Stability-Constrained Optimal Power Flow

Deqiang Gan, *Member, IEEE*, Robert J. Thomas, *Fellow, IEEE*, and Ray D. Zimmerman, *Member, IEEE*

***Abstract*—Stability is an important constraint in power system operation. Often trial and error heuristics are used that can be costly and imprecise. A new methodology that eliminates the need for repeated simulation to determine a transiently secure operating point is presented. The theoretical development is straightfforward: dynamic equations are converted to numerically equivalent algebraic equations and then integrated into the standard OPF formulation. Implementation issues and simulation results are discussed in the context of a 162-bus system.**

***Index Terms*—Power System, Transient Stability, Optimal Power Flow, Numerical Computation.**

I. INTRODUCTION

THE cost of losing synchronous through a transient instability is extremely high in modern power systems. Consequently, utility engineers often perform a large number of stability studies in order to avoid the problem. Mathematically, transient stability is described by solutions of a set of differential-algebraic equations [1]–[3]. The current industry standard is to solve the swing equations via step-by-step integration (SBSI) methods. Since different operating points of a power system have different stability characteristics, transient stability can be maintained by searching for one that respects appropriate stability limits. Such a search using conventional methods has to be done by trial-and-error methods incorporating engineering experience and judgement. Recently, significant improvements in computer technology have encouraged the successful implementation of on-line dynamic security assessment programs [4]–[7]. These new programs greatly improve the ability of stability monitoring, also indicate a trivial yet important issue: trial-and-error methods are not suitable for automated on-line computation.

The disadvantage of SBSI has been recognized since the earlier stages of computer application in power systems. This encouraged extensive investigations into energy function methods [8]–[11]. These methods have their roots in Lyapunov stability theory and they are able to provide a quantitative stability margin. With the stability margin in hand, the change in direction of an operating point can be derived [12]–[14]. Possibly for the same reason, research on pattern recognition and its variant, artificial neural networks, has also been rather active in the past two decades. Although these methods do not produce an explicit stability margin, they do provide for a simple mapping between controllable generation dispatch and indices such as an energy margin, rotor angles, etc. The simple mapping information can in turn be used in a preventive control formulation [15]. Other attempts to solve this preventive control problem can be found in, for example, references [4], [5], [16], [17]–[30].

In reality the stability problem appears to be an OPF-like problem, in which stability can be viewed as a constraint in addition to the normal OPF voltage and thermal constraints. Discussions on the possibility of including stability constraints into standard OPF formulations can be found in [19], [21], [22]. It is well-understood that voltage and thermal constraints be modeled via *algebraic* equations or inequalities [19]–[21]. It is, however, an open question as to how to include stability constraints since stability is a dynamic concept and *differential* equations are involved. We note that attempts based on either energy function method or pattern recognition have been pursued [12]–[15].

We also note that the emergence of competitive power markets creates the need for a stability-constrained OPF because the traditional trial and error method can produce a discrimination among market players in stressed power systems [23]. As reported in [24], "the past practice of maintaining reliability by following operating guidelines based on off-line stability studies is not satisfactory in a deregulated environment."

For the time being, there seems to be no general theory for computing stability limits [27]. In this paper, we develop an approach to address this problem. A similar approach using a significantly different dynamic metric and algorithms is discussed in [29]. We demonstrate our idea by developing a stability-constrained OPF framework. The methodology is built upon the state-of-the-art OPF and SBSI techniques. We found that, by converting the differential equations into numerically equivalent algebraic equations, standard nonlinear programming techniques can be applied to the problem. We demonstrate the technique on a 25-machine 162-bus system where stability constraints such as rotor angle limit, tie-line stability limits, and others can be conveniently controlled in the *same* way thermal limits are controlled in the context of an OPF solution. The stability- constrained OPF method is inevitably CPU-intensive. To relieve this problem, new implementation techniques are described.

