Engineering foundations for the determination of security costs

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Abstract

This paper characterizes system security by using distances to system operational limits (including voltage collapse limits, stability limits, line and transformer overloads, and generator limits). It uses the Point of Collapse method based on the singularity of the power flow Jacobian to define an Operational Limit Boundary in load demand space. Distances to this boundary are then translated into probabilistic measures of likelihood of system failure: Probability of Normal Status, Expected Demand Not Served, Expected Unserved Energy and, ultimately, Expected Outage Cost. Sensitivities of these measures to load and generation changes (important for operational decisions and real-time pricing) are also described. A numerical example is presented. Computational issues are discussed. **Keywords:** Security, adequacy, outage costs, loadability, voltage collapse, stability.

1 Introduction

This paper establishes foundations for the determination of the expected costs resulting from system outages. Outages refer to the inability of the system to supply part or all of the system load, not to equipment outages. The paper uses primarily static system security (system adequacy) concepts to separate regions of normal operation from regions where outages occur.

"Outage costs" are not normally in the vocabulary of power engineers. Systems have traditionally been operated on the basis of "economic dispatch" subject to "security constraints." The constraints typically assume that secure operation is of the utmost importance, overriding cost considerations. However, as systems become more strained and as the responsibility for system operation becomes increasingly diversified, knowledge of the limits of secure operation becomes more important. The very idea of a system that is either "secure" or "insecure" comes into question. Systems have varying degrees of security. Absolute security can never be attained.

All decisions about a system influence security to some

degree. Security is a function of configuration and operating condition. Often, security is expressed as a function of a single variable (such as total load or transfer capability between two areas). More likely, it is expressed as a constraint on this variable. This can be done because security is highly nonlinear. When the system is secure, most actions have negligible impact on security. However, when security is in jeopardy, many actions can have a significant effect on security. Thus, while at times security can be ignored, at other times security is most influential on decisions about the operation (and operating costs) of a system.

Landgren et al [23] and Brown [4] established interchange capability as a function of the capacity of certain lines, both before and after contingencies. Prediction of loadability is based on a linearization around a base case operating condition. These linearizations work reasonably well for the active power component, provided the resulting deviations are not too large and loadability is limited only by line flow restrictions.

Landgren and Anderson [24] extended loadability to consider tradeoffs among more than one transaction and more than one transmission line limit. Their work graphically illustrates security regions in systems. These ideas gave rise to the concept of maximum loadability [15] including generation limits.

In addition to these "static" limits, power engineers have been long aware of the importance of dynamics in setting limits on power transfer capabilities. Stability-induced limits are derived from numerous off-line transient stability studies. Results from these studies are codified as sets of operational limit rules for system operation. This is the basis for present-day dispatch practices within the industry.

A deterministic characterization of secure regions with contingencies was presented by Hnylicza et al. [16], taking into account both line and generation constraints. A formal characterization of security was presented by Galiana [14]. The incorporation of dynamics in the formation of security regions was described by Wu and Kaye [22,31].

Security is a probabilistic problem [12,30]. Many stochastic methods for system reliability [25] are applicable to the computation of system security.

Limits on generation capability and/or individual transmission lines are not the only limiting influences on security. Systems are reaching a more fundamental limit: the inability of the network to transmit power. The system reaches a "bifurcation" condition. One manifestation of bifurcation is steady state system instability. A second manifestation is voltage collapse [13].

When a single parameter in the system is varied, eventually some system limit is reached. This limit can be a transmission line or transformer overloading limit, a generation

91 WM 183-4 PWRs A paper recommended and approved by the IEEE Power System Engineering Committee of the IEEE Power Engineering Society for presentation at the IEEE/PES 1991 Winter Meeting, New York, New York, February 3-7, 1991. Manuscript submitted September 5, 1990; made available for printing January 22, 1991.

capacity limit, or a system collapse condition. The determination of the value of this parameter that results in the system reaching a limit gives better information about system security than linearization-based methods. The calculation of this limit is thus exceedingly important for security computations. There have been several attempts to calculate this ultimate transfer capability limit, particularly the limit associated with the singularity of the system Jacobian matrix [28]. One of the most successful methods is the Point of Collapse method in its various variants [3,1,29,27,17]. The Point of Collapse method has proven quite able to deal with realistic systems with numerous constraints, including HVDC transmission with full controls [2,5].

