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Risk-based Maintenance Allocation and Scheduling for Bulk Electric Power Transmission System Equipment

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Abstract

This paper describes a new maintenance selection and scheduling approach for bulk transmission equipment that is based on the cumulative long-term risk caused by each piece of equipment. This approach not only accounts for equipment failure probability and equipment damage, as do most state of the art reliability centered maintenance (RCM) approaches, but it also accounts for the outage consequence in term of overload and voltage security in a rigorous and systematic way. The method is illustrated on the IEEE reliability test system (RTS).

Keywords: Power system, generator and transmission equipment, maintenance, reliability, risk, security, optimization

1.Introduction

Maintenance of bulk electric transmission and generator equipment requires significant economic resources, and the industry is decidedly willing to expend these resources as the consequences of equipment failure can be large. The objective of the work reported in this paper is to develop a method of allocating economic resources and scheduling maintenance activities among bulk transmission system equipment so as to optimize the effect of maintenance with respect to the mitigation of component failure consequences. The central concept is that allocation of available economic resources for performing maintenance on a large number of facilities can be done strategically, as a function of cumulative-over-time system risk associated with network security problems such as overloads, low voltages, cascading overloads, and voltage instability, so as to minimize risk of wide-area bulk transmission system failures.

The work makes use of two previously developed technologies: risk-based security assessment and long-term sequential simulation. Risk-based security assessment [1,2] provides quantitative valuation of network security level, risk, using probabilistic modeling of uncertainties in loading conditions and contingency states. We developed a simulator [3,4,5] that performs sequential long-term simulation of a power system on an hour-by-hour basis. It creates an 8760-hour trajectory of operating conditions. The trajectory is formed by developing an hour by hour load forecast, identifying and modeling the load forecast error, identifying a generation and circuit maintenance schedule, and developing a unit commitment schedule.

The long-term simulator, when integrated with hourly risk-based security assessment capability, provides year- long hourly risk variation for each contingency of interest. This information, when combined with a set of proposed maintenance activities and corresponding contingency probability reductions, yields cumulative (year-long) risk reduction (CRR) associated with each maintenance activity and associated possible start times. This overall process, (1) long term simulation with risk-based security assessment, (2) risk reduction calculation, and (3) optimal selection and scheduling, comprise what we call the integrated maintenance selection and scheduler (IMSS), illustrated in Fig 1. In this paper, we describe and illustrate the IMSS, including the long-term simulator (Section 2), risk reduction calculations (Section 3), the selection of possible maintenance tasks and the effect that each maintenance task has on contingency probability (Section 4), the optimization problem associated with the maximization of risk reduction (Section 5), and illustration (Section 6).

2. Long-term Simulation with Risk Assessment

Cumulative risk assessment is useful in evaluating the system from an operation planner's perspective. It performs sequential, hourly simulation over a long term, e.g., 1 year, and it evaluates the security levels in terms of quantitative indices, reflecting risk of overload, cascading overload, low voltage, and voltage instability. The risk index R is an expectation of severity, computed as the product of contingency c probability $p(c)$ with contingency severity $sev(c|m,t)$, where m indicates the m^{th} maintenance activity (and thus the network configuration in terms of network topology and unit commitment), and t indicates the hour (and thus the operating conditions in terms of loading and dispatch), given by $R(c,m,t)= p(c)sev(c|m,t))$. A reference "basecase" network configuration (with no maintenance activity) is denoted with $m=0$. The severity function captures the contingency severity in terms of overload, cascading overload, low voltage, and voltage instability. The risk associated with any given network configuration and operating condition is computed by summing over the no-contingency condition (c=0) and all N contingencies:

$$R(m,t)=\sum_{c=0}^{N} p(c)sev(c\mid m,t) \qquad (1)$$

Even if there are no maintenance activities and contingency probabilities are constant, risk still varies with time because operating conditions, and therefore contingency severities, vary with time.

