Paper accepted for presentation at 2009 IEEE Bucharest Power Tech Conference, June 28th - July 2nd, Bucharest, Romania

Components' Impact on Critical Transfer Section for Risk Based Transmission System Planning

Johan Setréus, *Graduate Student Member, IEEE,* Stefan Arnborg, *Member, IEEE*
Roland Eriksson, *Senior Member, IEEE* and Lina Bertling, *Senior Member, IEEE,*

***Abstract*—In the planning of the electrical transmission system it is of greatest concern to quantify the security margin for unwanted conditions in the system. This paper proposes an approach based on quantifying the risk of insufficient transmission capacity in bottlenecks in the system. Stresses in these critical transfer sections (CTS) provide a potential risk to corrective actions, or worst, load curtailments. The proposed method provides a general screening of component outages in order to find potential risk events for the CTS. Furthermore, the severity of each risk event is quantified based on the likelihood of the event and the consequence on the section's transmission capacity. The components' contribution to the risk of insufficient capacity in the CTS is then based on these risk events' severity. The method investigates several forecasted load levels during the year and consequently gives an input to a scheme for a risk based transmission system planning. The method is demonstrated on the reliability test system RBTS.**

***Index Terms*—Power transmission reliability, power system security, reliability modeling, risk analysis, power system planning.**

I. Introduction

RELIABILITY security assessments are of great concern for the transmission system operator. The operator and planner need simple and intuitive criteria to be able to make a judgement on the present or future security margin in the system. A common approach is to define and supervise critical transfer sections (CTS) in well known bottlenecks of the system. The maximum allowed power for each CTS is then set in accordance to accommodate the loss of any single major component, defined in a contingency list. The component outage with the largest consequence in the list, at the given system conditions, sets the CTS limit. However, the contingency list normally only includes single component outages and there is a grade of uncertainty if the list really includes the actual major component outages at different load conditions. With a limited number of assessed contingencies the worst outage may be missed. Furthermore, the evaluation takes no concern of the likelihood of the outage events and non-optimal decisions may therefore be the result in the planning and expansion process.

This work was supported by the Swedish Centre of Excellence in Electric Power Engineering (EKC2). J. Setréus, S. Arnborg, R. Eriksson and L. Bertling is with the School of Electrical Engineering, Royal Institute of Technology, KTH, Stockholm, Sweden. S. Arnborg is also with Svenska Kraftnät, i.e. the Swedish national grid company, and L. Bertling with Chalmers Technical University and Department of Energy and Environment, and Division of Electric Power Engineering. E-mail: johan.setreus@ee.kth.se, stefan.arnborg@ee.kth.se, roland.eriksson@ee.kth.se and lina.bertling@chalmers.se

Relatively few methods have been published that quantifies the power system security by considering the likelihood of component outages and the consequences to the system. One is the *well-being analysis* framework, where the deterministic N-1 security criterion is combined with probabilistic concepts in order to quantify the *degree of success* in the operating states of the transmission system [1], [2]. The measured consequence is here the amount of load shed necessary to keep the system stable or to avoid system violations such as line overloads. The results of well-being analysis are quite intuitive; e.g. how frequently the system will experience a violation to the N-1 criterion. The method is however dependent on adequate models for load shedding and system restoration after outage events; two properties that are complex to model correctly. In [3] the outage events' consequences instead are quantified in terms of thermal component overloads directly after the event. A high overloaded component gives a high estimated value of the monetary risk. The total component overload risk for a branch (e.g. a line or a transformer) is evaluated for each hour, given the included outage events probabilities, a load forecast, and the estimate of the overloads monetary risk. Given this, the annual component risk or the total system risk for each hour can be determined.

This paper proposes an approach that is similar to the method presented in [3]. Instead of evaluating separate branches, the risk of insufficient transmission capacity in the system's CTSs is quantified. Our hypothesis is that, if the assessed CTSs are the bottlenecks in the system, the condition of these transfer sections indicate the condition of the system transmission capability at different load levels. A stressed CTS implies a small security margin in the system which in its turn implies a higher risk for load curtailments for the customers. The method gives a systematic analysis of the consequences of outage events impact on a CTS capability to transfer active power for a number of load levels. The outage events include single- or multiple component outages of technical nature.

II. Transmission System Reliability

Power system reliability is often divided by the two functional aspects of system *adequacy* and *security*. Adequacy is considered to be the existence of sufficient facilities within a power system to satisfy the customer demand. System security, which is considered in this paper, is the ability of a power system to respond to disturbances arising within that system [4]. A power transmission system is a complex technical structure, consisting of a large number of interconnected subsystems and components which interact and influence on the overall system reliability. One definition of reliability is the ability of a component or system to perform required functions under stated conditions for a stated period of time [5]. The required function is here to supply the aggregate electric power and energy requirements of the customer, both generation and end users (load points), at all times.

Reliability assessments of the transmission system are often included in the decision making of e.g. new investments, maintenance and operation of the system. These assessments can be evaluated with a deterministic or probabilistic criterion, each with its own advantages. The key advantages for the probabilistic approach are the ability to quantify the stochastic nature of the system and to, ideally, include all combinations of component outages in the model. It is, however, far more complex to model, evaluate and maintain than the often more intuitive, simple implemented and easy assessed deterministic criteria.

The deterministic N-1 criterion has traditionally provided a security level for the transmission system in the design, planning and operation of the system. This criterion is a rule according to which the system must be able to withstand the loss of any single component [6]. The fulfilment of the N-1 criterion is normally checked for a list of major outages (e.g. loss of largest production unit or line) in a contingency security analysis, which can include both steady-state (static) and transient (dynamic) analysis. In both real-time operation and planning of the transmission system, it is common to only check the fulfilment of the N-1 criterion in a number of CTSs. A CTS is normally defined as a geographical cut-line across certain lines, where the present transfer on the CTS is the sum of all included lines active power flow. The transfer limits in these sections are adjusted regularly and are set to fulfil the N-1 criterion given thermal and stability constraints from the contingency analysis. The CTSs' active power margins are then evaluated continuously to give one measure of the present system security level.