Sauer et al [26] present a modern view of loadability as the ability of the system to reach a point of collapse. It reconciles dynamic and static viewpoints, relating the stability Jacobian to the Power Flow Jacobian.

2 Nomenclature and Assumptions

It is only possible to talk about the cost of security in a statistical sense. At any time either the system is operational (no outage cost incurred) or it has sustained an outage. A priori quantification of outage costs can only be done as expected values. To characterize an outage fully it is also necessary to predict its duration, extent and location. Two approaches for the computation of the probability distribution of an outage are Monte-Carlo techniques and the theory of moments. Monte-Carlo techniques have been used with great success for system reliability calculations [18,19,25]. Monte-Carlo techniques can characterize arbitrary outage probability distribution functions (provided sufficient simulations are performed). However, Monte-Carlo methods can be expensive and they make it difficult to compute "incremental measures."

Direct computation of complex probability distributions based on the theory of moments has been used by Jorgensen [20], and promises an efficient way for the determination of probability distributions for system outages.

Real systems are subject to constant change: slow changes (load increase or decrease); and rapid changes (component outages). Without change, the concept of security is moot. The nomenclature adopted is: slow changes result in changes in system *conditions*, while discrete changes that alter the system result in different *configurations*. System conditions are assumed to vary independently of configuration, and vice-versa. This is not exactly true: for example, heavily loaded components are more likely to fail.

Each configuration has a given probability of occurring over time. Actual system conditions may be different than expected hours or a day in advance. Differences may be either uncorrelated or correlated. Correlated variations in bus demands are closer to reality, particularly for peak loads which are often quite weather sensitive. The main model used in the paper uses correlated load variations.

3 The Operational Limit Boundary

The Operational Limit Boundary (OLB) is a surface in bus (active and reactive) demand space that results in operational limits being attained. It can be used to measure the security of a given operating point (or demand condi-

Fig. 1: Surfaces that define the Operational Limit Boundary

tion) and to determine how power system operators could respond effectively should the security (adequacy) of a given operating point be undesirable.

A simple and direct computation of the expected value of the outage probability of a system is possible if the OLB is available, and if the probability distribution of system states can be assumed known on the same space where the OLB is defined. This permits the computation not only of the expected outage probability, but also of the incremental outage probability.

The OLB can be computed from the knowledge of:

- configuration (generators and lines in service),
- condition (demand levels at each bus),
- limits (transmission line and generator limits),
- system operating policies.

Figure 1 illustrates how the OLB is established for a given configuration for the case of a system with only two independent demands. The OLB concept generalizes to an arbitrary number of demands. The surfaces shown in Figure 1 denote demand levels that result in power system problems established by generation and transmission limits or by voltage collapse conditions. For a two-dimensional space, these limit surfaces are lines. For an n dimensional space of demands, these surfaces are manifolds of dimension $n - 1$. The composite OLB is the surface of demand levels that satisfy all of the individual boundary conditions. This composite OLB is the surface on which this paper focuses.

The operating policy also affects the location of the OLB—at least over some feasible range of options available to power system operators. For a given demand condition, power system operators have control over generation levels (active and reactive), unit commitment, and interchange levels with other utilities. Altering any of these variables affects the distance of that operating point from the OLB.

Since operating policies affect the OLB, it is possible to specify different OLBs depending upon the choice of operating policies. The simplest OLB is obtained using predetermined participation factors for all generators. A more

Fig. 2: Effect of operating policy on OLB

realistic OLB can be realized using a policy of economic dispatch. Both of these OLB's are likely to result in relatively "small" operational regions. In order to enlarge the size of the acceptable operating region it is possible to operate the system in a manner that sacrifices economy but results in a larger secure region. It is possible to use the DyLiaccio nomenclature [12] to define the following operational regions according to operating policy:

- Secure: operation within economic dispatch,
- Alert: operation with security constrained dispatch,
- Emergency: outages have occurred.