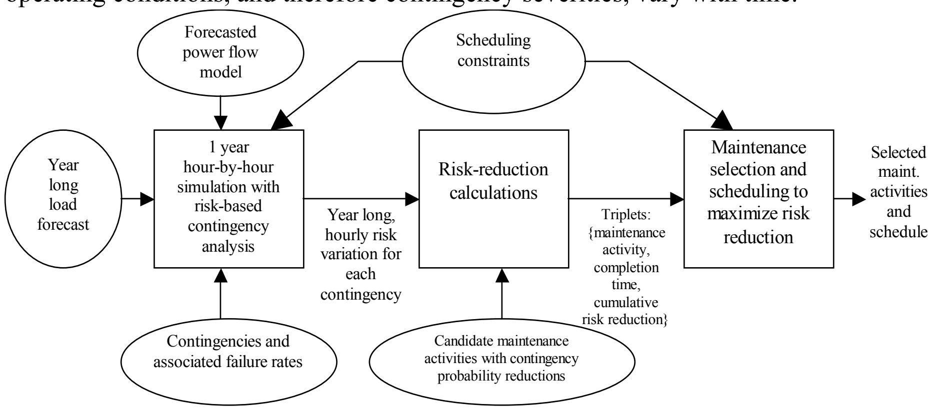

Fig. 1: Integrated Maintenance Selector and Scheduler (IMSS)

Three basic modules are required for use with the long-term cumulative risk assessment simulator, including load forecasting, unit commitment, and contingency set selection. The specific implementation used for each of these modules is interchangeable. The sequential approach used in our simulator evaluates a trajectory of operating conditions over time. The key features that drive the design are: (1) *Hourly assessment*: In making a one-year risk computation, some components may see their highest risk during off-peak or partial-peak conditions, when weak network topologies, weak unit commitment patterns, or unforeseen flow patterns are more likely to occur. (2) *Sequential simulation*: Load-cycles, weather conditions, unit shut-down and start-up time, or maintenance strategies are examples of chronologically dependent constraints that can affect reliabilities in ways that the snapshot models cannot capture. Thus, we require that the simulations be sequential in time.

3. Risk reduction calculations

The probability of failures decreases after a maintenance activity; otherwise the maintenance activity should not be performed. Given the hourly system risk variation over an extended period such as a year, we want to determine how different maintenance activities reduce the risk as a function of time when they are scheduled during the year. We assume that each maintenance activity decreases the probability of a particular contingency, and therefore probability reductions are in force from the maintenance activity completion time until the end of the year. Thus, each maintenance activity creates a risk reduction that is a function of its completion time. In addition, risk may increase during the maintenance activity due to the system weakening from possible maintenance outage. These ideas are captured analytically by defining a particular maintenance activity m known to decrease the probability of contingency k by $\Delta p(m,k)$. The cumulative-over-time risk reduction due to maintenance activity m is $\Delta CR(m,t_f)$, computed as a function of the completion time t_f according to:

$$\Delta CR(m,t_f)=\Delta CR_{during}(m,t_f)+\Delta CR_{after}(m,t_f)=\int_{t_f-T_d}^{t_f}(R(0,t)-R_{during}(m,t))dt+\int_{t_f}^{8760}(R(0,t)-R_{after}(m,t))dt \qquad (2)$$

where T_d is the duration of the maintenance activity, $R(0,t)$ is the risk variation over time for with no maintenance, and $R(m,t)$ is the risk variation over time with maintenance. The first integral in (2) is the risk reduction during the maintenance period, always non-positive indicating that risk may increase during the maintenance period. The second integral in (2) is the risk reduction after completion of the maintenance activity, always positive due to the decrease in failure probability. In each integral, $R(0,t)$ is obtained from the long-term simulator. If, during the maintenance period, no component is outaged, then $\Delta CR_{during}=0$. However, if the maintenance activity requires removal of component k (a generator, line, transformer, circuit breaker), then $\Delta CR_{during}<0$ because of changes in operating conditions, e.g., voltages, flows, etc., which change the severity of *all* contingencies except contingency k (contingency k cannot occur due to the fact that the corresponding component is on maintenance outage). Therefore, the risk "reduction" during maintenance activity m is:

$$\begin{aligned}\Delta CR_{during}(m,t_f)&=\int_{t_f-T_d}^{t_f}[R(0,t)-R(m,t)]dt=\int_{t_f-T_d}^{t_f}[\sum_{c=0}^{N}p(c)sev(c\mid 0,t)-\sum_{c=0,c\neq k}^{N}p(c)sev(c\mid m,t)]dt\\&=\int_{t_f-T_d}^{t_f}[p(k)sev(k\mid 0,t)+\sum_{c=0,c\neq k}^{N}p(c)\big(sev(c\mid 0,t)-sev(c\mid m,t)\big)]dt\end{aligned} \qquad (3)$$

