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A RELIABILITY TEST SYSTEM FOR EDUCATIONAL PURPOSES - BASIC RESULTS

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ABSTRACT

This paper presents a set of basic reliability indices at the generation and composite generation and transmission levels for a small reliability test system. The data for this system are provided in Reference 1. The test system and the results presented in this paper have evolved from the reliability research and teaching programs conducted at the University of Saskatchewan. The indices presented in this paper are for fundamental reliability applications which should be covered in a power system reliability teaching program. The test system designated as the RBTS and the basic indices provide a valuable reference for faculty and students engaged in reliability teaching and research.

Keywords: Reliability test system, generating adequacy, composite system adequacy, operating reserve, reliability worth.

INTRODUCTION

The function of a modern power system is to satisfy the system load at a reasonable cost and with a reasonable assurance of continuity and quality. The recognition of ''reasonable assurance'' is the basis for a wide range of studies generally designated as reliability assessments. The term reliability has an extremely wide range of meaning [2]. In the power system context it can be divided into two basic aspects: system adequacy and system security [2]. Adequacy relates to the existence of sufficient facilities within the system to satisfy the consumer load demand or system operational constraints. Security relates to the ability of the system to respond to disturbances arising within that system. Most of the basic techniques available for quantitative reliability assessment are in the adequacy domain.

The basic techniques for reliability evaluation can be categorized in terms of the fundamental segments of a power system, which are generation, transmission, and distribution [3]. These functional zones can be considered to form a series of hierarchical zones or levels. Hierarchical level one (HLI) is concerned only with the generation facilities while hierarchical level two (HLII) includes both generation and transmission. Hierarchical level three (HLIII) includes all three functional zones. HLI studies are performed to determine the ability of the generation system to satisfy the overall demand. HLII studies indicate the ability of the composite generation and transmission system to satisfy the demand at the major load points. HLIII assessment examines the system ability to satisfy actual customer requirements. A detailed discussion of the hierarchical assessment approach is provided in Reference 3.

Reference 1 presents a relatively simple test system which has evolved from the research and graduate teaching program conducted at the University of Saskatchewan by Professor R. Billinton. The test system contains the basic information required to conduct fundamental reliability studies at HLI and HLII. The reliability test system, designated as the RBTS, provides a basic framework for introducing students to fundamental power system reliability evaluation. The system is sufficiently small that many applications can be conducted using hand calculators or relatively simple computer programs. This provides a valuable learning process for the student prior to developing or simply running more sophisticated computer programs for practical system studies.

This paper presents the results for a series of fundamental reliability studies using the RBTS. The theoretical concepts and methodologies involved are not presented in this paper. This material is covered in detail in Reference 4 which is used as the basic text in the power system reliability teaching program at the University of Saskatchewan.

HIERARCHICAL LEVEL ONE STUDIES

Adequacy Evaluation

The basic approach to generating capacity adequacy assessment is to develop a capacity model and to convolve this model with an appropriate load model to produce a risk index. The most fundamental capacity model for a generation system is a capacity outage probability table. Table I shows the basic capacity model for the RBTS obtained using a two state model for each generating unit. The table has been truncated at 10^{-7}. Table I also shows the basic risk indices of Loss of Load Expectation (LOLE) in days/year and hours/year and Loss of Energy Expectation (LOEE) for the RBTS at a system peak load of 185 MW. These values were obtained by using the 364 and 8736 individual daily peak and hourly load values respectively in the case of the LOLE indices and the 8736 hourly load values for the LOEE index. These values can be considered as the generic adequacy indices at HLI. No additional approximations or modification are required or used in the approach and these indices can be considered as reference values for comparison with indices developed using other techniques. An illustration of a basic approximation technique which can be extremely useful in large practical system studies is given in Table II. In this table, the capacity outage probability table has been rounded to 10 MW increments to reduce the number of steps and subsequent computing time. Table II also shows the LOLE and LOEE indices in this case.

Reference 4 provides a basic algorithm for capacity model building using two state and multi-state unit representations. Reference 1

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includes derated state data for the 40 MW thermal units in the RBTS. Tables III and IV show the basic capacity models with and without table rounding. The HLI adequacy indices are also shown in Tables III and IV.