Figure 2 illustrates this characterization of the demand space, where the surface $y-y$ separates the regions of normal status—established by the economic dispatch policy—from the alert and emergency status regions. Surface $z-z$ is the surface beyond which the system is incapable of meeting total customer demand. The surface $z-z$ is the most relevant OLB when analyzing outage costs.

The OLB as used in this paper is based mainly on static measures. System dynamic considerations may make it impossible to attain operation too close to some regions of this boundary. Dynamic considerations can be used to define an OLB with a dynamic safety margin.

4 Distance to the OLB

Euclidean distances from the current operating point to the OLB give a simple indication of the possibility that a security problem might occur. The further the current operating point is from the OLB, the more secure the system is. Figure 3 illustrates the OLB in bus demand space.

Three possible distance measures to characterize the security of a given operating point are:

1. *Uncorrelated maximum available power* (MAP_i) is the distance from the operating point to the OLB when the demand at bus i is increased. In Figure 3, MAP_i

Fig. 3: Distance measures of proximity to the OLB

is the distance from a to b , and MAP_j is the distance from a to e .

2. *Correlated maximum available power* (CMAP) is the magnitude of the vector from the current operating point to the OLB surface along a line of simultaneous demand increases. In Figure 3, if the demands are perfectly correlated, then all of feasible demands lie along a line such as $f-f$, and the *CMAP* is the distance from a to c .
3. *Lowest maximum available power* (LMAP) is the minimum distance to the OLB from the operating point [21]. This distance is found by (1) determining the normal to the OLB that passes through the current operating point, and (2) determining the distance along the normal from the OLB to the current operating point.

Sensitivity of the distance measures to changes in demand or changes in generation level provides information about how decisions by customers or power system operators affect system security. These sensitivities can be found in the following manner.

Suppose g defines the OLB surface:

$$g(\lambda, \alpha) = 0 \quad \lambda \in R^n, \quad \alpha \in R^m$$

where λ represents load active or reactive power, and α represents generation active or reactive power. Let the line from an operating point λ^0 to the OLB be:

$$f(\lambda^0, \lambda) = 0$$

Linearization results in:

$$\begin{pmatrix} D_\lambda g \\ D_\lambda f \end{pmatrix} d\lambda + \begin{pmatrix} D_\alpha g & 0 \\ 0 & D_{\lambda^0} f \end{pmatrix} \begin{pmatrix} d\alpha \\ d\lambda^0 \end{pmatrix} = 0$$

From here:

$$d\lambda = - \begin{pmatrix} D_\lambda g \\ D_\lambda f \end{pmatrix}^{-1} \begin{pmatrix} D_\alpha g & 0 \\ 0 & D_{\lambda^0} f \end{pmatrix} \begin{pmatrix} d\alpha \\ d\lambda^0 \end{pmatrix}$$

where $(D_\lambda g, D_\alpha g)$ is the normal of g . This normal can be computed using the left eigenvector method [10]. A direct

Fig. 4: Contours of the Joint Probability Density Function of Bus Demands

method for finding the LMAP can be used [11]. The incremental MAP is then computed as:

$$dMAP = \|\lambda + d\lambda - \lambda^0 - d\lambda^0\| - \|\lambda - \lambda^0\|$$

Distance measures have an intuitive interpretation, but do not indicate likelihood, magnitude or economic significance of outages. The probabilistic measures described in the next section provide that information.

The discussion of proximity measures in this section used the OLB for one configuration. A weighted average of distance measures can be used to determine an aggregate measure of security over multiple configurations.

5 Probabilistic Measures

In addition to distance measures, there are several probabilistic measures of proximity to the OLB. These measures are of interest because of their applicability to operating and pricing policies.

Since demand is only known stochastically, there is a joint distribution of bus demands around an operating point which is at the mean of the distribution. Some demand combinations in the joint distribution fall below the OLB and normal operating status occurs. Other combinations fall beyond the OLB resulting in security problems and possible outages. Figure 4 illustrates possible distributions of bus demands.

The probabilistic measures include the following:

1. probability of normal operating status
2. expected demand not-served,
3. expected energy not-served, and
4. expected outage cost.