Now consider the second integral in (2), the risk reduction after the maintenance activity. Here, the maintenance activity m reduces contingency k probability by $\Delta p(m,k)$ but does not affect the contingency k severity. We assume that maintenance activity m affects only contingency k probability and no others. The risk reduction after maintenance activity m is

$$\Delta CR_{after}(m,t_f)=\int_{t_f}^{8760}\{R(0,t)-R_{after}(m,t)\}dt=\int_{t_f}^{8760}\left(\left(p(k)sev(k\mid 0,t)+\sum_{\substack{c=0\\c\neq k}}^{N}p(c)sev(c\mid 0,t)\right)-\left((p(k)-\Delta p(m,k))sev(k\mid 0,t)+\sum_{\substack{c=0\\c\neq k}}^{N}p(c)sev(c\mid m,t)\right)\right)dt \tag{4}$$

where we have pulled from each summation the risk associated with contingency k, since contingency k is the only one having a probability affected by the maintenance activity. After t_f, component k is back in service, and the operating conditions are unchanged relative to the case of no maintenance; therefore $sev(c|0,t)=sev(c|m,t)\ \forall\ c=1,\ldots,N$, and the two summations within the integral of (4) are equal so that:

$$\Delta CR_{after}(m,t_f)=\int_{t_f}^{8760}\{p(k)sev(k\mid 0,t)-(p(k)-\Delta p(m,k))sev(k\mid 0,t)\}dt=\int_{t_f}^{8760}\{\Delta p(m,k))sev(k\mid 0,t)\}dt \tag{5}$$

Denoting the contingency k risk, without maintenance, as $R(0,k,t)$, we have $sev(k|0,t)=R(0,k,t)/p(k)$, so that

$$\Delta CR_{after}(m,t_f)=\int_{t_f}^{8760}\Delta p(m,k)\left\{\frac{R(0,k,t)}{p(k)}\right\}dt=\frac{\Delta p(m,k)}{p(k)}\int_{t_f}^{8760}R(0,k,t)dt \tag{6}$$

Substituting (3) and (6) into (2), and replacing $p(k)sev(k|0,t)$ in (3) by $R(0,k,t)$, results in the following expression for the total risk reduction associated with maintenance activity m completed at time t_f:

$$\Delta CR(m,t_f)=\int_{t_f-T_d}^{t_f}[R(0,k,t)+\sum_{c=0,c\neq k}^{N}p(c)\big(sev(c\mid 0,t)-sev(c\mid m,t)\big)]dt+\frac{\Delta p(m,k)}{p(k)}\int_{t_f}^{8760}R(0,k,t)dt \tag{7}$$

We see that in order to obtain the change in cumulative risk due to a maintenance activity, we need to evaluate the two integrals. The first integral requires $p(c)$ for all contingencies $c=0,N$ (which we assume to be available), the severity of all contingencies associated with the basecase configuration $(0,t)$, and the severity of all contingencies occurring under the weakened configuration (m,t). The contingency severities associated with the basecase configuration comes from one run of the simulator, but the contingency severities associated with configuration (m,t) would require rerunning the simulator for every weakened condition, i.e., for every maintenance activity m, and would be excessively computational. Thus we evaluate the first integral using approximate methods. For example, one might evaluate the severities associated with configuration (m,t) under the assumption that severity is linear, superposition holds, and the severity of removing two lines is the sum of the severity of removing each line alone. Alternatively, one might assume that maintenance activity m, which requires removal of component k, causes no change in severity so that $sev(c|0,t)=sev(c|m,t)$, and the summation in the first integral of (7) is 0. This might be true as a result of, for example, operator initiated system adjustments during the maintenance period. We accept this assumption for the remainder of the paper with intentions to study methods of relieving it in the future. Under this assumption, the total risk reduction associated with maintenance activity m completed at time t_f is

$$\Delta CR(m,t_f)=\int_{t_f-T_d}^{t_f}R(0,k,t)dt+\frac{\Delta p(m,k)}{p(k)}\int_{t_f}^{8760}R(0,k,t)dt \tag{8}$$

Thus, we need $R(0,k,t)$, the risk variation for each contingency affected by a maintenance activity under the basecase configuration, information obtained from a simulator run. In (8), the first term indicates the risk reduction accrued during the maintenance period because contingency k cannot occur and in general will be quite small. If one assumes, as we have above, that maintenance outages cause no severity increase, then it is reasonable to also neglect the first term in (8). This leaves us with the important problem of how to obtain contingency probability decrease $\Delta p(m,c)$ due to the maintenance activity m. We address this in Section 4. There may also be situations where it is desirable to schedule simultaneous maintenance activities. Although contingency probability reductions are independent in such cases, the severity increases due to the planned maintenance outage are not. Consider the simultaneous maintenance activities illustrated in Fig 2. The total cumulative risk reduction is:

