Base Cases for Assessing Risk in Transmission System Planning

Dimitry Gorinevsky, *Mitek Analytics LLC*, Palo Alto, CA, dimitry@mitekan.com

Saahil Shenoy, *Mitek Analytics LLC*, Palo Alto, CA, saahil@mitekan.com

Feng Zhao, *ISO New England*, Holyoke, MA, fzhao@iso-ne.com

Xiaochuan Luo, *ISO New England*, Holyoke, MA, xluo@iso-ne.com

Tongxin Zheng, *ISO New England*, Holyoke, MA, tzheng@iso-ne.com

Eugene Litvinov, *ISO New England*, Holyoke, MA, elitvinov@iso-ne.com

***Abstract*—This paper discusses probabilistic methodology for Transmission System Planning. Recent NESCOE memo suggested that current transmission planning procedure at ISO-NE might create inconsistency within the region and between the development plans of various transmission owners. The proposed methodology establishes base cases and contingency testing as means for consistent probabilistic assessment of reliability for a proposed transmission system plan. The system stress is computed through consistent probabilistic modeling and the base cases established by systematically sampling corresponding probability distributions. The methodology is illustrated for a simplified two-zone model of the power system.**

***Index Terms*—contingencies, outages, planning, probabilistic, transmission, relaxation**

I. Introduction

Transmission planning requires that the system is designed to operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies. The North America Electric Reliability Corporation (NERC) Transmission Planning TPL Standards define a set of mandatory performance requirements for the planning [1]. Each Transmission Planner and Planning Coordinator perform annual assessment of their portion of the Bulk Electric System to identify system deficiencies and plan corrective actions or system upgrades to meet the performance requirements.

Existing methodologies for transmission system reliability planning, followed by Regional Transmission Operators (RTO) such as ISO New England (ISO-NE), are mostly based on deterministic approaches. The established approach is to find a set of base cases that covers all corners of the system state space and represents system conditions under “reasonable stress” [2]. Those base cases are then tested with credible contingencies for transmission criteria violations. Transmission update plans are then developed based on the revealed transmission violations. Since the system space is very large, a set of assumptions and guidelines on the topology, load levels, generation availabilities, and transfer conditions are used in establishing the base cases. For example, ISO-NE uses 90/10 summer peak load level for its control area, and generally takes two generation resources out of service in a local study area. For intermittent resources, five percent of nameplate is modeled for on-shore wind, twenty percent for off-shore wind, and twenty-six percent for the solar generation [3].

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These practices and guidelines are mostly based on engineering judgment, and the resulting base cases do not provide probability guarantees of transmission system risk. A key drawback of the existing approach is not considering probability and severity of system stress in establishing the base cases. It is possible that a less likely higher peak load in combination with a smaller loss of resource availability may result in a greater system stress than at the usually considered 90/10 load level with more resources unavailable. In addition, current transmission planning practice may create inconsistency within the region and between the development plans of various transmission owners. As noted in [2], addressing these issues requires to re-assess base case development in the transmission system planning process.

This paper proposes a probabilistic approach to establish the transmission planning base cases by systematically sampling the combined probability distributions of load level and generation unavailability. Different from the existing approaches, the proposed approach looks for the highest probability conditions that can over-stress the system.

The contributions of the paper are as follows.

First, system risk is formalized. The risk is the product of impact (system stress) and probability. The system stress is defined through the most probable outages that lead to transmission criteria violations for a given load level.

Second, the base cases are established as conditions that create the highest risk. This provides a consistent approach to base case selection when fully covering all conditions at given level of the probability might be infeasible.

Third, the paper develops an optimization technique to determine the worst risk with respect to both the probability and the impact of N-1 contingency on the transmission system.

Finally, the paper proposes a relaxation approach to finding specific generator failures that result in the base case outages.

The paper outline is as follows. Section 2 provides an overview of the proposed approach in a formal setting. Section 3 defines system stress by computing the smallest outage violating the transmission criteria. Section 4 establishes Base Cases following Section 3 stress definition. Finally, Section 5 presents computational results for example two-zone system.

II. Approach overview

This section presents a high level overview of the proposed approach in a more formal mathematical setting. It introduces the problems to be solved using the proposed approach.