II. A STABILITY-CONSTRAINED OPTIMAL POWER FLOW FORMULATION

A standard OPF problem can be formulated as follows[19]:

$$\text{Min} \quad f(P_g) \tag{1}$$

$$\text{S.T.} \quad P_g - P_L - P(V, \theta) = 0 \tag{2}$$

$$Q_g - Q_L - Q(V, \theta) = 0 \tag{3}$$

Manuscript received August 12, 1998; revised January 6, 1999.
The authors are with the School of Engineering Cornell University Ithaca, NY 14853 (e-mail: deqiang@ee.cornell.edu; rjT1@cornell.edu; rz10@cornell.edu).
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$$S(V, \theta) - S^M \leq 0 \tag{4}$$

$$V^m \leq V \leq V^M \tag{5}$$

$$P_g^m \leq P_g \leq P_g^M \tag{6}$$

$$Q_g^m \leq Q_g \leq Q_g^M \tag{7}$$

Where $f(\cdot)$ is a cost function; (2) and (3) are the active and reactive power flow equations, respectively; P_g is the vector of generator active power output with upper bound P_g^M and lower bound P_g^m; Q_g is the vector of reactive power output with upper bound Q_g^M and lower bound Q_g^m; P_L and Q_L are vectors of real and reactive power demand; $P(V, \theta)$ and $Q(V, \theta)$ are vectors of real and imaginary network injections, respectively; $S(V, \theta)$ is a vector of apparent power flowing across the transmission lines and S^M contains the thermal limits for those lines; V and θ are vectors of bus voltage magnitudes and angles with upper and lower limits V^m and V^M. Note that P_g, Q_g, V, and θ are the free variables in the problem.

Now, assume that the dynamics are governed by the so-called classical model in which the synchronous machine is characterized by a constant voltage E behind a transient reactance X'_d. For the sake of illustration, the load is modeled by a constant impedance. Note that more complicated models could be used in the same framework. We have the following "swing" equation [1]:

$$\frac{d_{\delta i}}{dt} = \omega_i \tag{8}$$

$$\begin{aligned} \frac{d_{\delta i}}{dt} &= \frac{\pi f_0}{2H_i} \left[P_{gi} - \frac{1}{X'_{di}} (E_i W_{xi} \sin \delta_i - E_i W_{yi} \cos \delta_i) \right] \\ &= D_i(P_{gi}, E_i, W_{xi}, W_{yi}, \delta_i, \omega_i) \end{aligned} \tag{9}$$

$$\begin{bmatrix} G & -B \\ B & G \end{bmatrix} \cdot \begin{bmatrix} W_x \\ W_y \end{bmatrix} = \begin{bmatrix} I_x \\ I_y \end{bmatrix} \tag{10}$$

where G and B contain the real and reactive part of the bus admittance matrix, respectively; W_x and W_y are vectors containing the real and imaginary part of the network (bus) voltages; f_0 is the nominal system frequency; H_i is the inertia of ith generator; ω_i and δ_i are the rotor speed and angle of ith generator. The ith entry of I_x and I_y is given by:

$$I_{xi} = \frac{E_i \sin \delta_i}{X'_d}, \quad I_{yi} = -\frac{E_i \cos \delta_i}{X'_d} \qquad \text{(generator buses)}$$
$$I_{xi} = 0, \quad I_{yi} = 0. \qquad \text{(nongenerator buses)}$$

We require that a solution of the stability-constrained OPF respect the following constraint for each i:

$$\overline{\delta}_i = \delta_i - \frac{\sum_{k=1}^{ng} H_k \delta_k}{\sum_{k=1}^{ng} H_k} \leq 100^\circ \tag{11}$$

where ng is the number of generators, and $\overline{\delta}_i$ is the rotor angle with respect to a center of inertia reference frame. Note that other physical constraints such as voltage dip can also be conveniently included here. In (11) we use rotor angle to indicate whether or not the system is stable. This criteria is consistent with industry practice and has been found by utility engineers to be acceptable. The reason is as follows. At first, we point out that there is no general method for measuring the stability region of dynamic system (8)–(10). Hence equation (11) is the only method available. Secondly, suppose the generators are approximately separated into two groups during the transient duration, then the well-know equal area criteria indicates that the relative rotor angle between the two groups of generators should always be smaller than in the extreme 180 degrees, otherwise the system is unstable. Thirdly, a real-world power system is always operated such that any generator rotor angle $\overline{\delta}_i$ will not be greater than a threshold (like 100 degrees). If a generator's rotor angle $\overline{\delta}_i$ is larger than such a threshold, the generator will be tripped off-line by out-of-step relay to protect it from being damaged [10].