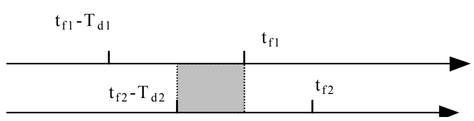

Fig 2. Simultaneous maintenance activities

$$\Delta CR(m_1,m_2,t_{f1},t_{f2})=\Delta CR_{during\ m_1}+\Delta CR_{\substack{during\ m_1\\during\ m_2}}+\Delta CR_{\substack{after\ m_1\\during\ m_2}}+\Delta CR_{\substack{after\ m_1\\after\ m_2}}$$

$$\begin{aligned}
&=\int_{t_{f1}-T_{d1}}^{t_{f2}-T_{d2}}R(0,k_1,t)+\sum_{\substack{c=0\\c\neq k_1}}^{N}p(c)(sev(c\mid 0,t)-sev(c\mid m_1,t)dt+\int_{t_{f2}-T_{d2}}^{t_{f1}}R(0,k_1,t)+R(0,k_2,t)+\sum_{\substack{c=0\\c\neq k_1,k_2}}^{N}p(c)(sev(c\mid 0,t)-sev(c\mid m_1,m_2,t))dt\\
&\quad+\int_{t_{f1}}^{t_{f2}}R(0,k_1,t)+R(0,k_2,t)+\sum_{\substack{c=0\\c\neq k_1,k_2}}^{N}p(c)(sev(c\mid 0,t)-sev(c\mid m_2,t))-R(m_2,k_1,t)+\frac{\Delta p(k_1,m_1)}{p(k_1)}R(m_2,k_1,t)dt\\
&\quad+\int_{t_{f2}}^{8760}\frac{\Delta p(k_1,m_1)}{p(k_1)}R(0,k_1,t)+\frac{\Delta p(k_2,m_2)}{p(k_2)}R(0,k_2,t)dt
\end{aligned} \tag{9}$$

Under the assumption that maintenance activities do not affect severity, severity function differences in (9) are zero, leaving

$$\Delta CR(m_1,m_2,t_{f1},t_{f2}) = \int_{t_{f1}-T_{d1}}^{t_{f2}-T_{d2}} R(0,k_1,t)dt + \int_{t_{f2}-T_{d2}}^{t_{f1}} R(0,k_1,t) + R(0,k_2,t)dt + \int_{t_{f1}}^{t_{f2}} R(0,k_2,t) + \frac{\Delta p(k_1,m_1)}{p(k_1)} R(m_2,k_1,t)dt + \int_{t_{f2}}^{8760} \frac{\Delta p(k_1,m_1)}{p(k_1)} R(0,k_1,t) + \frac{\Delta p(k_2,m_2)}{p(k_2)} R(0,k_2,t)dt \quad (10)$$

Neglecting risk reduction as a result of the maintenance outage, then (10) becomes

$$\Delta CR(m_1,m_2,t_{f1},t_{f2}) = \int_{t_{f1}}^{t_{f2}} \frac{\Delta p(k_1,m_1)}{p(k_1)} R(m_2,k_1,t)dt + \int_{t_{f2}}^{8760} \frac{\Delta p(k_1,m_1)}{p(k_1)} R(0,k_1,t) + \frac{\Delta p(k_2,m_2)}{p(k_2)} R(0,k_2,t)dt \quad (11)$$

4 Maintenance Induced Contingency Probability Reductions

We assume that component maintenance results in a reduction in the component failure probability. In order to perform the risk reduction calculation in Section 3, we need to identify relationships between maintenance activities and failure probability reductions. There are 3 basic steps: (a) identify the failure modes affected by each maintenance activity, (b) identify the reduction in failure mode probability and each maintenance activity, and (c) determine the relationship between the failure mode probability and the contingency probability. For step (a), we identified failure modes affected by each maintenance activity based on literature review [6-10] and interaction with industry engineers, resulting in a database of maintenance activities and corresponding failure modes for generators, lines, transformers, and circuit breakers.