The contingency list normally consists of single component outages based on expert judgements and system model analysis. Two weaknesses of the N-1 criterion are firstly, the lack of evaluation of multiple component outages and secondly, the absent of any estimate of the likelihood of the outage. These weaknesses can lead to a misjudgement of the true critical outages. A single component outage with large consequences, but with a very low probability of occurrence may be considered more important than a multiple component outage with the same consequences but with higher probability. One other weakness with the N-1 criterion in system planning is that the contingency analysis normally is performed in a worst case scenario at a system peak load level. The expected probability for this load situation may be very small and this may therefore lead to a misjudgement of the, most time of the year, actual risk outage events. It can be noted that a number of historical blackouts has occurred during a non-peak load situation, e.g. in Sweden 23rd September 2003 [7] and Europe 4th November 2006 [8].

III. Proposed Method

The proposed method quantifies and ranks the outage events impact on a CTS at different load levels. The outage events consequence on the system's load points are not considered here. Instead the condition of the system's transmission capacity is studied by the assessment of one or several CTSs. The result is a list of outage events with the highest risk of overloading a defined CTS for each assessed load level. These results are then used to determine how each examined component in the system contributes to the risk of overloading the CTS at different load levels.

A. Method description

Preparation of system model

1) The transmission system model is defined at component level. Each line, circuit breaker, disconnector, etc. is represented in the model. Impedances for the transmission lines, together with generator and load bus parameters are set in order to perform ordinary load flow analysis.
2) A CTS is defined with a maximum power transfer limit. This consists of e.g. two important lines in the system with the two lines' thermal limits in MW. However, other limits than thermal can be used and the CTS can be arbitrarily defined.
3) A load level in p.u. of the system peak load is set.
4) The expected failure rate (λ_{Comp}) and expected restoration time (r_{Comp}) are set in those components which impact on the CTS is to be studied. Maintenance outage rate and maintenance time is also set as a second failure mode.

System analysis

5) A list with single and multiple component outage events is constructed. The expected outage rate (λ_i) and expected restoration time (r_i) for each event is determined by the involved components' reliability data. The component outages in each event are assumed to be independent.
6) Each outage event's impact on the studied CTS active power transfer is evaluated with a load flow analysis. Outage events that result in an overload of the section are referred to as *risk-outages*. Outage events that result in a 0 MW transfer capability of the section are referred to as *total-outages*.
7) A total screening of the outage events' impact on the CTS is visualized in a diagram in order to evaluate potential risk-outages. The diagram gives an overview of each outage event's expected outage rate versus its resulting relative loading on the CTS after the event. If single component outages are present as risk-outages this implies that the N-1 criterion is not fulfilled for the CTS before the event, and thereby also the system for the studied load level.
8) The severity of each risk-outage on the CTS is then quantified given the events' expected outage and restoration rate and resulting CTS loading. The proposed risk index, I_i^{Risk}, is defined in (1) below.

Result evaluation

9) The risk-index I_i^{Risk} provides a ranking of the severity of each risk-outage, based on the overload of the CTS and the likelihood for this event to occur.
10) The risk-index I_i^{Risk} is not defined for total-outages. These have to be treated separately and are ranked with respect to their expected frequency of outage.
11) As one final assessment the list of risk-outages should be examined manually in order to identify if any components dependency is present in the events. If this is the case, an extra risk factor must be added to the risk given by the risk index defined in (1).
12) Outage events that are known to have other constraints on the CTS transfer limit than thermal, such as voltage or angle stability, could be assessed more in detail. This is because the thermal limit normally only provide the upper limit of the section's maximum transfer capability.
13) By adding the I_i^{Risk} for each risk outages' involved components, a cumulative risk is given per component in the system. This gives a measure of the components contribution to the risk of overloading the section. The components' associated risk, referred to I_{Comp}^{Risk}, is then sorted in order to determine which components that has the highest impact on the CTS capability to transfer power for the studied load level.
14) Step 3 to 13 is repeated for each load level to be studied in the system.

B. Index for risk outages, I_i^{Risk}

The risk index I_i^{Risk} in (1) is defined to quantify the likelihood and consequence of outage events having severe impact on the CTS's capability to transfer active power. The index is only defined for risk outages e.g. outages which result in an overload on the studied CTS. The first part in (1) describes how likely the outage is to occur and for how long it is expected to last. The second part quantifies the severeness of the risk outage's overload of the section. This is the relative loading of the section after the outage event and this part increase in quadrate with the overload. The quadratic property is justified by the fact that the heating of a conductor is proportional to the current squared.

$$I_i^{Risk} = \frac{\lambda_i r_i}{8760} \times (\frac{P_{after\_i}}{P_{limit\_after\_i}})^2 \tag{1}$$

where:
λ_i = expected frequency for outage event i [1/yr],
r_i = expected restoration time for outage event i [h],
8760 = hours per year,
P_{after_i}= active power transfer in CTS after outage event i,
$P_{limit\_after\_i}$ = active power transfer limit in CTS after outage event i.

IV. Reliability test system RBTS

A. Brief description

The Roy Billinton test system (RBTS) is a model for reliability studies at the transmission level. Table I gives a brief summary of the system properties. The system data is defined in [9] and results with system and load point reliability indices are presented in [10]. In five of RBTS six buses (Bus 2-Bus 6) load points are present and for two of these (Bus 2 and Bus 4) the underlying distribution system is defined in detail in [11]. In this paper only the transmission system of RBTS is studied, with the distribution systems represented as single load points (LP).