A. Probabilistic Model of Load

Consider a service area with K zones connected by transmission lines. Power demand in zone k is assumed to be

$$D_k = a_k \cdot L, \tag{1}$$

where total system load L is considered as random variable. Constant zonal load factors a_k are such that

$$\sum_{k=1}^{K} a_k = 1 \tag{2}$$

In what follows, we assume that random variable L has distribution with survival function $F(x) = \mathbf{P}(L \geq x)$ that is known. For given load, the risk of transmission criteria violations can be defined as Stress$\times$Probability, $S(L) \times F(L)$, where $S(L)$ is system stress for given load level and $F(L)$ gives the probability of the load being at that level or higher. Computing stress $S(L)$ requires probabilistic modeling of outage that is discussed next.

B. Probabilistic Model of Outage

Assume that total system load L, and zonal demands D_k in (1) are given. Zone k has generator capacities described by vector H_k with components $H_{k,i}$. Consider generators outage vector O_k with components $O_{k,i}$ If generator i in zone k is available, then $O_{k,i} = 0$. In case of the generator outage, $O_{k,i} = H_{k,i}$, where $H_{k,i}$ is the generator capacity for generator i.

Assuming the outages in different zones are independent, the probabilities of outages in the zones exceeding given levels Q_k can be computed as

$$R(Q) = \prod_k P_k(Q_k) \tag{3}$$

$$P_k(Q_k) = \mathbf{P}\left(\sum_i O_{k,i} \geq Q_k\right) \tag{4}$$

The survival functions $P_k(Q_k)$ in (3)–(4) are monotonically non-increasing functions of their arguments Q_k. As discussed further in the paper, these functions can be computed from GADS data using the convolution approach, see [4].

C. Evaluating System Stress

Stress $S(L)$ is defined as a minimum level of zonal outages (maximum zonal outage probability) such that exceeding that level is guaranteed to cause transmission criteria violation.

Consider zonal outage magnitude vector Q with components Q_k in (4). For given load L and outage Q, possible transmission criteria violation can be found by checking all N-1 contingencies. Each contingency corresponds to one of the transmission lines being down. If the load cannot be balanced for at least one of the contingencies, then transmission criteria violation index $V(Q; L) = 1$. If there is no violation, then $V(Q; L) = 0$.

Finding system stress level can be then formulated as the following optimization problem.

$$S(L) = \arg\min_Q R(Q), \tag{5}$$

$$\text{subject to } Q \in \mathcal{F}(L), \tag{6}$$

where outage probability $R(Q)$ is given by (3)–(4) and feasible domain $F(L)$ is defined as the set of all zonal outage power vectors Q such that $V(Q; L) = 0$.

Solving problem (5) for given load L gives the outage level vector $Q_*(L)$ and the stress $S(L) = R(Q_*(L))$ as the probability of exceeding these levels.

Next section discusses in some detail exact mathematical formulation and solution of problem (5) and computation of the stress $S(L)$.

D. Worst Case Risk

Assume that load probability distribution and, hence, $F(L)$ are known. Risk can be computed as $S(L) \cdot F(L)$ on a grid of values of L using (5)-(6). This allows to find load L_* that presents the worst case (maximum) risk $S(L) \cdot F(L)$ of transmission criteria violation and corresponding worst case stress $S(L_*)$.

In practice, risk $S(L) \cdot F(L)$ is usually a unimodal functions. To understand this, note that for small loads survival function is bounded, $F(L) \leq 1$, and stress $S(L)$ is small. For large loads, function $F(L)$ decays, while stress $S(L)$ increases.

III. Establishing Base Cases

The proposed approach is to generate and analyze base cases that cause maximum stress at load level L_* representing maximum risk of transmission criteria violation. This section introduces the method. Some examples are discussed in the next section.

A. Generation Dispatch

Transmission criteria violation can be checked by formulating and solving a Security Constraint Economic Dispatch (SCED) problem in the DC power flow setting.

Fixed problem parameters include total generation capacities C_k in the K service zones and flow capacities T_m in M transmission lines connecting the zones. These parameters are aggregated into vectors $C \in \Re^K$ with components C_k and $T \in \Re^M$ with components T_m. The SCED problem assumes zonal demand vector $D \in \Re^K$ with components D_k in (1) and generation outage vector $Q \in \Re^K$ with components Q_k are fixed problem parameters as well.