Table I. Basic Capacity Model Two State Unit Representation

Capacity in (MW)	Capacity out (MW)	Individual Probability	Cumulative Probability
240.0	0.0	0.8128597	1.0000000
235.0	5.0	0.0164214	0.1871403
230.0	10.0	0.0166719	0.1707189
225.0	15.0	0.0003351	0.1540470
220.0	20.0	0.0703586	0.1537119
215.0	25.0	0.0014214	0.0833533
210.0	30.0	0.0014430	0.0819319
205.0	35.0	0.0000290	0.0804889
200.0	40.0	0.0692697	0.0804599
195.0	45.0	0.0013994	0.0111902
190.0	50.0	0.0014207	0.0097908
185.0	55.0	0.0000286	0.0083701
180.0	60.0	0.0058285	0.0083415
175.0	65.0	0.0001177	0.0025130
170.0	70.0	0.0001195	0.0023953
165.0	75.0	0.0000024	0.0022758
160.0	80.0	0.0020015	0.0022734
155.0	85.0	0.0000404	0.0002719
150.0	90.0	0.0000411	0.0002315
145.0	95.0	0.0000008	0.0001904
140.0	100.0	0.0001594	0.0001896
135.0	105.0	0.0000032	0.0000302
130.0	110.0	0.0000033	0.0000270
125.0	115.0	0.0000001	0.0000237
120.0	120.0	0.0000212	0.0000236
115.0	125.0	0.0000004	0.0000024
110.0	130.0	0.0000004	0.0000020
105.0	135.0	0.0000000	0.0000016
100.0	140.0	0.0000015	0.0000016
95.0	145.0	0.0000000	0.0000001
90.0	150.0	0.0000000	0.0000001
85.0	155.0	0.0000000	0.0000001
80.0	160.0	0.0000001	0.0000001

LOLE = 0.14695 days/year
LOLE = 1.09161 hours/year
LOEE = 9.83 MWh/year

Table II. Rounded Capacity Model

Capacity in (MW)	Capacity out (MW)	Individual Probability	Cumulative Probability
240.0	0.0	0.8210702	1.0000000
230.0	10.0	0.0250502	0.1789298
220.0	20.0	0.0712368	0.1538796
210.0	30.0	0.0021682	0.0826428
200.0	40.0	0.0699839	0.0804746
190.0	50.0	0.0021347	0.0104907
180.0	60.0	0.0059016	0.0083560
170.0	70.0	0.0001796	0.0024544
160.0	80.0	0.0020229	0.0022748
150.0	90.0	0.0000617	0.0002519
140.0	100.0	0.0001615	0.0001902
130.0	110.0	0.0000049	0.0000287
120.0	120.0	0.0000215	0.0000238
110.0	130.0	0.0000007	0.0000023
100.0	140.0	0.0000015	0.0000016
90.0	150.0	0.0000000	0.0000001
80.0	160.0	0.0000001	0.0000001

LOLE = 0.14732 days/year
LOLE = 1.09565 hours/year
LOEE = 9.83 MWh/year

A comparison of the adequacy indices in Table I and Table III/Table II and Table IV clearly shows the effect of using a derating adjusted forced outage rate as opposed to a multi-state generating unit representation.

Table III. Basic Capacity Model Derated State Representation Included

Capacity in (MW)	Capacity out (MW)	Individual Probability	Cumulative Probability
240.0	0.0	0.7961861	1.0000000
235.0	5.0	0.0160846	0.2038139
230.0	10.0	0.0163299	0.1877293
225.0	15.0	0.0003283	0.1713994
220.0	20.0	0.1020898	0.1710711
215.0	25.0	0.0020624	0.0689813
210.0	30.0	0.0020938	0.0669189
205.0	35.0	0.0000421	0.0648251
200.0	40.0	0.0549917	0.0647830
195.0	45.0	0.0011109	0.0097913
190.0	50.0	0.0011279	0.0086804
185.0	55.0	0.0000227	0.0075525
180.0	60.0	0.0058136	0.0075298
175.0	65.0	0.0001174	0.0017162
170.0	70.0	0.0001192	0.0015988
165.0	75.0	0.0000024	0.0014796
160.0	80.0	0.0012970	0.0014772
155.0	85.0	0.0000262	0.0001802
150.0	90.0	0.0000266	0.0001540
145.0	95.0	0.0000005	0.0001274
140.0	100.0	0.0001098	0.0001269
135.0	105.0	0.0000022	0.0000171
130.0	110.0	0.0000023	0.0000149
125.0	115.0	0.0000000	0.0000126
120.0	120.0	0.0000114	0.0000126
115.0	125.0	0.0000002	0.0000012
110.0	130.0	0.0000002	0.0000010
105.0	135.0	0.0000000	0.0000008
100.0	140.0	0.0000007	0.0000008
95.0	145.0	0.0000001	0.0000001