TABLE I
RBTS summary of system data [9]

Number of buses	6
Number of generators	11
Number of load points	5
Number of transmission lines	9
Number of generation buses	2
Installed generation [MW]	240
System peak load [MW]	185
AC nominal voltage [kV]	230

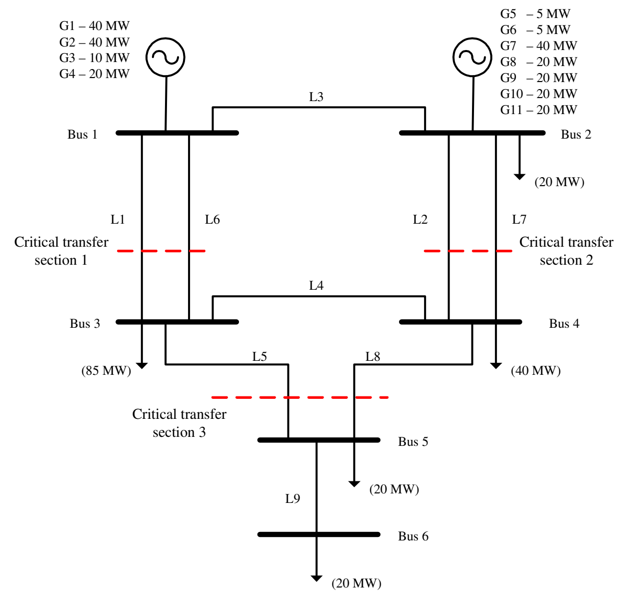

Fig. 1. A simplified single line diagram of RBTS, referred to as RBTS(1).

RBTS has in this paper been modelled in one basic and one extended version, referred to as RBTS(1) and RBTS(2), shown in Fig. 1 and 2, respectively. Three CTSs have in this paper been specified for three line pairs, as seen in the figures.

The system frequency is not specified in [9]; in this paper it is assumed to be 60 Hz. The π-model is assumed for the transmission lines. The electrical and reliability data for the components is assumed to be ideal if nothing else is specified.

B. Electrical data

The system has two generator (PV) buses and four load (PQ) buses. The voltages at the PV buses (Bus 1 and Bus 2) are controlled to 1.05 p.u. The voltage limits in the system are between 0.97 p.u. and 1.05 p.u. [9]. Table II shows the electrical data and lengths of the nine lines in the system.

Table III shows the load data for the LP:s at a system peak load. The load variation in RBTS (i.e. in p.u. of the peak load) is specified as the same as in IEEE-RTS [12]. The load

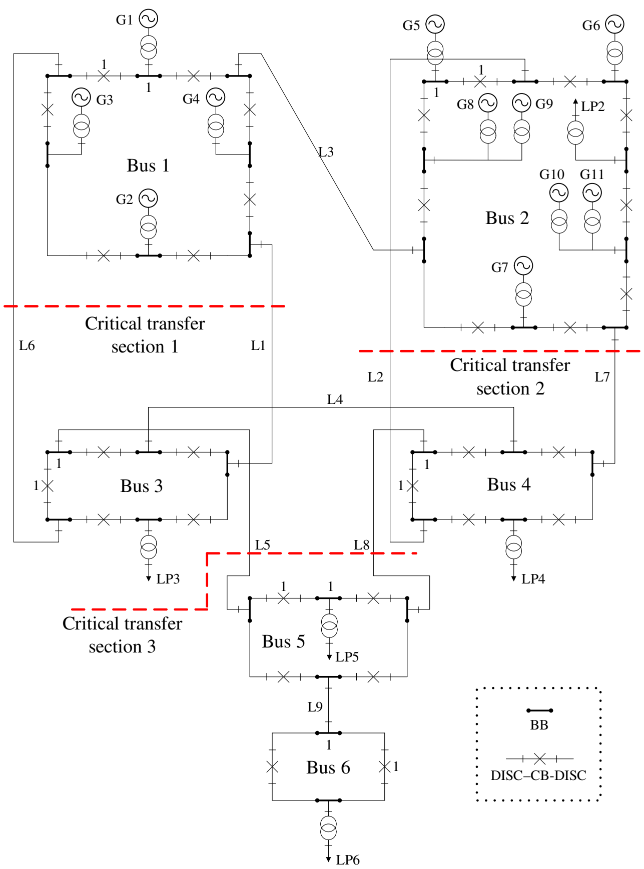

Fig. 2. Extended single line diagram of RBTS, referred to as RBTS(2), with the buses' substation configuration.

TABLE II
RBTS TRANSMISSION LINE DATA [9]

Line	From Bus	To Bus	Length (km)	Impedance (p.u.) R	X	Susceptance B/2 (p.u.)
L1	1	3	75	0.0342	0.18	0.0106
L2	2	4	250	0.114	0.6	0.0352
L3	2	1	200	0.0912	0.48	0.0282
L4	4	3	50	0.0228	0.12	0.0071
L5	3	5	50	0.0228	0.12	0.0071
L6	1	3	75	0.0342	0.18	0.0106
L7	2	4	250	0.114	0.6	0.0352
L8	4	5	50	0.0228	0.12	0.0071
L9	5	6	50	0.0228	0.12	0.0071

$S_{base} = 100MVA$, $U_{base} = 230kV$
Max current capacity for lines:
L1 and L6 $\longrightarrow$ I_{max} = 0.85 p.u., other line $\longrightarrow$ I_{max} = 0.71 p.u.

in each LP is assumed to consist of two categories, one firm load and one curtailable load. The latter part is set to 20% of each LP's load in RBTS. No load shedding policy, in case of severe outage events, has been specified in [9]. In this paper the priority order policy, defined for RBTS in [13], is implemented.