SCED is formulated as an optimization problem with decision variable vector $G \in \Re^K$. Components G_k of G are the dispatched generations for the zones. Given generations G and demands D, the flows through the transmission lines are given by $F = S(G - D)$, where $S \in \Re^{M,K}$ is the shift factors matrix. SCED problem looks for solution that works for each contingency

$$\text{minimize}_G \;\; \gamma(G) \tag{7}$$
$$\text{subject to } \mathbf{1}^T(G-D)=0, \tag{8}$$
$$0 \le G \le C-Q, \tag{9}$$
$$|U(G-D)| \le T, \tag{10}$$
$$|U_n(G-D)| \le T_n, \;\; (n=1,...,N), \tag{11}$$

where the inequalities involving vectors are applied component-wise and $\gamma(G)$ is a scalar valued cost of the generation dispatch. Equality constraint (8) describes balance between system-wide power generation and demand. Inequality constraint (9) describes power output limitations for generators. The ability to withstand all 'N-1' contingencies is described by (11), where T_n is the transmission capacity vector and U_n is the shift factors matrix corresponding to the n-th contingency. Vector T_n is the transmission capacity vector under the n-th contingency.

B. System Stress

Transmission criteria violation is defined by feasibility set $\mathcal{F}(L)$ of problem (7)–(11), where L enters the problem through zonal demands D in (1). If the problem is infeasible, transmission criteria are violated. Otherwise, if the problem is feasible, there is no violation. The feasibility depends on linear constraints (8)—(11), which define set $\mathcal{F}(L)$, and does not depend on cost function $\gamma(\cdot)$ in (7).

Computing stress $S(L)$ in accordance with definition (5)–(6) can be done by solving the following problem

$$S(L) \;\; = \;\; \min_{Q,G} \; R(Q), \tag{12}$$
$$\text{subject to } \mathbf{1}^T(G-D)=0, \tag{13}$$
$$0 \le G \le C-Q, \tag{14}$$
$$|U(G-D)| \le T, \tag{15}$$
$$|U_n(G-D)| \le T_n, \;\; (n=1,...,N), \tag{16}$$

where $R(Q)$ is given by (3)–(4).

We call problem (12)–(16) of computing system stress $S(L)$ the Critical Outage Magnitude Problem (COMP). Its solution is the critical outage Q_*. This is the minimal (in the sense of probability $R(Q)$ in (3)) outage guaranteed to make SCED problem (7)–(11) infeasible and, thus, transmission criteria violated.

C. Solving COMP

For solving COMP, it is convenient computationally to deal with the outage magnitude defined through a logarithm of the outage probability $R(Q)$ in (3) as

$$M(Q) = -\log R(Q) \tag{17}$$

Outage metrics $M(Q)$ (17) has the meaning of the negative log-likelihood, which is commonly used in Bayesian analysis. By using (3), we get

$$M(Q) = -\sum_k \log P_k(Q_k) \tag{18}$$

It can be convenient to use alternative stress metrics

$$M^{(0)}(Q) = \gamma \sum_k Q_k \tag{19}$$

This can be considered as a special case for (18) where outage probability distributions are exponential distributions. Such model matches Garver's rule known in capacity planning. The rule implies that outage distributions have exponential tails.

Since (17) provides a monotonic one-to-one mapping between $M(Q)$ and $R(Q)$, the original COMP problem (12)–(16) can be replaced by the following problem

$$\text{maximize}_{Q,G} M(Q), \tag{20}$$
$$\text{subject to } \{Q,G\} \in \mathcal{G}(L), \tag{21}$$

where set $\mathcal{G}(L)$ is defined by constraints (8)–(11).

Although set $\mathcal{G}(L)$ is convex, problem (20)–(21) is generally nonconvex because of $M(Q)$ in (18). In practice, it can be efficiently solved using Sequential Linar Programming (SLP) approach. The initial step of the SLP is to solve problem (20)–(21) where $M(Q)$ is replaced by $M^{(0)}(Q)$ (19). Linear value function (19) and linear constraints (8)–(11) yield an LP problem that can solved efficiently. At step k of the SLP method, where $k > 1$, the value function is replaced by $M^{(k)}(Q) = g^{(k-1)} \cdot (Q - Q^{(k-1)})$, where $Q^{(k-1)}$ is the optimizer from the previous. Gradient vector $g^{(k-1)}$ is

$$g^{(k-1)} = \left[\frac{\partial M(Q)}{\partial Q_1}, \ldots, \frac{\partial M(Q)}{\partial Q_K}\right]_{Q=Q^{(k-1)}} \tag{22}$$

D. Outage probability distribution

The above formulation requires computing $R(Q)$ in (3). This, in turn, requires computing $P_k(Q_k)$ in (4), the survival functions of the probability distributions for $O_k = \sum_{i=1}^{J_k} O_{k,i}$. Bernoulli random variables $O_{k,i}$ in the sum take values $\{0,\; H_{k,i}\}$ with probabilities $\{1-p_{k,i},\; p_{k,i}\}$, respectively.