A solution to a stability-constrained OPF would be a set of generator set-points that satisfy equations and inequalities (1)–(11) for a set of credible contingencies. Unfortunately, this nonlinear programming problem contains both *algebraic and differential* equation constraints. Existing optimization methods cannot deal with this kind of problem directly. In the next section, we propose a method to attack the problem.

III. Outline of the Idea

As mentioned in preceding text, it is relatively straightforward to include $n-1$ contingency constraints into an OPF since these constraints can be modeled *algebraically*. It is, however, an open question about how to include stability constraints. Obviously the key to solving the problem is in handling the differential equations. Here we convert the differential-algebraic equations to numerically equivalent algebraic equations using some appropriate rule. For our equations (8)–(10) and using the trapezoidal rule this yields:

$$\delta_i^{n+1} - \delta_i^n - \frac{h}{2}(\omega_i^{n+1} + \omega_i^n) = 0 \tag{12}$$

$$\omega_i^{n+1} - \omega_i^n - \frac{h}{2}(D_i^{n+1} + D_i^n) = 0 \tag{13}$$

$$GV_x^{n+1} - BV_y^{n+1} - I_x^{n+1} = 0 \tag{14}$$

$$BV_x^{n+1} + GV_y^{n+1} - I_y^{n+1} = 0$$
$$(n = 1, 2, \cdots, nend; \quad i = 1, 2, \cdots, ng) \qquad (15)$$

where h is the integration step length, n is the integration step counter, and $nend$ is the number of integration steps [28]. The stability constraints can thus be expressed as follows:

$$\delta_i^n - \frac{\sum_{k=1}^{ng} H_k \delta_k^n}{\sum_{k=1}^{ng} H_k} \le 100^\circ$$
$$(n = 1, 2, \cdots, nend \quad i = 1, 2, \cdots, ng) \qquad (16)$$

Note that we must set up the equations needed for computing initial values of rotor angle, and equations for computing parameters of the swing equations. It is trivial to show that:

$$\omega_i^1 = 0 \qquad (17)$$

$$E_i V_i \sin(\delta_i^1 - \theta_i) + P_{gi} X'_{di} = 0 \qquad (18)$$

$$E_i^2 - E_i V_i \cos(\delta_i^1 - \theta_i) - Q_{gi} X'_{di} = 0$$
$$(i = 1, 2, \cdots, ng) \qquad (19)$$

$$G_{load,\,i} = \frac{P_{Li}}{V_i^2} \qquad (20)$$

$$B_{load,\,i} = \frac{Q_{Li}}{V_i^2}$$
$$(i = 1, 2, \cdots, nb) \qquad (21)$$

Where $G_{load,\,i}$ and $B_{load,\,1}$ represent the real and imaginary part of load impedance, and nb is the number of buses. In summary, we obtain the following *algebraic nonlinear program (NP) problem*:

$$\begin{aligned} &\text{Min} \quad f(P_g) \\ &\text{S.T.} \quad (2)\text{–}(7) \\ &\qquad\quad (12)\text{–}(21) \end{aligned} \qquad (22)$$

This standard nonlinear programming problem can be solved using existing numerical methods. Indeed, the idea described in this section is surprisingly simple. In subsequent sections, we will develop a linear programming (LP) based computational procedure to solve this algebraic NP problem.

IV. Computational Issues

In this section, we outline the overall procedure of our method and discuss some of the computational complexities associated with it.