LOLE = 0.10038 days/year
LOLE = 0.72286 hours/year
LOEE = 6.34 MWh/year

Table IV. Rounded Capacity Model Derated State Representation Included

Capacity in (MW)	Capacity out (MW)	Individual Probability	Cumulative Probability
240.0	0.0	0.8042283	1.0000000
230.0	10.0	0.0245363	0.1957717
220.0	20.0	0.1032851	0.1712354
210.0	30.0	0.0031461	0.0679503
200.0	40.0	0.0555682	0.0648042
190.0	50.0	0.0016947	0.0092360
180.0	60.0	0.0058837	0.0075413
170.0	70.0	0.0001792	0.0016576
160.0	80.0	0.0013113	0.0014784
150.0	90.0	0.0000400	0.0001671
140.0	100.0	0.0001111	0.0001271
130.0	110.0	0.0000034	0.0000160
120.0	120.0	0.0000115	0.0000126
110.0	130.0	0.0000004	0.0000011
100.0	140.0	0.0000007	0.0000007

LOLE = 0.10071 days/year
LOLE = 0.72608 hours/year
LOEE = 6.38 MWh/year

Expected Unit Energy Production

The system LOLE and LOEE are independent of the unit loading order if there are no energy limited units in the system [4]. The load modification approach can be used to calculate the expected energy supplied by each unit and the system LOEE using the system load duration curve. Reference 1 gives a 100 point representation of the load duration curve.

Reference 1 also gives two loading orders for the generating units. Table V shows the individual unit expected energy production and the average system production cost for loading order #1 and the 100 point load model. Table VI shows similar information for loading order #2.

Table V. RBTS Unit Energy Production Loading Order #1

Capacity (MW)	Energy Cost ($/MW-hr)	Expected Energy Output (MW-hr)	Expected Energy Cost ($)
40.0	0.50	342435.13	171217
20.0	0.50	172088.66	86044
20.0	0.50	167559.50	83779
20.0	0.50	134934.88	67467
20.0	0.50	94142.83	47071
5.0	0.50	17077.93	8538
5.0	0.50	14534.61	7267
40.0	12.00	46982.64	563791
40.0	12.00	2980.10	35761
20.0	12.25	130.37	1597
10.0	12.50	18.02	225
		992884.67	1072757

Loss of Load Expectation = 1.09651 hrs/year
Expected Load Energy Required = 992894.44 MWh/year
Loss of Energy Expectation = 9.77 MWh/year

HLI adequacy can be improved by interconnecting the system to another power system. Each individual system within the interconnected configuration will require a lower generating reserve margin to maintain the risk level achieved prior to interconnection. This condition is brought about by the diversity in the occurrence of load conditions and capacity outages in the different member systems of an interconnected pool. The actual interconnection benefits depend on the installed capacity in each member system, the actual tie capacities, the forced outage rates of the tie lines, the load levels and the residual uncertainties [4] in each member system, and the type of agreement in existence among them.

Table VI. RBTS Unit Energy Production Loading Order #2

Capacity (MW)	Energy Cost ($/MW-hr)	Expected Energy Output (MW-hr)	Expected Energy Cost ($)
40.0	0.50	342435.13	171217
20.0	0.50	172088.66	86044
20.0	0.50	167559.50	83779
40.0	12.00	224981.30	2699775
40.0	12.00	77297.34	927568
20.0	12.25	6253.90	76610
10.0	12.50	1254.29	15678
20.0	0.50	854.75	427
20.0	0.50	141.25	70
5.0	0.50	11.56	5
5.0	0.50	6.99	3
		992884.67	4061176

Loss of Load Expectation = 1.09651 hrs/year
Expected Load Energy Required = 992894.44 MWh/year
Loss of Energy Expectation = 9.77 MWh/year

Reference 1 gives tie line data for interconnecting two or more RBTS. Consider two RBTS interconnected using a single tie line and that there is perfect load correlation between the two systems. It has also been assumed that one system will assist the other system up to the point of sharing in a load loss situation. The LOLE in each system is now 0.04270 hrs/yr compared to the value of 1.09161 hrs/yr on an isolated system basis. Table VII shows a range of LOLE value for selected system studies on two interconnected RBTS.

