Overview of Key Stability Concepts Applied for Real-Time Operations

Savu C. Savulescu, *Senior Member, IEEE*

***Abstract*-- This paper discusses a number of background questions meant to set the stage when discussing the issue of real-time stability assessment and monitoring. Why at all real-time stability, to begin with? Which stability aspects are amenable to real-time assessment and monitoring? Could real-time stability assessment and monitoring have helped in the past to avoid blackouts? After a brief overview of frequent obstacles against real-time monitoring, e.g., extensive computation time, extensive modeling, complex result presentation, the paper addresses the intrinsic difficulty in quantifying the stability limit, or limits, and discusses a metric predicated on the concepts of steady-state stability reserve and safe operating margin.**

***Index Terms* -- open access transmission, maximum loadability, energy management systems, independent system operators.**

I. Introduction

IN the aftermath of the wave of blackouts that affected US, UK and mainland Europe utilities in recent years, new operating policies started to require system operators to compute stability limits "for the current and next-day operations processes to foresee whether the transmission loading progresses or is projected to progress beyond the operating reliability limit" [23]. This is far from being a trivial exercise primarily because, as opposed to computing thermal and voltage violations, which is straightforward and can be executed in real-time, detecting stability limits is a much more difficult.

There are various types of stability tools that may be used for a broad range of purposes, but in the context of system operations, which is essentially a real-time process, the primary concern is the risk of instability that may cause a widespread failure. The off-line assessment of the risk of system failure typically consists of executing detailed transient stability calculations on an extended collection of contingency scenarios for the purpose of determining whether all the post-contingency states are stable or not. When it comes to real-time, detecting the risk of blackout this way, unfortunately, is easier said than done. Due to a number of intrinsic difficulties, the scope of stability assessment in system operations reflects a compromise between the:

- Depth and extent of the stability analysis
- Level and granularity of the modeling details
- Need and/or ability to seamlessly integrate the stability computations with the SCADA/EMS platform
- Acceptable elapsed times for performing the calculations and presenting the results.

When it happens, instability develops almost instantly and leaves no time to react. Therefore, operating states that are vulnerable to instability must be *prevented* and, in order to quickly devise adequate corrective actions if and when needed, the risk of instability must be *predicted*. But since the operating conditions change continuously, the only way for the prediction to be timely and accurate is for the assessment to be performed in real-time and the distance to instability to be monitored continuously. This, in turn, rests on the ability to:

- Run fast stability calculations with real-time data that have been validated for completeness, accuracy and consistency, i.e., have been produced by a reliable and field-proven state estimator
- Complete the stability calculations within the time span of the real-time network analysis sequence, i.e., obtain and display the stability computation results before the next run of the state estimator
- Present the results in user-friendly formats that facilitate quick and reliable online decision-making.

There is more than one way to tackle the problem of real-time and online stability assessment, both because of the diversity of data and operational environments in existing SCADA/EMS systems and because stability analysis per se is extremely complex and can be addressed from various angles.

In the following we review some of the major approaches and briefly discuss their perceived strengths and limitations. Algorithmic and theoretical aspects are not addressed, but an extensive list of references is provided to assist the readers interested in further exploring the topics discussed herein.

II. In Search of the Stability Limits

A. Background

The evaluation of the operating reliability of transmission networks as required in system dispatching and operations

Paper PSE-09PSCE0657 to be presented at the "Real-Time Stability Assessment in Modern Power System Control Centers" Panel, IEEE Power Systems Conference & Exposition 2009 (IEEE PSCE'09), Seattle, WA, March 15-18, 2009

Based on Chapter 2 "Overview of Key Stability Concepts Applied for Real-Time Operations" by Savu C. Savulescu, in the book Real-Time Stability Assessment in Modern Power System Control Centers published by John Wiley & Sons and IEEE Press, 2009, © 2009 IEEE.

Savu C. Savulescu is with Energy Consulting International, Inc. New York, New York, e-mail scs@eciqs.com

planning is a complex undertaking. Depending upon the response time, mode of execution, and scope of analysis, the methods are referred to as static and, respectively, dynamic security assessment. Typical software tools are load-flow and stability programs.

An important goal of dynamic security assessment is to determine whether the system can withstand a set of major, yet credible, contingencies. This is the field of transient stability analysis. An equally important goal is to evaluate the risk of instability if the system approaches a dangerous state slowly as a result of:

- Small topology and/or load changes accompanied by slow bus voltage changes that may trigger a voltage collapse, and/or
- Gradual load increases that may eventually cause one or several generators to loose synchronism.