Computing the distribution can account for many combinations of outages O that have similar impacts. In general, the distribution is defined on 2^{J_k} states that are combinations (partial sums) of $H_{k,i}$ for different subsets of indexes $i = (1, \ldots, J_k)$, where J_k represents the number of generators in zone k. This creates computationally unmanageable combinatorial complexity.

The complexity becomes linear and the distribution can be computed easily in a special case where all $H_{k,i}/\Delta h$ are integers for some fixed Δh. In that case, distribution states are integer multipliers of Δh not exceeding $\sum_k H_{k,i}$. Distribution for a sum of two independent random variables X and Y defined on the same uniformly sampled real states can be computed as a convolution

$$\mathbf{P}(X+Y=z) = \sum_x \mathbf{P}(X=x) \cdot \mathbf{P}(Y=z-x). \tag{23}$$

The approach to approximate the probability distribution in (4) is to select a small enough Δh and approximate $H_{k,i}$ as an integer multiples Δh by rounding. The distribution of the sum can be then computed by convolving individual Bernoulli distributions on the discrete state space. This is a well known approach, e.g., see [4].

E. Base Cases

Solving COMP problem (20)–(21) yields an optimized vector Q_* with components that are generation capacity outages $Q_{*,k}$ for the zones. Establishing a base case requires finding which generator outages correspond to this loss of capacity.

Finding the outaged generators can be formulated as the following sampling problem. Given the total outage h, find vector d with binary components $d_i = \{0,\ 1\}$ such that

$$\sum_{i=1}^{J_k} H_i d_i \approx h. \tag{24}$$

If approached directly, the sampling problem has combinatorial complexity and is computationally hard. A relaxation formulation of problem (24) is proposed below. The formulation is related to compressive sensing, specifically, sparse decomposition problem.

Consider the problem of maximizing Bayesian likelihood for binary outage $d \in \{0,1\}^{J_k}$. Vector d is described by generalized Binomial distribution that is a product of Binomial probability distributions for each generator outage.

$$\mathbf{P}(d) = \prod_j p_j^{d_j} \cdot (1-p_j)^{1-d_j}, \tag{25}$$

where p_j is the outage probability for generator j and d_j are binary variables. Based on (25), the log-likelihood has the form

$$\log \mathbf{P}(d) = \sum_j w_j d_j + \sum_k \log(1-p_j), \tag{26}$$

where $w_j = -\log(p_j^{-1} - 1)$.

The relaxation approach replaces binary variables d_j with real variables x_j, where $0 \le x_i \le 1$. The relaxed problem maximizes log-likelihood (26) to achieve (24), i.e.,

$$\text{maximize}_x \sum_i w_i x_i, \tag{27}$$

$$\text{subject to } h \le \sum_i H_i x_i \le h + \Delta h, \tag{28}$$

$$0 \le x_i \le 1, \quad (i = 1, \ldots, J_k), \tag{29}$$

where x_i are decision variables, h is the outage, and Δh is outage sampling accuracy. The LP problem (27)–(29) can be solved efficiently to find x_i. If for all i we have $x_i = 0$ or $x_i = 1$, then $d = x$ is an exact solution of the original problem of maximizing log-likelihood (26) to achieve (24). Typically, all but one variables x_i in the optimal solution of (27)–(29) are either 0 or 1; one variable might have a fractional value between 0 and 1.

Optimized discrete solution in the vicinity of the relaxed solution, can be found using the following *polishing* approach. The fractional weight is rounded first to 0, then to 1. For each of these two cases, each one of the remaining bits is flipped to generate $J_k - 1$ potential solutions, where J_k is the number of decision variables in (29). The approach thus needs to check $2J_k - 2$ potential solutions and pick a feasible solution with the maximal objective function cost in (27).

For given zones capacities Q_* and system load L_*, the binary outages d_j of generators for each zone can be computed as described above. These outages provide the critical base case for checking transmission criteria violation.