Table VII. Interconnected System Results

Tie Capacity (MW)	Tie Line FOR	LOLE hrs/yr	LOLE days/yr
0	0	1.09161	0.14695
30	0	0.04165	0.00625
30	0.001	0.04270	0.00639
30	0.003	0.04480	0.00667
10	0.001	0.37609	0.05518
20	0.001	0.11558	0.01737
40	0.001	0.01743	0.00295

Security Evaluation

Probabilistic techniques can be applied to evaluate the unit commitment and spinning reserve requirements in a power system [4]. The basic intent in using a probabilistic technique is to maintain the unit commitment risk equal to or less than a certain specified value throughout the day. The magnitude of spinning reserve to satisfy a certain unit commitment risk is very dependent on the time required for additional capacity to be placed in service. This delay is known as the system lead time. The required unit commitment basically depends on system load, generating unit failure rates, lead time, and the acceptable unit commitment risk level. A capacity model can be built in the form of a capacity outage probability table to examine the operating risk and to determine the required unit commitment. In the case of a spinning reserve study, the outage replacement rate (ORR) is used rather than the forced outage rate (FOR) parameter utilized in adequacy assessment [4]. The unit commitment risk and spinning reserve can be found from the capacity outage probability table given the forecast load. The capacity outage probability table for the RBTS, using the first 8 units of loading order #2, is shown in Table VIII. A lead time of 4 hrs is assumed. The table is truncated at a cumulative probability value less than 10^{-8}.

Table VIII. Capacity Outage Probability Table of the RBTS

Capacity In (MW)	Capacity Out (MW)	Cumulative Probability
210	0	1.00000000
200	10	0.01415992
190	20	0.01235600
180	30	0.00685540
170	40	0.00684533
160	50	0.00006532
150	60	0.00005291
140	70	0.00001513
130	80	0.00001507
120	90	0.00000011
110	100	0.00000009
100	110	0.00000001
90	120	0.00000001

The operating or unit commitment risk is the probability of just carrying or failing to carry the designated load. If the system load is 185 MW, then the corresponding unit commitment risk as shown in Table VIII is 0.00685540. The RBTS with its first 8 units from loading order #2 can carry a load of 160 MW when a risk level of 0.001 is selected as the acceptable unit commitment risk. If the specified unit commitment risk is 0.001, it can be seen from Table VIII that more than 8 units should be committed to satisfy a load of 185 MW. Table IX shows the spinning reserve and unit commitment risk for a load of 185 MW as the number of committed units are increased. It can be seen that 9 units should be committed to carry a load level of 185 MW at the specified risk of 0.001. The actual unit commitment risk in this case is 0.00007276 as shown in Table IX. The addition of the 10th unit, as shown in Table IX, does not change the unit commitment risk at a load of 185 MW.

Table IX. Spinning Reserve and Unit Commitment Risk

No.of Units Committed	Total Spinning Capacity (MW)	Spinning Reserve(MW)	Unit Commitment Risk
7	190	5	0.01307836
8	210	25	0.00685540
9	230	45	0.00007276
10	235	50	0.00007276

Reference 1 gives an optional model for the 2-40 MW thermal units which includes a single derated state. The unit commitment and corresponding spinning reserve considering the 2-40 MW thermal units with derating for a load level of 185 MW is shown in Table X.

Table X. Unit Commitment and Spinning Reserve

No.of Units Committed	Total Spinning Capacity(MW)	Spinning Reserve(MW)	Unit Commitment Risk
7	190	5	0.01307834
8	210	25	0.00504981
9	230	45	0.00005659
10	235	50	0.00005659

The number of units to be committed when recognizing unit derating is still 9 for a load of 185 MW and a specified risk of 0.001. The actual unit commitment risk with derating, however, is 0.00005659. The unit commitment risk for a similar generation level without recognizing derating is 0.00007276.

HIERARCHICAL LEVEL TWO STUDIES

The basic procedures for composite generation and transmission system or HLII adequacy evaluation are described in detail in Reference 4. It is laborious to perform HLII studies, even for small systems, using hand calculations particularly if the system requires an ac or dc load flow solution technique for contingency evaluation. The simplest form of solution technique is a network flow approach where a transmission element is assigned a designated carrying capability.

The results for a number of HLII adequacy studies on the RBTS are presented in this section. These studies and results can be divided into two groups:

1. Adequacy evaluation using the network flow(NF) method.
2. Adequacy evaluation using the ac load flow (ACLF) approach.

The number of contingencies considered using the NF and ACLF methods are given in Table XI.