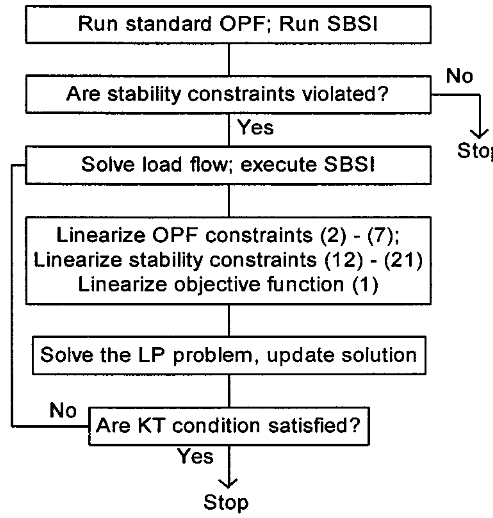

Fig. 1. Overall procedure for stability constrained OPF.

A. An Algorithm

A model algorithm that has been tested on several power systems is outlined in Fig. 1. We developed the model algorithm based on the successive linear programming method [22] with two additions: incorporation of stability constraints and a new constraint relaxation technique (the constraint relaxation technique described in [22] is also implemented in our code).

In what follows we explain the procedure described in Fig. 1. Since stability constraints are typically not binding, it is only prudent to begin by solving a standard OPF to start and to check to see if the solution of the standard OPF respects stability constraints. If the solution does, this solution is also the final solution of stability constrained OPF. If the solution does not respect stability constraints, then a complete stability constrained OPF must be solved.

The KT condition in Fig. 1 stands for the Kuhn–Tucker optimality condition associated with *the algebraic NP problem*. Inside the main loop, load flow and dynamic swing equations should be solved simultaneously. Based on our computational experience, this seems to be overly cautious. So in our prototype code, we solve load flow and swing equations sequentially. Our experience also indicates that the integration method and the step-size used in SBSI and that in the algebraic NP problem should be consistent. Otherwise, the algorithm may not converge.

Linearizing the objective function and constraints is trivial. Techniques for reducing CPU demand are thus discussed in the next section.

B. Computational Complexity

The algebraic NP problem (22) contains a very large number of constraints. We offer some observations that could lead to practical solutions. We start our discussion by making a comparison between steady-state security constrained OPF and dynamic-security constrained OPF. As an example assume:

—There are 10 contingency constraints
—The integration step size is 0.1 second
—The integration period is 2 seconds

—There are 2 network switches (the point in time where the fault is applied and cleared)

Note that each integration step imposes one set of constraints, those are, equations (12)–(16), so each contingency imposes a set of 22 constraints (2/0.1+2 constraints). Thus for this stability-constrained OPF, roughly 220 constraints need to be appended to standard OPF (l) to (7). For steady-state security constrained OPF, 10 constraints would need to be appended to standard OPF (l) to (7). This analysis is however overly simplistic because of the following reasons.

First, the number of binding constraints for dynamic security is typically smaller than that for steady-state security. In perhaps any power system, the number of binding stability constraints is normally very small, say in the order of 5 or less.

Second, the data structure of nonlinear programming problem (22) fulfills the requirement of successful application of the customized LP-based OPF algorithm reported in [22]. The major computational burden in the LP-based OPF algorithm is to repeatedly solve the so-called primal and dual equations $Bx = b$ and $B^T\lambda = f$. To solve the primal equations (the technique for dual equations is similar), write $Bx = b$ as follows:

$$\begin{bmatrix} B_{11} & B_{12} \\ B_{21} & B_{22} \end{bmatrix} \begin{bmatrix} x_1 \\ x_2 \end{bmatrix} = \begin{bmatrix} b_1 \\ b_2 \end{bmatrix} \tag{23}$$

Where sub-matrices B_{11} and B_{12} correspond to linear load flow equations linearized from (2)–(3). They are constant during the search of optimal basis. The solution of the primal equations is given by:

$$x_i = B_{11}^{-1}(b_1 - B_{12}x_2) \tag{24}$$

$$[B_{22} - (B_{21} \cdot B_{11}^{-1}) \cdot B_{12}] \cdot x_2 = b_2 - (B_{21} \cdot B_{11}^{-1}) \cdot b_1 \tag{25}$$

Since matrix $B11$ is constant during LP iteration, its factors are computed only once in the beginning of the process, and stored sparsely for the next iterations. During each LP iteration, one only need solve dense linear equations (25) for x_2, and perform forward/backward substitutions to compute x_1. From iteration to iteration, if the size of B_{22} is very small compared with that of basis matrix B, the above algorithm is extremely efficient. We point out that the data structure of nonlinear programming problem (22) meets this assumption, in addition, it is almost band-wise, and is very sparse.