The ratings for the eleven generators in RBTS are given in Table IV. Generator G1 (in Bus 1) is set as the slack generator in this paper. G7 (in Bus 2) act as slack if Bus 1 is isolated. The scheduled generation in Bus 2 during peak load, given an intact system situation, is 120 MW.

TABLE III
LOAD DATA FOR THE FIVE LOAD POINTS IN RBTS [9]

Load point	Active load (peak) [MW]	Reactive load [Mvar]	Priority order[1][13]
LP2	20.0	0	1
LP3	85.0	0	5
LP4	40.0	0	3
LP5	20.0	0	2
LP6	20.0	0	4
Total	185.0	0	-

[1] LP3 is curtailed first with up to 20% of its load. After this, if necessary, the LP:s is curtailed with up to 20%, following the priority list order.

TABLE IV
RATINGS FOR THE ELEVEN GENERATORS IN RBTS [9]

Generator	Location	Rating [MW]	Capability [Mvar] Min	Max	Type
G1,G2	Bus 1	40	-15	17	Thermal
G3	Bus 1	10	0	7	Thermal
G4	Bus 1	20	-7	12	Thermal
G5,G6	Bus 2	5	0	5	Hydro
G7	Bus 2	40	-15	17	Hydro
G8-G11	Bus 2	20	-7	12	Hydro

TABLE V
RBTS COMPONENT RELIABILITY DATA [9]

Transmission Line (L)	
Permanent outage rate [f/yr,km]	0.02
Average outage duration [h]	10
Circuit Breaker (CB)	
Active failure rate [f/yr]	0.0066
Average outage duration [h]	72
Maintenance outage rate [f/yr]	0.2
Maintenance time [h]	108
Busbar (BB)	
Failure rate [f/yr]	0.22
Average outage duration [h]	10
Station Transformer (TR)	
Failure rate [f/yr]	0.02
Average outage duration [h]	768
Maintenance outage rate [f/yr]	0.2
Maintenance time [h]	72

C. Reliability data

Table V shows the component reliability data for; the lines, circuit breakers (CB), busbars (BB) and transformers (TR) in RBTS. It can be noted that the reliability of the components are relatively low compared to statistics for existing systems.

D. Specification of RBTS(1)

Fig. 1 shows the single line diagram of RBTS(1). This version of RBTS has a single busbar as substation configuration. All outgoing feeders from the BBs include a perfect CB, with a disconnector (DISC) at each side.

RBTS(1) only includes reliability data for the nine transmission lines L1-L9.

E. Specification of RBTS(2)

Fig. 2 shows the single line diagram of RBTS(2). In this extended version of RBTS, the substation configuration for

TABLE VI
THE ADDITIONAL NUMBER OF COMPONENTS IN RBTS(2) [9]

Number of busbars (BB)	32
Number of circuit breakers (CB)	32
Number of disconnectors (DISC)	51
Number of transformers (TR)	14

TABLE VII
LOAD FLOW RESULTS FOR AN INTACT RBTS AT THE PEAK LOAD 185 MW

Node result						
Node	Voltage (kV)	Voltage angle (°)	Load (MW)	Load (MVAr)	Generation (MW)	Generation (MVAr)
Bus1	241.5	0.00	0	0	70.1	8.6
Bus2	241.5	7.26	20	0	120	-13.9
Bus3	237.2	-4.60	85	0	0	0
Bus4	236.9	-4.19	40	0	0	0
Bus5	236.3	-5.71	20	0	0	0
Bus6	235.4	-7.03	20	0	0	0
Total	-	-	185	0	190.1	-5.3

Line flow result					
Line	P_{sent} (MW)	Q_{sent} (MVAr)	Losses (MW)	Losses (MWAr)	Loading in % of max limit
L1	48.89	2.30	0.74	1.62	57
L2	35.82	-3.60	1.33	-0.67	50
L3	28.35	-6.67	0.68	-2.69	40
L4	5.91	-3.18	0.01	-1.46	8
L5	17.19	-0.39	0.06	-1.17	24
L6	48.89	2.29	0.75	1.62	57
L7	35.82	-3.60	1.33	-0.67	50
L8	23.08	-2.69	0.12	-0.89	32
L9	20.09	-1.03	0.09	-1.03	28

the buses is modelled in detail in accordance to [9]. Table VI shows the additional number of components that are included in the model compared to RBTS(1). The total number of assessed components is 87 (9+32+32+14). The generators and disconnectors are included in the system model, but are assumed to be 100% reliable.

The circuit breakers and transformers include both an active failure mode and a maintenance outage mode. It is assumed that a component is not taken out for maintenance if it causes system violations.

F. Load flow results for intact system

Table VII shows the load flow result for an intact RBTS(1) and RBTS(2) during the peak load. The table shows that the north-to-south lines L1, L2, L6 and L7 are relatively high loaded during this load situation. These four lines are normally the bottlenecks of the system, due to the large power flows from the production areas in north to the consumptions in south.

G. Implementation of RBTS

The two models of RBTS have been implemented in the commercial computer program Neplan by BCP [14]. For each outage event the influences on the system's load and generation, tripping of circuit breakers etc., is displayed to the user in a failure effect analysis (FEA). The FEA list also shows a time-stamped list of all corrective actions needed seconds or minutes after the event, such as e.g. manual disconnections of overloaded lines. Each event's effect on the line power flows may also be displayed. The program evaluates the outage events with an a.c. load flow method, and if this not converges it falls back on a d.c. load flow method.

V. RESULTS

The proposed method is applied on CTS 1 (i.e. line L1 and L6) in RBTS(1) and RBTS(2). Four discrete load levels from 0.7 to 1.0 p.u. of the peak load (185 MW) are studied in this paper. The load is scaled proportionally in all load points. The scheduled generation in Bus 2 is adjusted in each load level in order to keep the same generation proportion of Bus 1 and Bus 2 as for the system peak load. The maximum thermal transfer limit for CTS 1 is, given the sum of I_{max} for each line in Table II, 170 MW if a nominal voltage with a unity power factor is assumed. First and second order component outages are evaluated. The notation of e.g. L1+L2 includes both the outage event L1+L2 and L2+L1, which are treated identically.

