0.000305
140	0.495694	740	0.038942	1340	0.000257
160	0.450812	760	0.030935	1360	0.000164
180	0.425072	780	0.026443	1380	0.000122
200	0.381328	800	0.024719	1400	0.000102
220	0.355990	820	0.018716	1420	0.000084
240	0.346093	840	0.015467	1440	0.000071
260	0.335747	860	0.013416	1460	0.000056
280	0.328185	880	0.012136	1480	0.000046
300	0.320654	900	0.011608	1500	0.000040
320	0.314581	920	0.009621	1520	0.000027
340	0.311752	940	0.008655	1540	0.000020
360	0.283619	960	0.006495	1560	0.000013
380	0.267902	980	0.005433	1580	0.000010
400	0.261873	1000	0.004341	1600	0.000008

Table 2
Capacity Outage Table
1500 - 2450 MW

x	P(x)	x	P(x)
1500	0.4044(4)	2000	0.7246(8)
1550	0.1490(4)	2050	0.2951(8)
1600	0.8064(5)	2100	0.8431(9)
1650	0.4076(5)	2150	0.3057(9)
1700	0.1583(5)	2200	0.9270(10)
1750	0.7216(6)	2250	0.2323(10)
1800	0.2912(6)	2300	0.7971(11)
1850	0.1529(6)	2350	0.1664(11)
1900	0.4692(7)	2400	0.4697(12)
1950	0.2151(7)	2450	0.1045(12)