Third, for most stability studies, we can apply the constraint relaxation technique explained below. Suppose the *maximum rotor angle at each integration step*, that is $\max(\overline{\delta}_i, i = 1, \cdots, ng)$, reaches maximum point at 0.4 second, then the constraints associated with those integration steps after (say) 0.6 second can be excluded from LP problem since they are not binding (Fig. 2).

Note that a full SBSI should always be performed to ensure that no stability constraint is violated. In other words, if any rotor angle violates the constraint after 0.6 second, these rotor angle constraints should be adaptively incorporated into the LP problem. Our method significantly reduces the size of LP problems. The results of simulation studies are provided in subsequent text to further illustrate the significance of this technique.

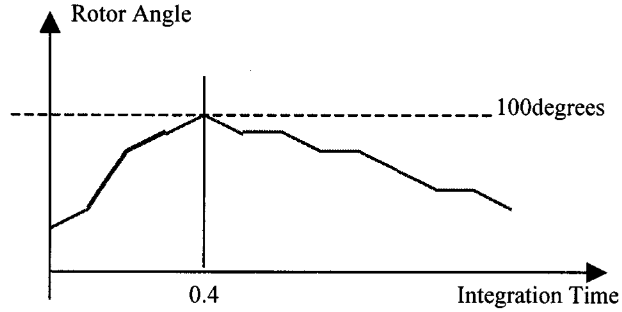

Fig. 2. Constraint relaxation for the stability constrained OPF.

V. An Extension

The integration-based method described in preceding sections also offers the basis of an analytical tool for other stability-related problems. We give some examples in this section.

Similar to standard OPF or steady-state security constrained OPF, the objective function of the stability constrained OPF can be defined as operating cost, transmission loss, as well as special objectives like the one given below:

$$\begin{aligned} &\text{Min} \quad \sum_i (P_{gi} - P_{gi}^0)^2 \\ &\text{S.T.} \quad (2)\text{–}(7) \\ &\qquad\quad (12)\text{–}(21) \end{aligned}$$

where P_g^0 represents the desired operating point (typically the previous one). The objective of this OPF is to find a secure operating point that is close to the desired operating point. Such a problem is known as preventive control or generation rescheduling [12], [16], [17].

Another example is to estimate the loadability of power systems subject to stability constraint [25]. The objective function and load flow constraints of this problem is defined as:

$$\begin{aligned} &\text{Max} \quad \lambda \\ &\text{S.T.} \quad P_g - \lambda P_L - P(V, \theta) = 0 \\ &\qquad\quad Q_g - \lambda Q_L - Q(V, \theta) = 0 \\ &\qquad\quad (4)\text{–}(7),\ (12)\text{–}(21) \end{aligned}$$

where scalar λ denotes a parameter associated with load increase.

Total Transfer Capability (TTC) or stability limit of tie line can possibly be computed by solving:

$$\begin{aligned} &\text{Max} \quad Interface\ Flow \\ &\text{S.T.} \quad (2)\text{–}(7) \\ &\qquad\quad (2)\text{–}(21) \end{aligned}$$

Note that once TTC is obtained, it is trivial to compute Available Transfer Capability (ATC) [24]. The interface flow can be of either point-to-point type or area-to-area type.

One of the advantages of our method is that it has little limitation on component modeling. Load can be flexibly expressed as any combination of constant impedance, constant current, and constant power. Generators can be modeled using a single-axis model, a two-axis model, or even a more detailed model [1].

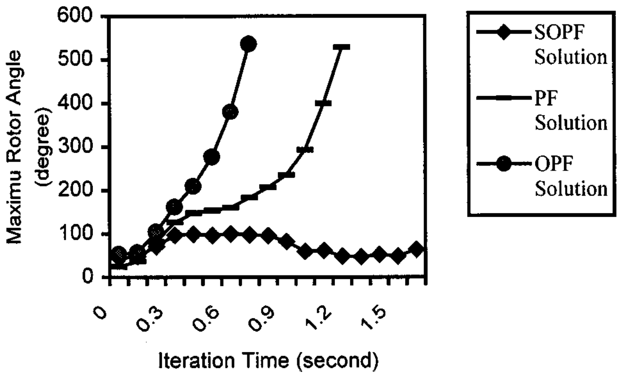

Fig. 3. Dynamic response of 162-bus system at three operating points.