IV. Example Two-Zone System

Figure 1 shows a two-zone system example. The two zones roughly model ISO-NE service area and have the total generation capacities of $C_1 = 9.75$GW and $C_2 = 25.77$GW. Three transmission lines with capacities $T_1 = 1.2$GW, $T_2 = 1.2$GW, and $T_3 = 0.55$GW, respectively, connect the zones.

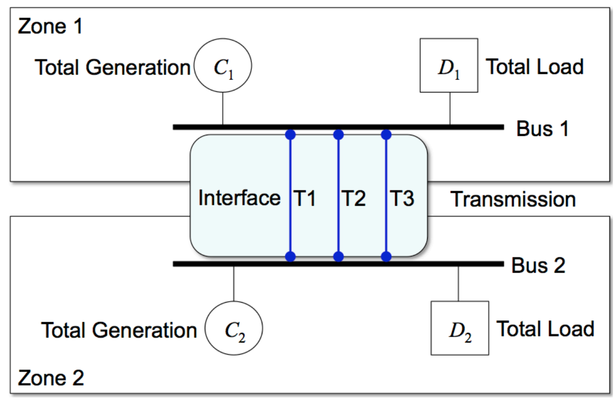

Fig. 1. Two-zone System Example.

The zonal demands D_1 and D_2 are defined by (1) where the load distribution factors are $a_1 = 0.2648$ and $a_2 = 0.7352$.

A. Load Probability Distribution

Computing risk in accordance with Subsection II-D requires knowledge of the survival function $F(L)$ for the load distribution. The load distribution was modeled based on historical data for the ISO-NE system demand for three recent years. The modeling is focused on distribution tail, which describes the peak load. The tail was modeled using logarithmic peaks-over-threshold (POT) data, i.e., the positive values of

$$V_j = \log(L_j / L_*), \tag{30}$$

where L_j is the system load data point and L_* is a fixed load value, such as $95/5$ load.

Random variable V in (30) was modeled using Extreme Value Theory (EVT), see [5]. Exponential distribution (Pareto distribution of the load tail) was fitted to the POT data (30). The model fit is illustrated by Quantile-Quantile (QQ) plot in Figure 2 that shows empirical quantiles of V vs. the quantiles of the fitted distribution $e^{-\theta V}$ for $\theta = 14.52$.

The final model factors in a forecast for 32% load increase. The tail part of the survival function for the load distribution has the form

$$F(L) = \mathbf{P}(D \ge L) = f_* \cdot e^{-\theta \log(L/L_*)} \tag{31}$$

where $f_* = 0.05$, $\theta = 14.52$, and $L_* = 21.34$GW are estimated from the historical data and the forecast.

Survival function (31) is illustrated in Figure 3 in the Loss of Load Hours (LOLH) format. The horizontal line shows LOLH

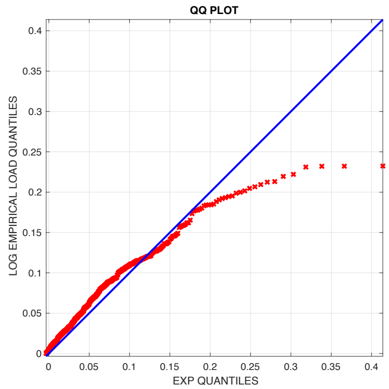

Fig. 2. QQ Plot for Log-load POT Data

= 2.4, which corresponds to the 1-in-10 requirement. The curve shows $F(L) \cdot 365 \cdot 24$, the expectation for the exceedance hours per year vs load level in GW.

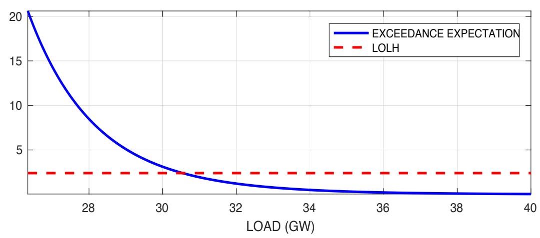

Fig. 3. Yearly Load Exceedance Expectation (Hours)

The developed model can be compared to the Garver's rule used by industry for Resource Adequacy Planning, e.g., see [6]. Assuming known probability R_* of exceeding past peak load P, Garver's rule states that exceedance of the load level L has the probability $R_* \cdot e^{-(L-P)/m}$. This implies exponential tail for the load distribution. In this work, Pareto tail model provided better fit to the load data. (The model gives exponential tail for the log-load).