In the case of generator outages, all outages involving four or less than four generating units have been considered. In the case of line outages, only those outages that involve three or less than three lines have been included. In the case of combined generator and line outages, situations involving up to two generating units and one line and one generating unit and two lines have been considered. Sixty three percent of total contingencies result in load curtailments in the system while two percent of all the contingencies results in voltage violations. Outage of lines 5 and 8 results in a split network situation. Outage of line 9 and all other more-off contingencies involving line 9 result in the isolation of bus 6. A more-off state at a contingency level is a state in which at least one more component is out of service in addition to those already out at that level, e.g. for 2nd level independent outages, states representing the outage of three or more than three components in addition to those states involving two components on outage are designated as more-off states.

Table XI. Contingencies Considered

Description	NF Method	ACLF
Number of generator contingencies considered	561	561
Number of line contingencies considered	129	129
Number of generator-line contingencies considered	990	990
Number of voltage violation contingencies	0	35
Number of MVAr limit violation contingencies	0	0
Number of no-convergence contingencies	0	22
Number of load curtailment contingencies	1168	1056
Number of firm load curtailment contingencies	457	637
Number of bus isolation contingencies	192	192
Number of split network contingencies	21	21

Network Flow Approach

The RBTS has been analyzed using the network flow method in which each element is given a maximum load carrying capability designated by the per unit current rating in Reference 1. Table XII shows the annualized bus indices using the network flow method. The maximum values of the bus indices are presented in Table XIII.

Table XII. Annualized Bus Indices Using the Network Flow Method

Bus	Failure Probability	Failure Frequency	Number of Load Curtailments Total	Number of Load Curtailments Isolated	Load Curtailed (MW) Total	Load Curtailed (MW) Isolated
2	0.0083367	3.6419752	3.64	0.00	4.66	0.00
3	0.0083833	3.7288585	3.73	0.00	19.55	0.00
4	0.0083833	3.7290108	3.73	0.00	9.20	0.00
5	0.0083846	3.7314045	3.73	0.00	4.65	0.00
6	0.0095198	4.8542213	4.85	1.13	27.34	22.51

Bus	Energy Curtailed (MWh) Total	Energy Curtailed (MWh) Isolated	Duration of Load Curtailment(Hrs) Total	Duration of Load Curtailment(Hrs) Isolated
2	89.00	0.00	73.03	0.00
3	371.48	0.00	73.44	0.00
4	174.82	0.00	73.44	0.00
5	87.61	0.00	73.44	0.00
6	289.01	199.24	83.39	9.96

The annualized system indices using the network flow method are given in Table XIV.

AC Load Flow Approach

Table XV summarizes the annualized bus indices for the system peak load of 185 MW. Load bus 3 is the least adequate bus in the system. This bus experiences a load curtailment whenever a 40 MW generating unit at bus 1 is under outage together with another generating unit (≥20 MW) in the system. Bus 5 has the lowest frequency of load curtailments which indicates that this bus is in difficulty only very rarely. Load curtailments at bus 6 are due to the isolation of this bus whenever line 9 is involved in an outage situation. The expected values of load and energy curtailed at each bus are also shown in Table XV. The amount of load curtailed at each bus due to a capacity deficiency can be decided in a number of ways. A load curtailment philosophy which interrupts load proportionately at system buses in the problem area is utilized in these studies. Buses considered in the problem area are those buses which are adjacent to the immediate location of a system problem. Outages of generating units at buses 1 and/or 2, therefore, curtail load at buses 2, 3 and 4. Buses 5 and 6 are not generally affected by generating unit outages. The last column of Table XV gives the number of voltage violations before and after reactive compensation is provided. The system buses generally experience voltage problems due to transmission line outages. The voltage problem is completely alleviated after providing reactive compensation.