A. RBTS(1) - CTS 1

Fig. 3 shows the general screening of the assessed outage events impact on CTS 1 in RBTS(1). The relative loading in CTS 1 for an intact system, and at a system peak load (1.0 p.u.), is 57% of the maximum. If e.g. the outage event L1 or L6 occurs, this results in a change of loading from 57% to 102% at this load level according to the upper right of Fig. 3. If the same events occur at a system load level of 0.9 p.u., the impact on CTS 1 is 90% of the maximum allowed transfer capacity. The events have an expected frequency of 1.5 times per year, as shown in the figure. Several events have identical positions in the diagram for all four system load levels, e.g. L1+L2 and L1+L7.

All events on the right hand of the dashed vertical line are overloads of the section and these are the risk-outages for CTS 1. The right column shows the total-outages, i.e. outage events that result in a 0 MW transfer capability for the CTS, and for which the risk index I_i^{Risk} is not defined. These outages are not dependent of the system load level.

Table VIII presents a ranking of the assessed outage events with the total-outage on top followed by the risk-outages which severity is quantified with (1) for each system load level. As shown both in Table VIII and in Fig. 3 no risk-outages results in an overload of the CTS for the 0.7 and 0.8 p.u. load levels. Four risk-outages results in an overload at the 0.9 p.u. level, and eight at the 1.0 p.u. load level.

Table IX shows the components cumulative risk, I_{Comp}^{Risk}, of overloading CTS 1 at four different system load levels. According to this table the loss of line L1 or L6 has the largest impact on CTS 1 transfer capability for the peak load scenario. This is expected since these two lines actual defines CTS 1. Moreover, a relatively frequent single component outage (L1 or L6) results in an overload for the CTS and this increase the ranking for these two components. L2 or L7 are the next components in the list, and this is explained by the re-direction of large active power flows from north-to-south through CTS 1 if these components suffer an outage. For the 0.9 p.u. load level, the components L1, L2, L6 and L7 are equally important for CTS 1 capability to transfer active power.

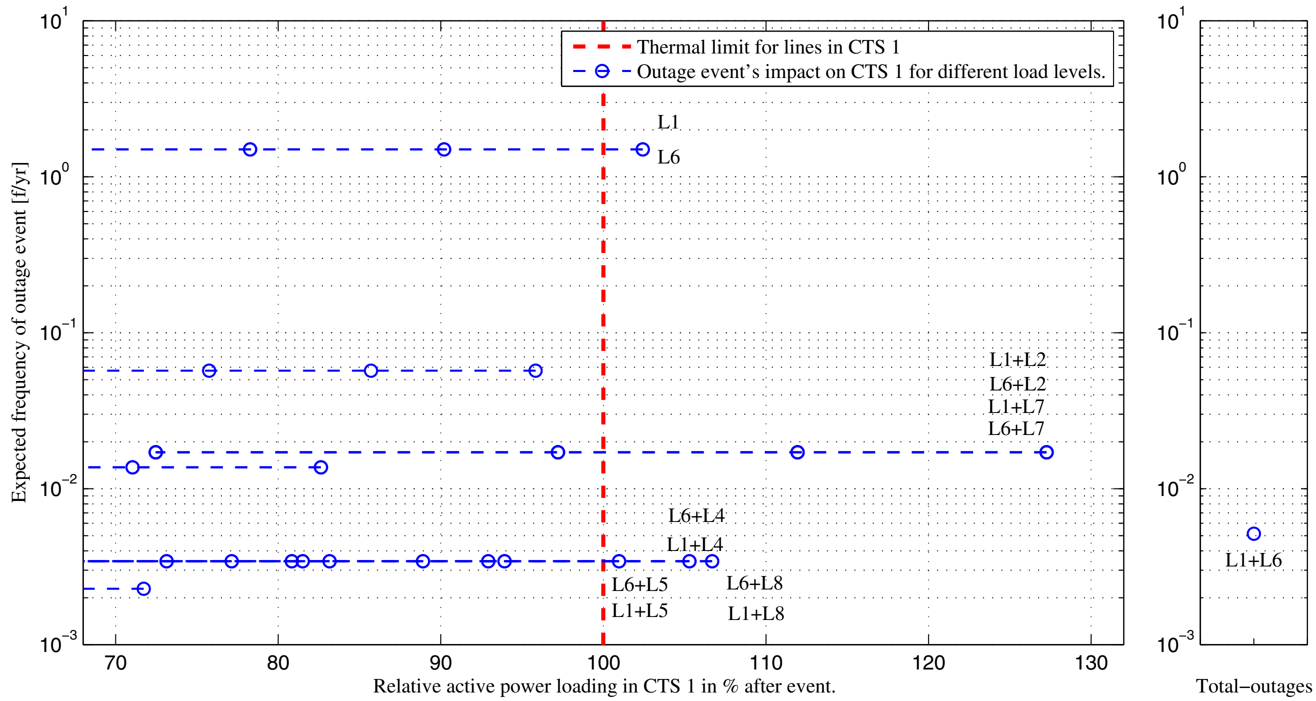

Fig. 3. Screening of 45 outage events impact on CTS 1 capability to transfer power in RBTS(1) at four different system load level scenarios from 0.7-1.0 p.u. of the peak load. For all events the 1.0 p.u. level represent the most right of the scenarios. The y-axis shows the expected frequency of the outage event to occur and the x-axis the resulting relative loading on the CTS after the event.