To obtain contingency probability reduction caused by maintenance, step (b), we need the failure mode probabilities before and after each maintenance activity. Accordingly, we divide the modes into 2 types: deterioration and non-deterioration (random). Physical assets are subjected to a variety of stresses. These stresses cause the asset to deteriorate by lowering its resistance to stress. Eventually this resistance drops to the point at which the asset can no longer deliver the desired performance – it fails. Exposure to stress is measured in a variety of ways including output, operating cycles, times of operation, calendar time, or running time. In [11], six types of patterns are given representative of most kinds of aging and deterioration, as shown in Fig. 3. Pattern A is the well-known bathtub curve. It begins with a high incidence of failure (known as infant mortality) followed by a constant or gradually increasing failure probability, then by a wear-out zone. Pattern B shows constant or slowly increasing failure probability, ending in a wear-out zone. Pattern C shows slowly increasing failure probability, but there is no identifiable wear-out age. Pattern D shows low failure probability when the item is new, then a rapid increase to a constant level, while pattern E shows a constant failure probability at all ages. Pattern F starts with high infant mortality, which drops eventually to a constant or very slowly increasing failure probability. For a random failure, the failure probability in any short time interval, assuming that the device has been working up to that time, is constant. The time until failure is exponentially distributed and the hazard rate has the same shape of Pattern E in Fig. 3 [12,13]. Because random failure modes have constant failure probabilities, maintenance has no influence.

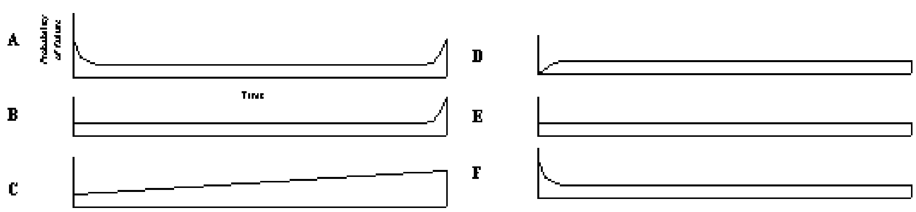

Fig 3: Probability of failure (hazard rates) caused by aging and deterioration

Fault tree analysis is used to derive the relationships between contingency probabilities and failure mode probabilities, step (c). The fault tree approach is a deductive process whereby an undesirable event, the top event, is postulated, and possible ways for this event to occur are systematically deduced. Only those failure modes that contribute to the occurrence of the top event are modeled, and only those events important to the analysis of interest need to be included. At each intermediate point, the postulated events represent the immediate, necessary, and sufficient causes for the occurrence of the top events. The fault tree is a logic model, and, thus, it represents qualitative characterization of system logic. We model the top event as a certain contingency; the intermediate layer represents functional failures causing the contingency; the lowest layer represents failure modes causing the corresponding failure.

5 Maximizing risk reduction

As indicated in Fig. 1, we first run the simulator to compute risk as a function of time for each hour over a long-term such as a year and then, for the example of this paper, use (8) to compute risk reduction associated with each proposed maintenance activity. This step results in triplets comprised of: {maintenance activity, completion time, risk reduction}. These triplets serve as the input to an optimization problem. We formulate the optimization problem so that maintenance activities for generation and transmission may be scheduled simultaneously or sequentially. Simultaneous scheduling is attractive because it results in a global optimum. Yet, sequential scheduling reduces problem complexity, and it also conforms to the fact that generation and transmission maintenance are performed by at least 2 companies having distinct budget and crew constraints. In sequential scheduling, generation maintenance is scheduled first because long maintenance times and high maintenance costs makes generation maintenance less flexible than transmission maintenance.

Let N be the total number of maintainable generators, N_i the number of maintenance *levels* for generator i, M is the total number of maintainable transmission components, and M_m is the number of maintenance *levels* for component m. Let $i=1,...,N$ be the index over the set of generators, $m=1,...,M$ be the index over the set transmission components, $j=1,...,N_i$ be the index over the set of maintenance activities for unit i, $n=1,...M_m$ be the index over the set of maintenance activities for transmission component m, and $t=1,...T$ be the index over the time periods.

For generator maintenance, define $IsSelect(i,j,t)$=1 if the j^{th} maintenance task for generator i begins at time t, and 0 otherwise, $IsActive(i,j,t)$=1 if the j^{th} task for generator i is ongoing at time t, and 0 otherwise. Define d_{ij} to be the duration of task j for generator i, $cost_{ij}$ to be its cost, and $\Delta CR(i,j,t)$ to be its cumulative risk reduction if it begins at time t. (In Section 3, we used notation $\Delta CR(m,t)$; here, the additional argument is necessary because we have allowed various levels of each maintenance activity.) Let $Infeas_{i,j}$ be the set of time periods wherein task j for generator i cannot be performed. $Crew(i,j)$ is the required crew number for the j^{th} maintenance for generator i. $Crew_g$ is the total number of crews available for generator maintenance. Notation for transmission maintenance is similar.