In the past, this was known as steady-state stability but today it is referred to as "voltage stability", as several authors have shown that "voltage stability" can be construed as "steady-state stability" [8] or "load stability" [10], [11].

Instability in a multi-area power system may also be triggered when attempting to transfer a large MW block between weakly interconnected areas, for example, when compensating load increases and/or generation outages in a system area by rising the generation elsewhere. In order to ensure that the grid would not get too close to its stability limits, prior to clearing such a transaction, one would first have to evaluate the maximum transfer capability across the "links", or transmission corridors, that interconnect the areas involved in such transactions.

There are other types of instability, e.g., units loosing synchronism due to self-oscillations. Unfortunately at the present time there is no unified methodology to handle all aspects of stability. Each form of instability requires appropriate models and adequate tools tailored to the physical phenomena under evaluation.

The problem becomes even more complex when the target is a vast interconnected system because of the sheer amount of data, the large computing times, and the technical skills needed to interpret the results. Even if computational speed is achieved and the stability calculations are performed in real-time, or, perhaps, online, i.e., with real-time input but slower than the real-time process, the end-users may have neither the time nor the background needed to assess the results.

These theoretical and practical difficulties can be overcome with approximate solution techniques that:

- Provide for quantifying the distance to instability
- Are fast enough so that they can be used in real-time
- Are demonstrably accurate and reliable
- Produce the output in formats that are easy to interpret and understand.

B. Are Stability Limits Quantifiable?

The industry has taken for granted concepts such as the Available Transfer Capability (ATC), Total Transfer Capability (TTC), Transmission Reliability Margin (TRM) and Capacity Benefit Margin (CBM), but only a handful of utilities are routinely performing real-time stability computations in dispatch centers.

According to NERC [20], the TTC is given by:

TTC = Min {Thermal Limit, Voltage Limit, Stability Limit}

Thermal limits, and, to some extent, voltage limits are well known and understood. Both the thermal and the voltage limits are predictable and can even be violated for short periods of time. But "stability limits" are not clearly defined. For example, how many "stability limits" are there and how are they defined and quantified? Can they be "violated"? And, if they can, by how much and for how long?

Conceptually, the "stability limit" is not unique. It is a function of the system state vector, i.e., for each new system state, there is a new stability limit, and it depends upon the trajectory followed to compute it. Simply stated, "stability limits" exist; are not fixed; change with the system's loading, voltages and topology; and depend upon the procedure used to stress the system conditions until instability has been reached. It is precisely this dynamic nature of the "stability limits" that makes it necessary to recompute and track them online.

However, the online evaluation of the stability limits does not guarantee that a blackout can be prevented. If the power system were operating with insufficient stability margin and a disturbance would push it beyond the stability limit in effect at that particular moment, instability would be unavoidable because the phenomena develop too quickly and make it virtually impossible to react in a timely manner. Therefore, in addition to a metric that could help quantify the distance between the current conditions and a hypothetical state where voltages may collapse and units may loose synchronism, the algorithm, or algorithms, that compute the risk of instability must be fast enough to perform the assessment immediately after a new state estimate has been calculated, so that the distance to instability can be monitored on a continuous basis.

Three different types of solution techniques have been implemented to date in power system control centers to address the needs for real-time stability assessment: transient stability; voltage stability; and steady-state stability.

III. TRANSIENT AND VOLTAGE STABILITY LIMITS

A. Transient Stability Limits

Sophisticated transient stability assessment tools are currently available to determine "whether a given condition is stable or unstable, but have not been efficient in quickly and automatically determining the stability limits, that is, how much a system, or part of a system, can be loaded before instability occurs" [21]. Since this statement was published in 1999, significant progress has been achieved in the industry and several successful online implementations of transient stability tools have been reported. The approaches that seem to have produced the most promising results are predicated on time domain simulations and Single Machine Equivalent methods.

Time domain transient stability analysis is both accurate and flexible [9] in terms of modeling detail and can handle:

- All the known types of power system components that correspond to active injections, such as generators, loads, Static VAr Compensators (SVC), FACTS devices, as well as the associated controls
- Any types of contingency, including three-phase and single-phase faults, as well as outages of multiple transmission and active power system components
- Any type of instability, such as first-swing or multi-swing, up-swing or back-swing, and plant or inter-area mode.

The complexity of the algorithms, coupled with the extent of the modeling details, renders their online implementation difficult but not impossible. Reference [12] describes time domain transient stability analysis programs that have been implemented on dedicated multi-computer architectures loosely integrated with existing SCADA/EMS systems. In all these cases, the stability applications use real-time data, produce results within time delays that are deemed acceptable by the users, and the overall process can be regarded as being performed "online".