B. Outage Probability Distribution

Example system Figure 1 has 73 generator units in Zone 1 and 233 units in Zone 2. Generator outage probability model is defined by capacities $H_{k,i}$ and EFORd $p_{k,i}$ probabilities. The capacities range from 10MW to 1250MW. The outage probabilities range from 0.01 to 0.42.

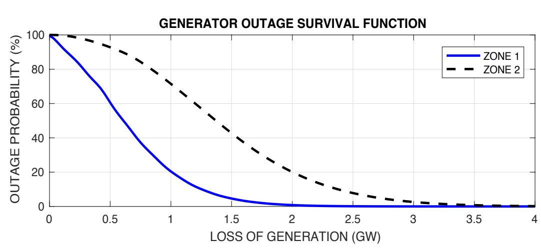

Fig. 4. Survival Functions for Outages in Two Zones.

Outage probability distributions (4) were estimated from this data. The capacities were rounded to the multiples of 30MW and the convolution approach in (23) was applied to estimate distributions in the sums of independent random variables, see [4]. Figure 4 shows computed survival functions $P_k(Q_k)$ for two zones $(k = 1, 2)$.

C. Computation of Stress

Consider formulation of SCED problem (7)–(11) for the example system in Figure 1. It is assumed that load L and, hence, the zonal demands D_k are fixed. Shift factors matrix U is derived assuming single interface with nominal capacity $T_1 + T_2 + T_3$. For three contingencies, the interface capacities change to $T_1 + T_2$ (Line 3 down) or $T_1 + T_3$ (Line 2 down) or $T_2 + T_3$ (Line 1 down), respectively.

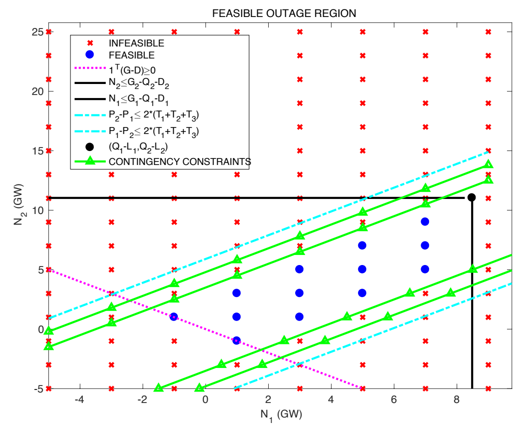

Fig. 5. LP Feasibility Example.

Figure 5 illustrates feasibility domain defined by linear inequality constraints (9)–(11) and generation constraint (8) in inequality form $\mathbf{1}^T(G - D) \geq 0$. The coordinates in Figure 5 are net injections $N_1 = G_1 - Q_1 - D_1$ and $N_2 = G_2 - Q_2 - D_2$ for the two zones. In the net injection variables, flow constraints appear as slanted lines. Net injections are bounded by $N_1 \leq C_1 - Q_1 - D_1$ (vertical line ending with dot) and $N_2 \leq C_2 - Q_2 - D_2$ (horizontal line ending with dot). Feasible points are shown as circular dots on the grid.

System stress $S(L)$ is computed by solving COMP (12)–(16). This is an extension of SCED problem (7)–(11) and maximizes the outage subject to the feasibility constraints.

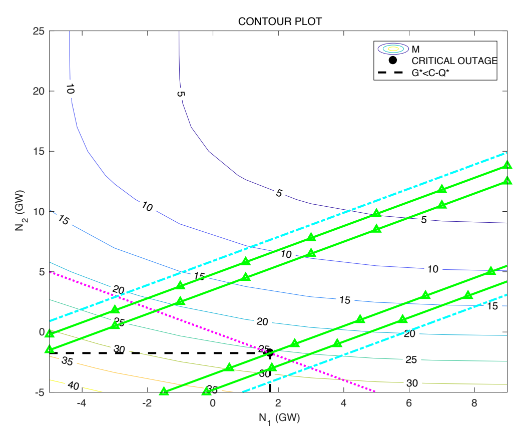

Fig. 6. COMP SLP Implementation

The SLP method (22) was used to solve the COMP problem for the example. It converged after one or two SLP iterations. Figure 6 has the same format as Figure 5 and shows solution as the intersection of two dotted lines corresponding to $Q_{*,1}$ and $Q_{*,2}$. The plotted isolines represent the value function $M(Q) = -\log P_1(Q_1) - \log P_2(Q_2)$, where $P_k(Q_k)$ are shown in Figure 4.