Since a single component outage (L1 or L6) result in an overload of CTS 1, it can be argued that the intact RBTS(1) does not fulfil the N-1 criterion for the peak load level. The system operator's implementation of the criterion may however permit such violations if the time for corrective actions is reasonable. Moreover, in RBTS the system load is in the interval 0.9-1.0 p.u. approximately 1.4% of the year [9], and this could also be taken into the consideration in the system planning.

B. RBTS(2) - CTS 1

Fig. 4 shows the general screening of the assessed outage events impact on CTS 1 in RBTS(2). Only a few names for the total 7395 assessed events at four different load levels are shown. The total computational time was approximately 40 min on an ordinary PC. The screening diagram provides a good overview of the outage events risks to the CTS at different system load levels, especially when the number of assessed events grows larger. The risk for events with large consequences but low expected frequencies can be evaluated and compared with events with the opposite situation. However, the severity of total-outages in the right side diagram is difficult to compare with risk-outages, since the consequence of the first category is infinite large for the CTS. The expected frequency of these events gives at least an indication of their associated risk.

Table X shows a selection of the resulting ranking of the total- and risk-outages. Total-outages are sorted by descending λ_i, and these are independent of the system load level. The risk-outages are sorted with a descending I_i^{Risk} for each studied load level. A number of events (e.g. L2+CB3:3) results in an overload in CTS 1 for all four load levels.

Table XI shows the resulting ranking of the components' cumulative risk of insufficient transmission capacity in CTS 1 in RBTS(2) for each studied load level. This result provides information of the assessed components' importance for CTS 1 capability to transfer active power in RBTS(2). The component ranking at each load level shows that the component importance is highly dependent of the system load level. At

TABLE VIII
OUTAGE EVENTS WITH IMPACT ON CTS 1 CAPABILITY TO TRANSFER ACTIVE POWER IN RBTS(1)

Outage event i	λ_i (f/yr) ($\times 10^{-2}$)	r_i (h)	Loading CTS 1 after event i (%), at system load (p.u) 0.7 - 0.8 - 0.9 - 1.0	Risk index I_i^{Risk} ($\times 10^{-6}$), at system load (p.u) 0.7 - 0.8 - 0.9 - 1.0
Total-outages[1]				
L1+L6	0.51	5	-	-
Risk-outages[2]				
L1+L2	1.71	5	72 - 97 - 112 - 127	0 - 0 - 12.2 - 15.8
L1+L7	1.71	5	72 - 97 - 112 - 127	0 - 0 - 12.2 - 15.8
L6+L7	1.71	5	72 - 97 - 112 - 127	0 - 0 - 12.2 - 15.8
L2+L6	1.71	5	72 - 97 - 112 - 127	0 - 0 - 12.2 - 15.8
L1	150	10	52 - 78 - 90 - 102	0 - 0 - 0 - 1796
L6	150	10	52 - 78 - 90 - 102	0 - 0 - 0 - 1796
L1+L8	0.34	5	56 - 82 - 94 - 107	0 - 0 - 0 - 2.23
L6+L8	0.34	5	56 - 82 - 94 - 107	0 - 0 - 0 - 2.23
L1+L4	0.34	5	57 - 81 - 93 - 105	0 - 0 - 0 - 2.22
L4+L6	0.34	5	57 - 81 - 93 - 105	0 - 0 - 0 - 2.22
L1+L5	0.34	5	52 - 77 - 89 - 101	0 - 0 - 0 - 1.99
L5+L6	0.34	5	52 - 77 - 89 - 101	0 - 0 - 0 - 1.99

[1] Total-outages always result in a 0 MW transfer capability for the CTS
[2] Risk-outages are events that result in a CTS overload ($\geq$100%) in at least one system load level.

TABLE IX
THE COMPONENTS' RISK OF OVERLOADING CTS 1 IN RBTS(1) AT FOUR DIFFERENT SYSTEM LOAD LEVELS

Component ($Comp$)	Associated risk, I_{Comp}^{Risk} ($\times 10^{-6}$), at system load level (p.u.):			
	0.7	0.8	0.9	1.0
L1	0	0	24	1834
L6	0	0	24	1834
L2	0	0	24	32
L7	0	0	24	32
L8	0	0	0	4.5
L4	0	0	0	4.3
L5	0	0	0	4.0
L3	0	0	0	0
L9	0	0	0	0

TABLE XI
TOP EIGHT COMPONENTS' RANKING OF OVERLOADING CTS 1 IN RBTS(2) AT FOUR DIFFERENT SYSTEM LOAD LEVELS

The components associated risk, I_{Comp}^{Risk} ($\times 10^{-6}$), at system load level (p.u.):							
0.7		0.8		0.9		1.0	
CB3:3	0.51	CB3:3	0.69	L1	41	L6	1887
L2	0.32	L1	0.53	L6	40	L1	1884
CB2:4	0.13	L2	0.42	L2	34	BB7:1	277
L1	0.10	CB5:2	0.32	L7	34	BB5:3	277
L8	0.06	L6	0.31	TR_G9	11	BB4:1	277
CB1:4	0.06	CB6:2	0.26	TR_G8	11	BB3:3	277
BB4:1	0.01	CB9:2	0.25	TR_G7	9	CB3:3	65.9
BB3:3	0.01	CB2:4	0.18	BB4:1	6	CB4:1	62.1

TABLE X
OUTAGE EVENTS WITH IMPACT ON CTS 1 CAPABILITY TO TRANSFER ACTIVE POWER IN RBTS(2)