Table XIII. Maximum Values of Bus Indices Using the Network Flow Method

Bus	Maximum Value	Probability	Contingency Frequency	Description Components out
		Maximum Load Curtailed (MW)		
2	9.19	0.0000002	0.0001743	Gen 1, 2, 7 & 8 out
3	48.38	0.0000000	0.0000355	Lines 1, 2 & 6 out
4	22.77	0.0000000	0.0000355	Lines 1,2 & 6 out
5	20.00	0.0000000	0.0000643	Gen 1, Lines 5 & 8 out
6	20.00	0.0009047	0.8456631	Lines 9 out
		Maximum Energy Curtailed (MWh)		
2	110.03	0.0000002	0.0001743	Gen 1, 2, 7 & 11 out
3	467.63	0.0000002	0.0001743	Gen 1, 2, 7 & 8 out
4	220.06	0.0000002	0.0001743	Gen 1, 2, 7 & 11 out
5	110.03	0.0000002	0.0001743	Gen 1, 2, 7 & 11 out
6	187.42	0.0009047	0.8456631	Lines 9 out
		Maximum Duration of Load Curtailment (Hrs.)		
2	24.40	0.0002448	0.0878699	Gen 7 & 8 out
3	24.40	0.0002448	0.0878699	Gen 7 & 8 out
4	24.40	0.0002448	0.0878699	Gen 7 & 8 out
5	24.40	0.0002448	0.0878699	Gen 7 & 8 out
6	24.40	0.0002448	0.0878699	Gen 7 & 8 out

Table XIV. Annualized System Indices Using the Network Flow Method

Probability of all components in service = 0.793555
Sum of the probabilities of all contingencies = 0.206418
Bulk Power Supply Disturbances = 5.38842

Basic Indices

Bulk Power Interruption Index = 0.35354 MW/MW-Yr
Bulk Power Energy Curtailment Index = 5.46985 MWh/MW-Yr
Bulk Power Supply Average MW Curtailment Index = 12.13801 MW/Dist.
Modified Bulk Power Energy Curtailment Index = 0.00062441
Severity Index = 328.191 System-Min.

Average Indices

Number of Load Curtailments/Load Point/Year = 3.93709
Number of Voltage Violations/Load Point/Year:
before compensation = 0.00000
after compensation = 0.00000
Load Curtailed/Load Point/Year = 13.08093 MW
Energy Curtailed/Load Point/Year = 202.38437 MWh
Hrs of Load Curtailment/Load Point/Year = 75.34928 Hrs

Table XV. Annualized Bus Indices Using the AC Load Flow Method

Bus	Failure Probability	Failure Frequency	Number of Load Curtailments Total	Number of Load Curtailments Isolated	Load Curtailed (MW) Total	Load Curtailed (MW) Isolated
2	0.0062284	2.6840122	2.68	0.00	6.03	0.00
3	0.0087344	4.2465763	4.25	0.00	47.46	0.00
4	0.0063303	2.8416128	2.84	0.00	13.91	0.00
5	0.0002065	0.2929301	0.29	0.00	0.44	0.00
6	0.0011610	1.1587838	1.15	1.13	22.60	22.50

Bus	Energy Curtailed (MWh) Total	Energy Curtailed (MWh) Isolated	Duration of Load Curtailment(Hrs) Total	Duration of Load Curtailment(Hrs) Isolated	Voltage Violations (occ) before compensation	Voltage Violations (occ) after compensation
2	121.93	0.00	54.56	0.00	0.00	0.00
3	824.50	0.00	76.51	0.00	0.01	0.00
4	264.67	0.00	55.45	0.00	0.00	0.00
5	2.76	0.00	1.78	0.00	0.01	0.00
6	199.74	199.21	10.14	9.96	0.01	0.00

The expected maximum indices at each load bus are given in Table XVI. As seen from the table, each bus experiences total load curtailment under certain transmission line outages. It is interesting to note that these line outages may not cause maximum energy curtailment at the corresponding bus(es). This is also true for the maximum duration of load curtailment index. The probability and frequency of each outage contingency which causes maximum values are also given in Table XVI.

Table XVI. Maximum Values of Bus Indices Using the AC Load Flow Method

Bus	Maximum Value	Probability	Contingency Frequency	Description Components out
		Maximum Load Curtailed (MW)		
2	20.00	0.0000000	0.0000925	Gen 7, Lines 1 & 6 out
3	85.00	0.0000000	0.0001181	Lines 1, 2 & 7 out
4	40.00	0.0000001	0.0001445	Gen 1, Lines 1 & 6 out
5	20.00	0.0000000	0.0000643	Gen 1, Lines 5 & 8 out
6	20.00	0.0009047	0.8456631	Lines 9 out
		Maximum Energy Curtailed (MWh)		
2	90.08	0.0005051	0.1964600	Gen 1 & 7 out
3	712.64	0.0000197	0.0122581	Gen 1, 2 & 4 out
4	520.38	0.0000001	0.0000376	Gen 7, 8, 9 & 11 out
5	96.74	0.0000010	0.0018677	Lines 5 & 8 out
6	187.42	0.0009047	0.8456631	Lines 9 out
		Maximum Duration of Load Curtailment (Hrs.)		
2	24.40	0.0002448	0.0878699	Gen 7 & 8 out
3	22.52	0.0005051	0.1964600	Gen 1, & 7 out
4	24.40	0.0002448	0.0878699	Gen 7 & 8 out
5	13.04	0.0000001	0.0000376	Gen 7, 8, 9, & 11 out
6	9.37	0.0009047	0.8456631	Lines 9 out