On the other hand, the hybrid transient stability method called SIME (for SIngle-Machine Equivalent) opens the doors to accurate and fast transient stability analysis and, as shown by Pavella et al. in [9], is capable of real-time assessment and decision making. Even more importantly, this approach appears to make it possible to implement transient stability control.

The features and capabilities of the existing implementation of online transient stability vary from method to method, but they all seem to be hampered by:

- Computational burden, which somehow can be transcended by deploying multiple processor architectures
- Non-convergence of Newton-Raphson load-flow calculations near instability.

A major difficulty that is intrinsic to transient stability analysis regardless of the particular computational approach stems from the fact that it tells whether the reference base case is stable and remains stable for each one of the contingencies evaluated, but it neither determines a "transient" stability limit nor provides a safe margin where no contingency would cause instability.

In order to complete the search for stability limits, after both the base case and all the contingencies from the list were evaluated and if none of them caused transient instability, the system would have to be "stressed", e.g., by increasing the total MW generation, and at each step of "system stressing", the entire suite of transient stability calculations would have to be executed again. Conversely, if one or several contingencies simulated for the original base case would result in instability, the system conditions would have to be relaxed and the full suite of transient stability calculations repeated until a "safe" operating state has been found. Such an exhaustive search of the stability limit and safe operating margin is virtually impossible.

On the other hand, if the current base case corresponds to a maximum expected MW demand, including the wheeled power, if any, and if none of the contingencies evaluated caused transient instability, it can be inferred that the system is safe because, presumably, the probability of an event worse than those already simulated is very small.

B. Voltage Stability Limits

The realm of voltage stability, or "voltage security", assessment has been extensively addressed in the technical literature. A detailed discussion of "voltage stability" goes beyond the scope of this paper, but we need to briefly address this topic because, although voltage stability methods can successfully provide stability limits in the sense discussed earlier, this benefit can easily vanish if the so-called "voltage stability analysis" consists of running load-flows until they diverge or developing P-V curves without taking into account the dynamics of the machines.

1) Need to Represent the Generators

In 1975, V. A. Venikov et al. [16] asserted that under "certain conditions" the singularity of the standard load-flow Jacobian may indicate steady-state instability. As shown in [14], these "certain conditions" are: neglecting the generators' internal reactances and assuming that the generators are equipped with forced-action voltage controllers capable of maintaining the voltage constant at the machine terminals.

This is precisely the load-flow model. In load-flow computations, the internal reactances of the generators are not represented, and the voltages are maintained constant on the machine terminals or on the high-voltage side of the step-up transformers. If the generator reactances were included in the load-flow model, the PV buses would "move" to the internal generator nodes where the e.m.f. are applied, and since the e.m.f. are higher, or much higher, than 1.0 p.u., the Newton-Raphson calculations might diverge. In addition, it must be noted that although Newton-Raphson load-flow calculations diverge near instability, the divergence may be also due to other reasons and should not be used as a stability criterion.

According to Sauer and Pai [10], "for voltage collapse and voltage instability analysis, any conclusions based on the singularity of the load-flow Jacobian would apply only to the voltage behavior near maximum power transfer. Such analysis would not detect any voltage instabilities associated with synchronous machine characteristics and their controls" [10, pp. 1380]. In a subsequent publication [11], Sauer and Pai have shown the assumptions under which the standard load-flow Jacobian can be directly related to the system dynamic Jacobian are:

- Stator resistance of every machine is negligible
- Transient reactances of every machine are negligible
- Field and damper winding time constants for every machine are infinitely large
- Constant mechanical torque to the shaft of each generator

- Generator number one has infinite inertia
- All loads are constant power.

Sauer and Pai have further clarified the "special conditions" mentioned by Venikov and demonstrated that they actually imply the following:

- Stator resistance is negligible
- No damper windings or speed damping
- High gain and fast excitation systems so that all generator terminal voltages are constant
- Constant mechanical torque to the shaft of each generator
- All loads are constant power

Also regarding voltage stability, but in a different context, C. Barbier and J. P. Barret published in 1980 a seminal paper [2] that promoted the use of the maximum power transfer theorem to identify the point of voltage collapse at any given load bus. For the elementary case of a load represented by an impedance fed by a constant voltage source through a two-terminal system of impedance, Barbier and Barret showed that, when the admittance of the load increases, as new loads are added to the system, the active power delivered first increases, then passes through a maximum value, and finally decreases.