Outage event i	λ_i (f/yr) $\times 10^{-2}$	r_i (h)	Loading CTS 1 (%) after event i, system load(p.u) 0.7-0.8-0.9-1.0	Risk index I_i^{Risk} ($\times 10^{-6}$), at system load(p.u) 0.7-0.8-0.9-1.0
Total-outages				
L1+L6	0.51	5	-	-
BB5:3+L1	0.07	5	-	-
...	*(48 additional total-outages not displayed here)*			
6 selected Risk-outages				
L2+CB3:3	0.031	9	101-117-133-149	0.32-0.42-0.55-0.69
L1+CB2:4	0.009	9	102-117-133-150	0.10-0.13-0.16-0.21
L8+CB3:3	0.006	9	102-117-133-150	0.06-0.08-0.11-0.14
L1+L2	1.71	5	72- 97-112-127	0- 0-12.2-15.8
L2+L6	1.71	5	72- 97-112-127	0- 0-12.2-15.8
L1	150	10	67- 78- 90-102	0- 0- 0-1797
...	*(864 additional risk-outages not displayed here)*			

1.0 p.u, the eight most important components are the two lines in CTS 1, the four connecting BBs at each side of the two lines, and associated circuit breakers to these BBs. The results for each line and their associated components in the substations are symmetrical. This is not the case at the system load level 0.7 p.u., where e.g. the line L1 is present, but not L6. The system topology and substation design seems to be more important to the result at lower load levels. One example is the circuit breaker CB3:3, located in Bus 3 between the ingoing lines L1 and L4 (see Fig. 2), which is top ranked for the 0.7 and 0.8 p.u. load level. It is included in a number of high ranked risk-outages, e.g. L8+CB3:3 which results in the tripping of L1, L4 and L8, and all power to Bus 5 and Bus 6 is redirected via the remaining line L6 in CTS 1.

VI. DISCUSSION

The presented method provides a systematic analysis and ranking of outage events' risks on insufficient transfer capacity for one or more selected CTSs at different load levels. Hence, it is not an assessment of the overall transmission system security. An outage event may have a small impact on one CTS, but yet result in severe consequences for the overall system security. However, if the assessed CTSs represent the actual transmission bottlenecks in the system, the method provides the potential risk outages for the overall system transfer capability, which gives an indication of the risks to the overall system security for the assessed load levels.

The index I_i^{Risk} in (1) increase in quadrate with the overload at the CTS. This definition is physical justified if the transfer limit for the CTS is set by thermal properties. The limit can however be arbitrary set in the method and then the quadrate property may be reassessed. One example is when the maximum allowed transfer limit is set in respect to fulfil the N-1 criterion given voltage or angel instability constraints.

The outage restoration time r_i in I_i^{Risk} capture how long the system is going to be in a strained condition during the restoration of the components in the outage event. One alternative is to let r_i represent the time it takes to perform corrective actions by the operator, although this parameter can be difficult to estimate.

The result of the component importance ranking in RBTS(2) shows that this is highly dependent on the studied load level and the substation design. Hence, the impact of alternative substation configurations would be interesting to investigate.

An annual component ranking, based on the component ranking for a number of discrete load levels and their expected durations, is left for future work.

VII. CONCLUSIONS

This paper has presented a method for quantifying the transmission system components' contribution to the risk of insufficient power transfer capacity in CTSs. The result is a ranking of the potential risk events, and the most important components for each CTS and load level. This result can be used in the future decision making in transmission system planning and system expansion.

With the restriction of only evaluating the consequences in a few transfer sections in the system, the proposed method provides a quantitative measure on the potential risks to the system security at different load levels.

Further analysis on larger power systems and with other transfer limits than thermal may show the feasibility of the proposed method on existing systems. For large systems the computational speed of the method may be necessary to improve with a more efficient selection of the analysed outage events.