The annualized system indices are shown in Table XVII. The bulk power supply disturbance (BPSD) index is 5.75 which indicates that the system experiences load curtailment this many times in a year. The bulk power interruption index (BPII) value of 0.49 indicates that the total system load curtailed in a year is equivalent to 0.49 times the peak load of the system. Similarly, the bulk power energy curtailment index (BPECI) of 7.64 signifies that the total energy not supplied per year is equivalent to a total system shut down under peak load conditions for a period of 7.64 hours. The severity index is, therefore, 458.5 system minutes. The modified bulk power energy curtailment index (MBPECI) is 0.00087. This parameter indicates that the system is incapable of supplying 0.087% of the annual energy requirements of the total system.

Table XVII. Annualized System Indices Using the AC Load Flow Method

Probability of all components in service = 0.793555
Sum of the probabilities of all contingencies = 0.206418
Bulk Power Supply Disturbances = 5.75210

Basic Indices

Bulk Power Interruption Index = 0.48886 MW/MW-Yr
Bulk Power Energy Curtailment Index = 7.64115 MWh/MW-Yr
Bulk Power Supply Average MW Curtailment Index = 15.72272 MW/Dist.
Modified Bulk Power Energy Curtailment Index = 0.00087228
Severity Index = 458.469 System-Min.

Average Indices

Number of Load Curtailments/Load Point/Year = 2.24241
Number of Voltage Violations/Load Point/Year:
before compensation = 0.00366
after compensation = 0.00000
Load Curtailed/Load Point/Year = 18.08772 MW
Energy Curtailed/Load Point/Year = 282.72272 MWh
Hrs of Load Curtailment/Load Point/Year = 39.69029 Hrs

Annual Indices

Reference 1 shows an eight step approximation of the annual load duration curve which can be used to determine annual indices for the RBTS. The load increments at each bus and for the system are in 10% steps. Tables XVIII and XIX present the annual bus and system indices using the ac load flow method.

Common Cause Outages

The effect of considering common cause outages on the transmission facilities are shown in Tables XX and XXI. The basic data is given in Table XI in Reference 1.

Table XX. Annualized Bus Indices Including Common Cause Data Using the AC Load Flow Method

Bus	Failure Probability	Failure Frequency	Number of Load Curtailments Total	Number of Load Curtailments Isolated	Load Curtailed (MW) Total	Load Curtailed (MW) Isolated
2	0.0066614	2.9555395	2.96	0.00	8.39	0.00
3	0.0112562	5.9664044	5.80	0.00	97.69	0.00
4	0.0073310	3.5523348	3.55	0.00	33.43	0.00
5	0.0012221	1.0165927	0.55	0.00	2.80	0.00
6	0.0030161	2.4619596	2.10	1.31	40.10	26.19

Bus	Energy Curtailed (MWh) Total	Energy Curtailed (MWh) Isolated	Duration of Load Curtailment(Hrs) Total	Duration of Load Curtailment(Hrs) Isolated	Voltage Violations before compensation	Voltage Violations after compensation
2	155.18	0.00	58.35	0.00	0.00	0.00
3	1447.15	0.00	96.29	0.00	0.46	0.00
4	504.83	0.00	64.22	0.00	0.17	0.00
5	28.71	0.00	4.41	0.00	0.53	0.00
6	421.93	246.64	22.16	12.33	0.36	0.00

Reliability Worth

Reference 1 presents data on the perceived costs of power supply interruption to the major load classes. It also provides data on customer load and energy requirements and presents an overall system customer damage function. By far the broadest application of a customer damage function is its use to relate the composite customer losses to the socioeconomic worth of electric service reliability for an entire utility

Table XVIII. Annual Bus Indices Using the AC Load Flow Method

Bus	Failure Probab-ility	Failure Frequency	No. of Load Curts	Load Curtailed (MW)	Energy Curtailed (MWh)	Duration of Load Curts. (Hrs)	Voltage Violations before compensation
2	0.0003571	0.1673414	0.1669	0.21	3.6345	3.1285	0.0000
3	0.0005460	0.2724980	0.2687	1.81	29.4807	4.7830	0.0070
4	0.0003635	0.1776051	0.1757	0.49	8.1535	3.1841	0.0069
5	0.0000119	0.0180584	0.0116	0.04	0.2263	0.1042	0.0070
6	0.0011414	1.1327804	1.1302	14.88	131.5269	9.9988	0.0070