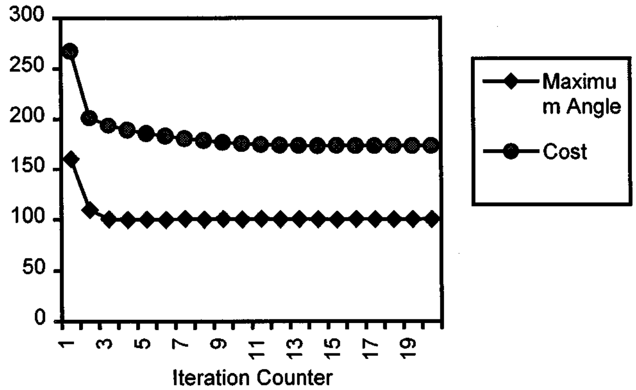

Fig. 4. Iteration process of stability constrained OPF.

Network changes such as three-phase-ground faults or the removal of transmission lines can also be modeled in a straightforward way.

VI. Numerical Examples

The integration-based method was implemented using the MATPOWER package [26], a MATLAB-based power system analysis toolbox that is freely available for download from the site at http://www.pserc.cornell.edu/matpower/. The prototype code has been tested on a 25-machine 162-bus system, 10-machine 39-bus system, and a 3-machine 9-bus system. The results of the 162-bus system are presented here.

A three-phase-to-ground fault is applied to bus 26, the fault is cleared 0.2 second later coupled with the removal of line 26–25. The integration is executed for 1.6 seconds. The power flow (PF) dispatch set-points were used as starting points to solve OPF and SOPF (though the results of OPF should be used as starting points to solve SOPF).

Fig. 3 illustrates the maximum rotor angles after the contingency when the operating point of the system is given by stability-constrained OPF (SOPF), PF, and OPF, respectively. It can be seen that the system does not survive after the contingency at operating points given by PF or OPF, it does at operating point given by SOPF.

The iteration process of the stability constrained OPF is shown in Fig. 4. The constraint relaxation technique illustrated in Fig. 2 has been implemented in our MATLAB code. It was found that the dynamics of system between 0.0 second to 0.6 second needs to be incorporated into LP problem, the dynamics of system beyond 0.6 does not contain a binding constraint thus is not included into the LP problem. As a result, the CPU saving is enormous.

VII. Conclusions

The objective of monitoring and ultimately controlling the stability of a power system is desirable. While the technology for stability simulation is rather stable now, little theoretical work has been done for computing stability limits precisely.

There is, however, an increasing need of solutions for this challenging problem. In this paper, we have developed a basis for one approach to this problem. The method naturally inherits the advantages SBSI has such as, it has little limitations on component modeling, it is robust, and it provides all system swing information. We demonstrated that, using this general methodology, for the first time the stability limits of power systems can be precisely and automatically estimated. We are hoping that the methodology can be further developed into a practical tool. This will require that it be efficiently implemented.

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Deqiang Gan (David) is a post-doctoral research associate at PSERC, School of Engineering, Cornell University. His research interests are power system stability and optimization.

Robert J. Thomas currently holds the position of Professor of Electrical Engineering at Cornell University. His current research interests are broadly in the areas related to the restructuring of the electric power business. He is the current Chair of the IEEE-USA Energy Policy Committee. He is a member of Tau Beta Pi, Eta Kappa Nu, Sigma Xi, ASEE and a Fellow of the IEEE. He is the current Director of PSerc, the NSF I/UCRC Power Systems Engineering Research Consortium.

Ray D. Zimmerman received a Ph.D. in electrical engineering from Cornell University in 199S. He is currently a research associate at Cornell in electrical engineering and experimental economics. His interests include restructuring of the electric utility industry and software tools for engineering research and education.