We have developed two forms for the resulting optimization problem. In problem 1, we are constrained by a cost budget; this problem conforms to the situation where the scheduler is also paying for the maintenance activities as in the traditional vertically integrated industry. In problem 2, we are constrained by only feasible schedules submitted by equipment owners. This problem conforms to the competitive industry where, for example, the ISO schedules for a large number of equipment owners who pay for their own maintenance. Problem 1, constrained by a budget is:

$$Max(\sum_{i=1}^{N}\sum_{j=1}^{N_i}\sum_{t=1}^{T}\Delta CR(i,j,t)\times IsSelect(i,j,t)+\sum_{m=1}^{M}\sum_{n=1}^{M_m}\sum_{t=1}^{T}\Delta CR(m,n,t)\times IsSelect(m,n,t)) \tag{12}$$

Subject to (generator maintenance constraints):

$$\sum_{i=1}^{N}\sum_{j=1}^{N_i}\sum_{t=1}^{T}cost_{ij} * IsSelect(i,j,t)\le cost_{total} \tag{13}$$

$$\sum_{j=1}^{N_i}\sum_{t=1}^{T} IsSelect(i,j,t)\le 1,\ i=1,\cdots,N \tag{15}$$

$$IsActive(i,j,t)=\sum_{k=d_{ij}-t+1}^{t}IsSelect(i,j,k),\forall (i,j,t) \tag{17}$$

$$IsActive(i,j,t)=0,\forall t\in Infeas_{ij},\forall (i,j) \tag{19}$$

$$\sum_{i=1}^{N}\sum_{j=1}^{N_i} IsActive(i,j,t)*Crew(i,j)\le Crew_g,\forall t \tag{21}$$

$$IsSelect(i,j,t)\in\{0,1\},\forall (i,j,t)\ . \tag{23}$$

Subject to (transmission maintenance constraints):

$$\sum_{m=1}^{M}\sum_{n=1}^{M_m}\sum_{t=1}^{T}cost_{mn} * IsSelect(m,n,t)\le cost_{total.trans} \tag{14}$$

$$\sum_{n=1}^{M_m}\sum_{t=1}^{T} IsSelect(m,n,t)\le 1,\ m=1,\cdots,M \tag{16}$$

$$IsActive(m,n,t)=\sum_{k=d_{mn}-t+1}^{t}IsSelect(m,n,k),\forall (m,n,t) \tag{18}$$

$$IsActive(m,n,t)=0,\forall t\in Infeas_{mn},\forall (m,n) \tag{20}$$

$$\sum_{m=1}^{M}\sum_{n=1}^{M_m} IsActive(m,n,t)*Crew(m,n)\le Crew_t,\forall t \tag{22}$$

$$IsSelect(m,n,t)\in\{0,1\},\forall (m,n,t) \tag{24}$$

In addition, we add a constraint to ensure system security, i.e., $Risk(t)<Risk_{max}$; this constraint is particularly important under conditions the experience risk increase during maintenance outages. In this optimization problem, the objective (12) seeks to maximize the total cumulative risk reduction. The constraint (13), (14) represents the budget constraint. The constraint (15), (16) indicates that each unit is maintained at most once during the time frame. Constraints (19), (20) require that each maintenance task be performed only within its feasible time period. Constraint (21), (22) stipulate that the number of maintenance tasks ongoing during any period are limited by crew constraints. To solve this problem is to determine $IsSelect(i,j,t)$ and $IsSelect(m,n,t)$, which then determines $IsActive(i,j,t)$ and $IsActive(m,n,t)$.

In our sequential scheduling implementation, we assume no transmission maintenance, identify the optimal generation schedule, and then use the generation maintenance schedule as input to solve the transmission problem. We have developed heuristic solution algorithms for problems 1 and 2. Problem 1's solution algorithm follows:

1. For each hour t in the maintenance time frame, calculate $\Delta CR(i,j,t)$. If $t \in Infeas_{i,j}$, then $\Delta cumuRisk(i,j,t) = 0$.
2. Scale the $\Delta CR(i,j,t)$ curve by the corresponding maintenance cost $cost_{ij}$. Put all ΔCR/Cost curves in the waiting list.
3. Find the maximum ΔCR/Cost from the waiting list. Set $IsSelect(i,j,t)$=1 for the curve which maximizes this ratio.
4. Remove this curve from the waiting list and deduct from $cost_{total}$ the cost of this maintenance.
5. If the remaining budget is non-negative, put this maintenance task in the schedule, update the feasible time periods for all remaining tasks (so that a future task cannot be scheduled during the time period just scheduled) and go to step 4; else stop.