Table XIX. Annual System Indices Using the AC Load Flow Method

Bulk Power Supply Disturbances = 1.40216

Basic Indices

Bulk Power Interruption Index = 0.09422 MW/MW-Yr
Bulk Power Energy Curtailment Index = 0.93525 MWh/MW-Yr
Bulk Power Supply Average MW Curtailment Index = 12.43088 MW/Dist.
Modified Bulk Power Energy Curtailment Index = 0.00010676
Severity Index = 56.115 System-Min.

Average Indices

Number of Load Curtailments/Load Point/Year = 0.35060
Number of Voltage Violations/Load Point/Year:
before compensation = 0.0056
after compensation = 0.00000
Load Curtailed/Load Point/Year = 3.48602 MW
Energy Curtailed/Load Point/Year = 34.60435 MWh
Hrs of Load Curtailment/Load Point/Year = 4.23974 Hrs

Table XXI. Annualized System Indices Including Common-Cause Data Using the AC Load Flow Method

Probability of all components in service = 0.792626
Sum of the probabilities of all contingencies = 0.209608
Bulk Power Supply Disturbances = 8.04353

Basic Indices

Bulk Power Interruption Index = 0.98599 MW/MW-Yr
Bulk Power Energy Curtailment Index = 13.82593 MWh/MW-Yr
Bulk Power Supply Average MW Curtailment Index = 22.67769 MW/Dist.
Modified Bulk Power Energy Curtailment Index = 0.00157830
Severity Index = 829.556 System-Min.

Average Indices

Number of Load Curtailments/Load Point/Year = 2.99047
Number of Voltage Violations/Load Point/Year:
before compensation = 0.30353
after compensation = 0.00000
Load Curtailed/Load Point/Year = 36.48175 MW
Energy Curtailed/Load Point/Year = 511.55951 MWh
Hrs. of Load Curtailment/Load Point/Year = 49.08767 Hrs.

service area. In order to assess the costs of customer losses, it is necessary to estimate the reliability indices for the system in a form that can be utilized to derive a total customers' interruption cost. The traditional LOLE index is not satisfactory for this purpose. In order to calculate customer losses, it is also necessary to know the severity of failures. The information can be estimated by a Frequency and Duration (F&D) technique [4] which can compute the average frequency, duration, and magnitude of interruptions. The product of these three quantities is the LOEE of the load loss event. The LOEE is a relatively simple factor that is closely related to customer losses and provides a useful indicator of system adequacy. A customer interruption monetary cost estimate can be obtained by multiplying the system LOEE by a suitable monetary factor. This factor is designated as the Interrupted Energy Assessment Rate (IEAR) [3] and it is expressed in $/KWh. The procedure for obtaining a system IEAR is described in detail in Reference 3.

The basic models required in the estimation of the IEAR are as follows:

1. Generation Model: The generating units are characterized by their capacity, forced outage rates, failure rates and repair rates. These data are given in Reference 1.
2. Load Model: The exact-state type of load model is used in this study. This model represents the actual system load cycle by approximating it by a sequence of discrete load levels [4].
3. Cost Model: This is represented either by the composite customer damage function or by the sector costs of interruption with their distribution of energy and peak demand for the service area. These data are given in Reference 1.

Table XXII shows a simple exact state load model for the RBTS derived from the original load data.

Table XXII. Exact-state Load Model for the RBTS

Peak Load Level (MW)	No. of Occurrences (days)
185.00	12.0
167.55	82.0
149.35	107.0
131.45	116.0
109.63	47.0

Exposure Factor = 0.5 [4]
Low Load Level = 101.25

The IEAR in the RBTS is $3.60/KWh. This value can be used in conjunction with the basic LOEE index to determine an optimum generation reserve margin [3].

CONCLUSION

This paper has presented a set of basic reliability indices for the RBTS described in Reference 1. The test system is small and is intended for use in a graduate teaching and research environment. The results presented in this paper can be used to provide a datum against which trial solutions, approximate methods, and digital computer program results can be compared. This paper does not illustrate results from all possible studies which can be conducted using the RBTS presented in Reference 1. It does, however, provide results for some of the fundamental applications that should be covered in a basic power system reliability teaching program.

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