D. Risk Computation

Risk of transmission criteria violation was computed for a range of loads L sampled with 0.25GW interval. For each load L, stress $S(L)$ was computed by solving COMP problem as described in Subsection IV-C. A value of $F(L)$ was taken from the load distribution estimate shown in Figure 3. Risk of transmission criteria violation was computed as $S(L) \times R(L)$, see Subsection II-D for discussion. The computed risk is illustrated in Figure 7 for a range of L values.

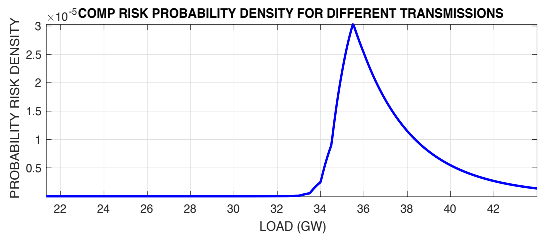

Fig. 7. Risk vs Load

The risk curve has a single maximum achieved at $L_* = 35.5$GW. The COMP solution for $L = L_*$ yields zonal outages $Q_{*,1} = 0.52$GW and $Q_{*,2} = 0$GW that produce stress $S(L_*)$.

E. Sampled Base Cases

To establish Base Cases for transmission system planning analysis, one needs to pick specific outaged generator units. These units in total should contribute generation outage Q_*, the COMP solution discussed in Subsection IV-D. The sampling problem of finding outaged units from Q_* is solved in Subsection III-E.

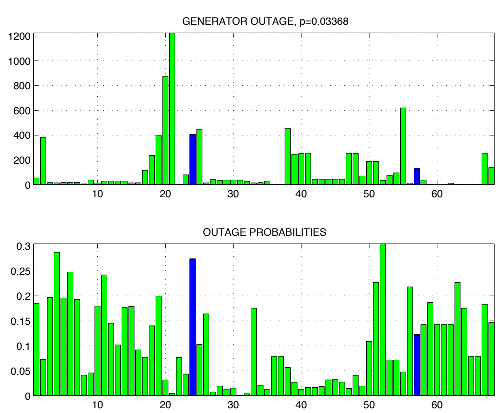

Fig. 8. Sampled Generator Outages for the Example

Outage sampling problem (27)–(29) was solved with accuracy $\Delta h = 30$MW. For Zone 1, COMP outage $Q_{*,1} = 0.52$GW; rounding to the nearest multiple of 30 MW yields $h = 510$MW. The solution obtained for Zone 1 is illustrated in Figure 8 and shows two outaged units: #24 and #57. For these units $H_{1,24} = 406.18$MW, $p_{1,24} = 0.2743$ and $H_{1,57} = 129.6$MW, $p_{1,57} = 0.1228$. Since $Q_{*,2} = 0$, the sampled solution and the base case have no outaged units in Zone 2.

V. Conclusion

Figure 9 provides an overview of the proposed probabilistic method for establishing base cases in transmission system reliability planning.

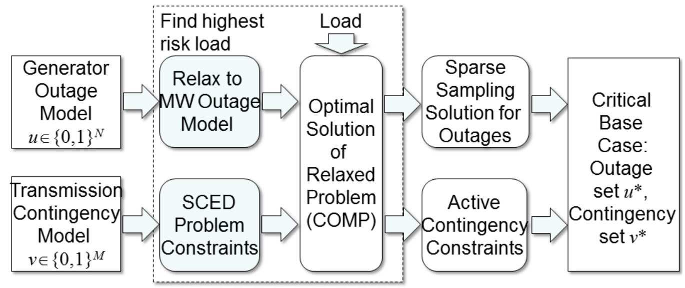

Fig. 9. Overview Diagram

The approach looks for the highest risk of transmission criteria violation as a product of the system stress and the peak load probability. The system stress is measured through maximal outage magnitude that makes the SCED problem infeasible. The stress optimization problem, COMP, is then formulated with linear SCED constraints that include transmission contingencies. Generator outages and their probability distributions in the COMP formulation are computed from the EFORd data using convolution. The proposed approach selects specific unit outages for the base case by solving the optimal outage sampling problem. While the existing base-case selection methods largely rely on engineering judgment, the proposed method is based on a rigorous formulation. The method produces a clearly defined risk level and specific base cases associated with that risk.

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