The ordering of these measures indicates an increasing amount of information required to make the computation. Measure 1 requires knowledge of the OLB and the joint

Fig. 5: Equivalent Areas of Normal Operating Status

probability density function of bus demands. Measure 2 requires knowledge of the *extent* of an outage (where extent denotes what buses and fraction of loads are involved in an outage). Measure 3 requires the additional knowledge of the *outage duration*. Finally, measure 4 requires the information used in computing measures 1-3 plus a knowledge of the *cost* of the outage to customers and the utility. Knowledge of sensitivity of measure 4 to load changes is useful for real-time pricing decisions [8,7].

5.1 Probability of Normal Status

Let P_i equal the active power demand at load bus i . P_i is a random variable defined by:

$$P_i = P_i^0 + u_i$$

where $E(u_i) = 0$. Thus $E(P_i) = P_i^0$. u_i is the difference between actual and expected demand for bus i at a specified time of day.

Assuming a two-load bus system, let the joint probability density function be specified by $f(u_i, u_j)$. Furthermore, assume that the probability of negative demand is zero. This assumption implies that any customer self-generation is low enough to insure positive net demand.

The OLB is defined by:

$$g(P_i, P_j) = 0$$

which implicitly defines either $P_i = g_i(P_j)$ or $P_j = g_j(P_i)$.

The probability that demands at buses i and j fall within the normal operating region where no outage occurs is given by

$$P^N = \int_{-P_j^0}^{P_j^m - P_j^0} \int_{-P_i^0}^{g_i(P_j^0 + u_j) - P_i^0} f(u_i, u_j) du_i du_j \quad (1)$$

Thus, the probability of a normal operating status is the "volume" of f inside the OLB. The outage probability is $1 - P^N$.

This equation can be simplified under the assumption that the deviations of bus demands from expected values are perfectly correlated. Under this assumption, the relationship between the deviations can be described as $c_i u_i = c_j u_j$.

Thus, the joint probability density function f can be expressed in terms of the probability density function of any bus demand. In Figure 5 the probability of a normal operating state is given equivalently by areas A , A_i , or A_j .

The point (P_i^B, P_j^B) is the intersection of line F with the OLB. If $f_i(u_i)$ is the probability density function for u_i , then the probability of a normal operating state is given by:

$$P^N = \int_{-P_i^o}^{u_i^B} f_i(u_i) du_i \quad (2)$$

where $u_i^B = P_i^B - P_i^o$.

As a consequence, the change in the probability of a normal operating state with respect to a change in expected demand P_i^o is given by:

$$\frac{\partial P^N}{\partial P_i^o} = f_i(u_i^B) \left[\frac{\partial P_i^B}{\partial P_i^o} - 1 \right] \quad (3)$$

where it is assumed that $f_i(-P_i^o) = 0$.

Of interest is the effect on the outage probability of changing the operating policy that determined the location of the OLB. When demands are perfectly correlated, the effect of changes in generation on P^N can be determined from:

$$\frac{\partial P^N}{\partial P_{gk}} = f_i(u_i^B) \left[\frac{\partial P_i^B}{\partial P_{gk}} \right] \quad (4)$$

where P_{gk} is the active power generation at bus k . A similar derivative can be determined for reactive power generation. The partial derivatives can be determined from elements of the normal vector to g .

5.2 Expectational Measures

The proximity measures of Expected Demand Not Served (EDNS), Expected Unserved Energy (EUE), and Expected Outage Cost (EOC) quantify the magnitude and economic significance of different levels of security. Their computation requires knowledge of the extent, duration, and cost of an outage.

Assume that all outages (1) have the same geographic extent and the amount of interrupted load is γ times total system demand, $0 \leq \gamma \leq 1$, (2) are of fixed duration (t_d), and (3) have a total outage cost given by C^{oc} . γ will depend upon P_i and P_j except for the system collapse in which case $\gamma = 1$. Again, the cause of the outage is demand rising beyond the OLB.

Crew and Kleindorfer [9] suggest that C^{oc} is composed of lost customer benefit plus the cost of interrupting customers (a "rationing" cost), less the operating cost savings because generation is reduced during an outage. Their formulation can be expanded to:

$$C^{oc} = \text{lost customer benefit} + \text{customer/utility restoration costs} - \text{operating cost savings}$$

Outage costs have a variable component that depends upon the amount of unserved energy. Caves et al. [6] note that studies of the functional relationship between outage costs and unserved energy have produced wide-ranging results.