Problem 2's algorithm is similar to that of problem 1 except that we take ΔCR as the ranking index instead of ΔCR/Cost. Also, problem 2 algorithm terminates when all projects are scheduled rather than when the budget is depleted.

The benefits of using these heuristic algorithms are that they are fast and that they always provide a feasible solution. However, the solutions, although usually good, are sub-optimal. Here, we desire to use formal methods including LaGrangian relaxation, tabu search, and branch and bound (B&B). Here, we report on an implementation of the B&B. This algorithm ranks each maintenance activity, first for the generators and then for the transmission, in order of their ΔCR/Cost ratio. Once the projects have been ranked, the algorithm enumerates possible sequences until the optimal one is found. The rank is used to determine the order in which the various sequences are considered. In each iteration, a bound is computed for a partial sequence as follows: each unit/trans project that is included in the sequence is scheduled at its earliest possible time given its place in the sequence. In this implementation, we have assumed (as we did in the heuristic approach) that no two generation activities be simultaneously ongoing, nor can any two transmission activities, although a generation activity can be scheduled simultaneous with a transmission activity. All remaining projects are given the cumulative risk reduction (CRR=ΔCR) they would attain if they were scheduled as soon as possible following the final generator or transmission activity in the sequence. No transmission projects are sequenced until all generation projects have been fully scheduled.

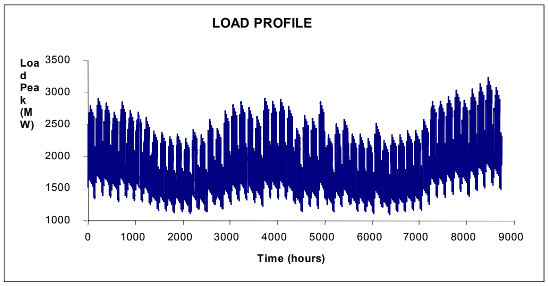

Fig 4: 1-year loading trajectory

Maint. ID	Unit ID	Cost ($)	Start Time-End Time (hour)	CRR
GM0001	Unit 1	106000	1-336	18.520
GM0003	Unit 9	93000	716-1219	0.429
GM0004	Unit 14	112290	4096-4767	6.120
GM0002	Unit 3	82840	2773-3276	2.571
GM0005	Unit 19	18000	337-672	4.491
Total		412130		32.13

Table 1: Unit maintenance schedule

6. Illustration

We have performed preliminary testing of the procedure, including both transmission and generation maintenance, using the IEEE Reliability Test System-1996 (RTS-96) [14] with hypothetical maintenance activities, based on the heuristic scheduling approach. Testing results suggest the approach is useful and computationally feasible. The expected hour-by-hour 1-year loading trajectory used in the analysis is shown in Fig.4.

We assume the generator maintenance budget to be $420000. The final generator maintenance schedule is shown in Table 2**.** We repeat the long-term simulation based on this schedule to obtain the risk information for transmission scheduling. The composite cumulative risk for each branch contingency is shown in Fig. 5.

Contingencies 11 and 41 correspond to high-risk. Contingency 11 is the outage of transmission line between Bus 6 and 10. Contingency 41 is the outage of transmission lines between Bus 15 and 21. The composite risks (low voltage + overload + voltage instability) over a year for contingency 11 and for contingency 41 are shown in Fig 6 and Fig 7 respectively. From these figures, we observe that the high cumulative risk for contingencies 11 and 41 are due to the high composite risk over a long period of time rather than a few high-risk instances. Hence, we need to identify maintenance tasks to reduce the high risk caused by these contingencies. Suppose the transmission component maintenance tasks have been found to reduce the two high-risk contingencies taking into account the component conditions. The budget constraint is $70000. The final maintenance schedule is shown in Table 2. The total risk reduction is 51.73. We reschedule the maintenance with B&B algorithm. The results are listed in Tables 3 and 4. The total risk reduction is 52.60.