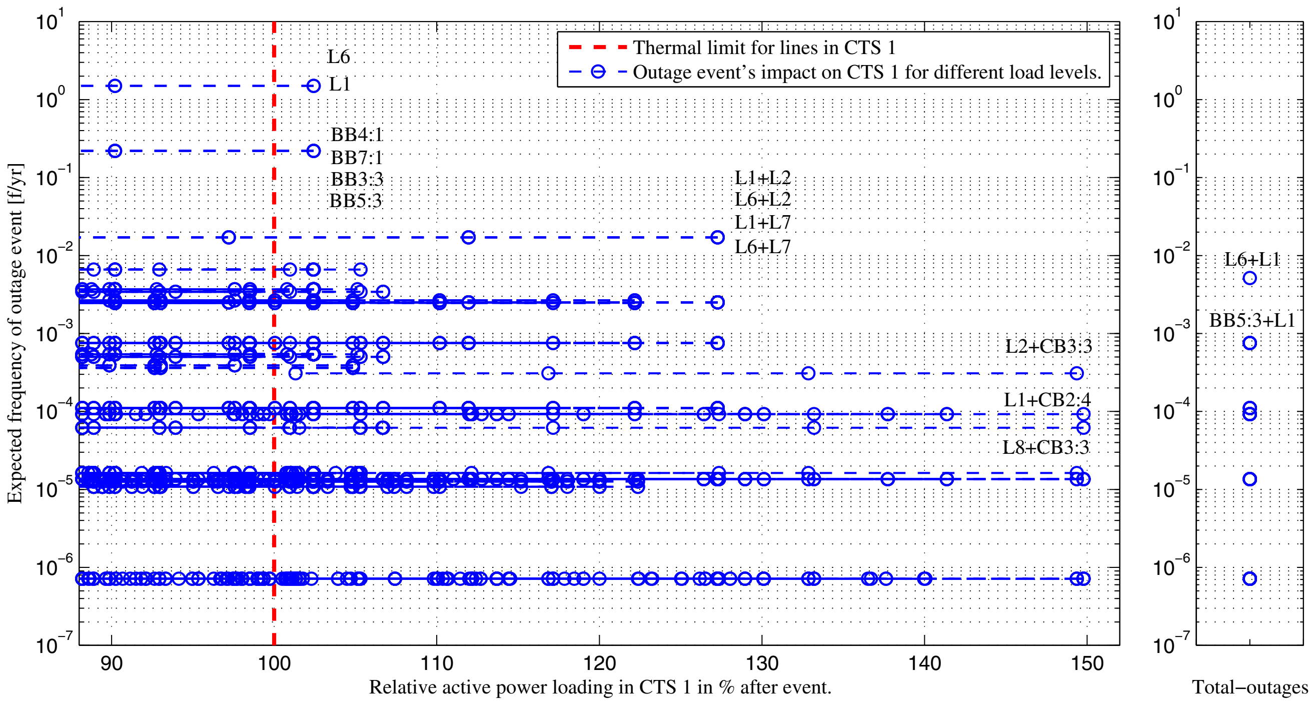

Fig. 4. Screening of outage events impact on CTS 1 capability to transfer power in RBTS(2) at four different system load level scenarios from 0.7-1.0 (p.u.). Only 15 names of the 7395 assessed outage events are printed out in the figure. Of these 870 are risk-outages located at the right hand of the dashed vertical line, and 50 total-outages.

References

[1] R. Billinton and E. Khan, "A security based approach to composite power system reliability evaluation," *IEEE Transactions on Power Systems*, vol. 7, no. 1, pp. 65–72, Feb. 1992.

[2] A. M. L. da Silva, L. C. de Resende, L. A. da Fonseca Manso, and R. Billinton, "Well-being analysis for composite generation and transmission systems," *IEEE Transactions on Power Systems*, vol. 19, no. 4, pp. 1763–1770, Nov. 2004.

[3] Y. Dai, J. D. McCalley, N. Abi-Samra, and V. Vittal, "Annual risk assessment for overload security," *IEEE Power Engineering Review*, vol. 21, no. 10, pp. 59–59, Oct. 2001.

[4] R. Billinton and R. Allan, *Reliability Evaluation of Power Systems*, 2nd ed. Plenum publishing corporation, 1994, ISBN 0-306-45259-6.

[5] *IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems*. IEEE Std 493-2007, February 2007.

[6] Nordel (association of transmission system grid owners in the Nordic countries), *Nordic Grid Code*, 2007, Available at: http://www.nordel.org.

[7] Svenska Kraftnät (SvK), the Swedish national grid company, "Elavbrottet 23 september 2003," SvK, Tech. Rep., 2003, (In Swedish).

[8] A. Merlin, J.P. Desbrosses, "European incident of 4th November 2006 the events and the first lessons drawn," *Electra*, no. 230, February 2007.

[9] R. Billinton et al, "A reliability test system for educational purposes-basic data," *IEEE Transactions on Power Systems*, vol. PWRS-3, no. 4, pp. 1238–1244, Aug 1989.

[10] R. Billinton, S. Kumar, N. Chowdhury, K. Chu, L. Goel, E. Khan, P. Kos, G. Nourbakhsh, and J. Oteng-Adjei, "A reliability test system for educational purposes-basic results," *IEEE Transactions on Power Systems*, vol. 5, no. 1, pp. 319–325, Feb. 1990.

[11] R. N. Allan, R. Billinton, I. Sjarief, L. Goel, and K. S. So, "A reliability test system for educational purposes-basic distribution system data and results," *IEEE Transactions on Power Systems*, vol. 6, no. 2, pp. 813–820, May 1991.

[12] Subcommittee, P. M., "IEEE reliability test system," *IEEE Transactions on Power Apparatus and Systems*, vol. 98, no. 6, pp. 2047–2054, Nov. 1979.

[13] W. Wangdee, "Bulk electric system reliability simulation and application," Ph.D. Thesis, University of Saskatchewan, 2005.

[14] BCP Busarello + Cott + Partner AG, "NEPLAN, power system analysis," 2008, www.neplan.ch.

Johan Setréus (S'06) was born in Stockholm 1980. He received his M.Sc. at KTH School of Electrical Engineering in 2006, and has since then been pursuing the Ph.D. degree at the same school. His research interest includes reliability models and methods to combine traditional deterministic criterions and planning policies in the transmission system with probabilistic techniques.

Stefan Arnborg (M'97) was born in Gävle 1964. He received his Tech. Lic and Ph.D. degree in Electric Power Systems, KTH, in 1994 and 1997, respectively. In 1997 he joined Svenska Kraftnät, the Swedish national grid company. Within Svenska Kraftnät he has worked with system planning, system reliability, disturbance analysis, protection and control. Currently he works with questions related to system preparedness, security and system reliability demands on production units.

Roland Eriksson (SM'83) received the M.Sc. and Ph.D. degrees in electrical engineering from the Royal Institute of Technology (KTH), Stockholm, Sweden in 1969 and 1975, respectively. Since 1988 he has been a professor and Head of the Department of Electrical Engineering at KTH. His research interests include diagnostics of electrical insulation, insulation co-ordination, modeling of electrotechnical equipment and reliability assessment of distribution systems.

Lina Bertling (SM'08) is Professor in Sustainable Electric Power Systems and Head of the Division of Electric Power Engineering, at the Department of Energy and Environment, at Chalmers University of Technology, in Gothenburg, Sweden. She has been with Svenska Kraftnät, i.e. the Swedish Transmission System Operator during 2007-2009. She has been with KTH School of Electrical Engineering (EES), in Stockholm, during 1997-2009 were she finalized her Docent degree and became Associate Professor in 2008, and Ph.D. in 2002 all in Electric Power Systems. At KTH she has been the founder of the RCAM (Reliability-Centred Asset Management) research group. She was a visiting postdoctoral student at the University of Toronto, associated with Kinectrics Inc. during 2002/2003. Dr. Bertling is a senior member of IEEE and a member of Cigré, Cired and the Royal Swedish Academy of Engineering Sciences (IVA).