Let $\Psi(P_i^o, P_j^o, u_i)$ represent either demand not served (DNS), unserved energy (UE), or outage cost (OC):

$$\Psi = \begin{cases} \text{DNS} &= \gamma \times \sum_{i \in S_D} P_i \\ \text{UE} &= \text{DNS} \times t_d \\ \text{OC} &= C^{oc}(\text{UE}) \end{cases}$$

where S_D is the set of load buses. Because demands are assumed to be perfectly correlated, expectational measures can be determined from:

$$E_\Psi = \int_{u_i^B}^{\infty} \Psi f_i(u_i) du_i \quad (5)$$

where $f_i(u_i)$ is the probability density function for u_i .

The sensitivity of the expectational measures to changes in demand at specified buses is:

$$\frac{\partial E_\Psi}{\partial P_i^o} = \int_{u_i^B}^{\infty} \frac{\partial \Psi}{\partial P_i^o} f_i(u_i) du_i - \Psi f_i(u_i^B) \left[\frac{\partial P_i^B}{\partial P_i^o} - 1 \right] \quad (6)$$

where Ψ is evaluated at (P_i^B, P_j^B) on the OLB boundary.

The interpretation of this equation when $\Psi = C^{oc}$ is that, for a change in P_i^o , expected outage costs change for two reasons: (1) the total outage cost changes and (2) the probability of an outage changes. Thus, a customer's decision to make an incremental increase in demand imposes a cost upon all other customers because the probability of an outage changes.

The sensitivity of the expectational measures to changes in generation variables (active or reactive) is:

$$\frac{\partial E_\Psi}{\partial P_{gk}} = -\Psi f_i(u_i^B) \frac{\partial P_i^B}{\partial P_{gk}} \quad (7)$$

In other words, re-scheduling generation may lower expected outage costs by changing the probability of an outage.

As in Section 4 on distance measures, the equations given in section 5 for the proximity measures apply to one configuration with its associated OLB. Probability weighting for different configurations yield probabilistic measures over multiple configurations.

6 Numerical Example

This section presents the results of determining proximity measures to a given OLB. Demands are assumed to be perfectly correlated.

Definitions and ideas are illustrated through a five-bus, two-machine system illustrated in Figure 6. The base case operating conditions listed in Table 1 gives two operating points: one operating point is considered as a "normal" operating point. The other operating point is deliberately close to the system OLB, and is considered an extreme operating point. Line parameters for the system are given in Table 2. Units are in per unit.

Under each operating condition, there are loads at buses 2, 4 and 5. P_2 and P_5 can vary arbitrarily within the Operational Limit Boundary, but reactive powers are fixed. The computed OLB is illustrated by a solid line in Figure 7. MAPs illustrate how much additional active power the system can supply to bus 2 and bus 5. This OLB is obtained from the system without constraints. Once constraints are imposed on the system, the OLB changes, along with the associated MAPs. Any given operating point may no longer

Fig. 6: Sample 5 bus system

Table 1: Base operating conditions

Bus	V	$P + jQ$	$P_g + jQ_g$
1	1.04∠0 (rad)	0	2.5687+j0.8863
2	0.9502∠-0.1665	1.4+j0.6	0
3	1.02∠-0.1304	0	1.1+j1.0342
4	0.9019∠-0.2594	0.7+j0.3	0
5	0.9475∠-0.1768	1.4+j0.4	0

Table 2: Extreme operating conditions

Bus	V	$P + jQ$	$P_g + jQ_g$
1	1.04∠0 (rad)	0	6.5427+j2.5989
2	0.8557∠-0.5207	3+j0.6	0
3	1.02∠-0.4892	0	1.1+j2.4533
4	0.8390∠-0.6043	0.7+j0.3	0
5	0.8496∠-0.4841	3+j0.4	0

Table 3: Line parameters of the system

Line	R(pu)	X(pu)
1 - 2	0.71400	0.17850
1 - 5	0.54313	0.13363
2 - 3	0.54313	0.13363
3 - 4	1.42800	0.35700
3 - 5	0.88507	0.22338
4 - 5	1.07098	0.26775

Table 4: Distance measures of system OLB

Distance Measure	Operating at (1.4, 1.4)	Operating at (3, 3)
MAP ₂	3.1132	0.9649
MAP ₅	3.2392	1.0363
CMAP	3.0703	0.8075
LMAP	3.0674	0.8062

Fig. 7: Actual OLB for 5 bus system, indicating the effect of limits on active generation power limits on the OLB

Fig. 8: Effect of configurations (line outages) on OLB

Table 5: Sensitivity of Distance measures at (3, 3).