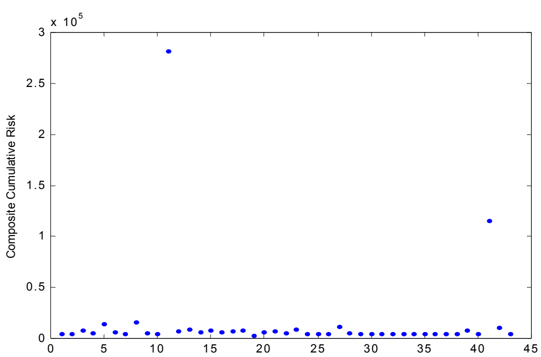

Fig. 5: Composite cumulative risk of each branch contingency

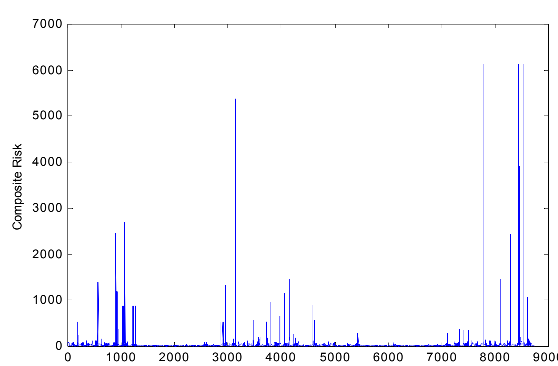

Fig. 6: Yearly composite risk for branch contingency 11

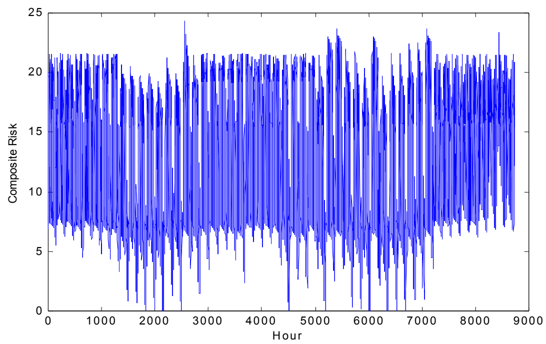

Fig. 7: Yearly composite risk for branch contingency 41

Maint. ID	Component ID	Cost ($)	StartTime-EndTime (hour)	CRR
CM0012	PR1006	1000	1-72	4.357
CM0010	CB0602	5000	73-180	6.514
CM0011	CB1002	5000	181-288	6.407
CM0009	LN061001	12000	1500-1739	0.065
CM0004	PR2521	1000	289-360	0.064
CM0008	PR2621	1000	361-432	0.185
CM0003	CB2102	5000	433-540	0.094
CM0002	CB1509	5000	541-648	0.093
CM0006	CB1504	5000	649-756	0.091
CM0007	CB2103	5000	757-864	0.029
CM0001	LN152101	12000	865-1104	0.029
CM0005	LN152102	12000	1105-1344	1.676
Total		69000		19.60

Table 2: Transmission maintenance schedule

We observe that the B&B results are better than the heuristic's for unit projects, but not substantially different for transmission projects. Altogether, the CRR improves from 51.73 to 52.60. Finally, the relative advantage of using the B&B approach should be more pronounced given a more restrictive budget. As we can see, the transmission budget was sufficiently large so as to impose no constraint at all on the scheduling problem; the unit budget was nearly the same. The program's primary value is selecting projects given scarce resources; it should perform relatively better in this context.

Maint. ID	Unit ID	Start Time-End Time (hour)	Budget ($)	CRR
GM0001	Unit 1	1-336	106000	18.5201
GM0002	Unit 3	337-840	82840	3.5560
GM0003	Unit 9	841-1344	93000	6.0408
GM0004	Unit 14	4096-4767	112290	4.4909
GM0005	Unit 19	4912-5079	10000	0.1954
GM0006	Unit 20	5460-5627	10000	0.1954
Totals			414130	32.9986

Table 3: Unit maintenance schedule

Maint. ID	Component ID	Start Time-End Time (hour)	Budget ($)	CRR
CM0012	PR1006	1-72	1000	4.3572
CM0010	CB0602	73-180	5000	6.5142
CM0011	CB1002	181-288	5000	6.4073
CM0003	CB2102	289-396	5000	0.1883
CM0002	CB1509	397-504	5000	0.0957
CM0004	PR2521	505-576	1000	0.0628
CM0006	CB1504	577-684	5000	0.0937
CM0008	PR2621	685-756	1000	0.0615
CM0007	CB2103	757-864	5000	0.0915
CM0001	LN152101	865-1104	12000	0.0294
CM0005	LN152102	1105-1344	12000	0.0286
CM0009	LN061001	1500-1739	12000	1.6757
Totals			690000	19.6059

Table 4: Transmission component maintenance schedule

7. Conclusions and future work

We have made significant progress towards developing the Integrated Maintenance Selector and Scheduler so that it enables maintenance planners to account for the cumulative effect of risk associated with system security concerns such as overloads, low voltages, and voltage instabilities arising from component outages. We believe that this approach will provide the industry with a method of identifying the most effective way to expend maintenance resources.

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