P_i	$\frac{\partial MAP_2}{\partial P_i}$	$\frac{\partial MAP_5}{\partial P_i}$	$\frac{\partial CMAP}{\partial P_i}$	$\frac{\partial LMAP}{\partial P_i}$
P_2^o	-1.0000	-0.6078	-1.8585	-1.1490
P_{g3}	0.6819	0.6822	0.6486	0.6484
P_5^o	-0.5299	-1.0000	-1.1151	-1.9150

Fig. 9: Effect of line flow limits on OLB

Table 6: Probabilistic Measures of Proximity to the OLB

Operating point	$1 - P^N$	EDNS MW	EUE MWh	EOC 1000 \$
(3.0,3.0)	28.39%	258	64.5	645
(1.4,1.4)	$\approx 0\%$	≈ 0	≈ 0	≈ 0

be in the secure region. This means constraints may force system outages.

Figure 7 illustrates the computed OLB for the 5 bus system. In addition, it shows the effect of placing limits on active generation power on the OLB boundary. Figure 8 illustrates the original OLB plus the OLBs that result if different line outage cases are considered. Both operating points are within the original OLB, but only the "normal" operating point is within all three boundaries (and only marginally so). Figure 9 illustrates the effect of two different values of line flow limits on line 1-2 on the OLB. Again, the "normal" operating point is inside both limits, but the "extreme" operating point is not.

The various MAP measures for the system OLB at different operating point are given in Table 9. The sensitivities of these MAP measures both to demand at a bus and to generation re-scheduling are listed in Table 5. Under normal operating conditions, the effect on security is negligible.

Table 6 summarizes the probabilistic measures of proximity to the OLB. The probability density functions for the u_i at operating points (3,3) and (1.4,1.4) are $N(0,0.467)$ and $N(0,1)$ respectively. The extent of the outage is assumed

Table 7: Sensitivity of Probabilistic Measures to Changes in Injected Power

P_i pu	$-\frac{\partial P^N}{\partial P_i}$	$\frac{\partial \text{EDNS}}{\partial P_i}$	$\frac{\partial \text{EUE}}{\partial P_i}$ KWh/KW	$\frac{\partial \text{EOC}}{\partial P_i}$ \$/KW
P_2^o	0.1859	1.7418	0.4355	4.355
P_{g3}	-0.1628	-1.2767	-0.3192	-3.192
P_5^o	0.1530	1.4838	0.3710	3.710

to be total demand (that is, system collapse), and the presumed outage duration is 15 minutes. The outage cost is assumed to be \$10 per KWh of unserved energy. The probability of an outage, $1 - P^N$, is reported in Table 6. The results show that when the expected demands are close to the OLB, there is a high probability of collapse with its associated effect on EDNS, EUE and EOC.

Table 7 summarizes the sensitivity of the probabilistic measures to a change in injected power at various buses. Increasing demand at buses 2 and 5 increases outage probability, EDNS, EUE and EOC. Altering the operating policy by increasing active power generation at bus 3 improves all the security measures.

Conclusions

The concept of Point of Collapse is used to find "distances" to ultimate operational limits in demand space. Distance and probability measures of proximity to operational limits provide system operators with useful information for secure operation of the power system. Use of the operational limit boundary also permits the calculation of total and incremental values for expected demand not served and expected outage costs. This framework is computationally efficient and is able to take into account any kind of system model or operational limit.

Acknowledgement

Support from the National Science Foundation under contract ECE89-8907391 is acknowledged. Also acknowledged is support from the Electric Power Research Institute under contract RP-4000-14 under the supervision of Dr. Rambabu Adapa. Thanks are due to Ian Dobson, Chris DeMarco, and Laurence Kirsch for valuable suggestions.

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