This result is known as the maximum power transfer theorem. In the Barbier and Barret model, the generators are shown via constant e.m.f. behind internal reactances, but this aspect went probably unnoticed, which perhaps explains why so many subsequent papers spread the idea that voltage collapse could be detected without representing the machines.

To set the record straight, this is what Barbier and Barret wrote about the representation of the generators [2, pp 681]: "*When the source substation can no longer hold its voltage constant, because it has reached its limit (rotor or stator current of a generating unit for example), there are two possibilities: either a further constant voltage point is found (such as e.m.f. behind the synchronous reactance of an alternator for operation of the latter at constant excitation …); or there is no constant voltage and the risk of voltage collapse is considerable. This would be the case, for example, of a system in which all the generating units are at the limit of armature current and in which the latter is maintained constant (at its maximum value) during taking over of load*".

The need to represent the synchronous machines rather than considering them as pure voltage sources has been emphasized by many other authors as well, e.g., Van Cutsem and Vournas who noticed that "besides some voltage droop under Automatic Voltage Regulator control, field and armature current limits must be obeyed. The former are imposed by Over Excitation Limiters and the latter by armature current limiters or (most often) by plant operators. These limits have a strong impact on maximum load power" [15].

A detailed discussion of this matter along with a proposal for an approximate representation of the generators that takes into account the behavior of the AVRs without actually representing them in detail has been provided by Molina and Cassano in the Section 1.2.3 of the Appendix A in [12].

2) Impact of the Load Model

Another basic assumption that is frequently accepted in the voltage stability literature is that the load can be approximated by an impedance. Ionescu and Ungureanu [6] analyzed the impact of load modeling and demonstrated that the voltage collapse process is affected by how we model the load as a function of voltage. If the loads are modeled as constant impedances, successive load increases cause the generated MW to increase until the point of maximum power transfer. Then, beyond that point, the total generated power starts getting smaller and dual power states (same power at different voltages) are obtained, hence the "nose" shape of the well known P-V curves. But dual states cannot happen in real life, and more realistic load models are needed so that the P-V graphs would stop at the point of instability.

Most of the aforementioned limitations and difficulties are resolved and eliminated if we revert to the classical framework of steady-state stability.

IV. Steady-State Stability Limits

A. General Considerations

The Steady-State Stability Limit (SSSL) of a power system is "a steady-state operating condition for which the power system is steady-state stable but for which an arbitrarily small change in any of the operating quantities in an unfavorable direction causes the power system to loose stability" [24]. An earlier definition refers to this concept as the "stability of the system under conditions of gradual or relatively slow changes in load" [1]. Voltage collapse, units getting out of synchronism, and instability caused by self-amplifying small-signal oscillations are all forms of steady-state instability.

Empirically, the risk of steady-state instability is associated with low real/reactive power reserves, low voltage levels, and large bus voltage variations for small load or generated power changes. Recurring "temporary faults" whereby breakers trip without apparent reason, i.e., are disconnected by protection without being able to identify the fault, might also be indicative of steady-state instability. Breaker trips can happen when loads increase due to "balancing rotors" of generators that operate near instability trip, and then get back in synchronism. In some cases, "the resynchronization happened after the rotor turned 360°, which, in turn, led to lower voltages" [4].

An interesting reading on this topic is [19]. Published in the aftermath of the August 14, 2003 blackout in the United States, EPRI's white paper begins with the statement "…based on available evidence in the FirstEnergy areas, the events of August 14, 2003 did not indicate a classical voltage collapse" [18, pp 6]. Yet subsequently the report presents data that document:

- Unexplained line trips
- Voltages "lower than expected"
- Low voltage alarms"

- The tripping of the 615 MW East Lake Unit 5 at 13:31:53 which "... dropped its reactive output from 393 MVAr to -1.8 MVAr when it exceed the maximum excitation limit"
- Voltages continuously decaying at the bus Star 345 kV, from 0.905 p.u. (14:10 pm) to 0.899 p.u. (15:32 pm) and then to 0.878 p.u. (15:55 pm)
- Numerous line and generator trips between 16:09 - 16:29 pm, each successive line trips causing further voltage degradation.

If these data are placed in the context of traditional steady-state stability, it can be inferred that on that fateful day the system was slowly approaching a state where, eventually, voltages would collapse and units would loose synchronism -- which actually did happen at approximately 16:29.

The phenomena encompassed by steady-state stability are extremely complex. Accordingly, specialized tools have been tailored to address natural stability vs. stability that is artificially maintained or enhanced by fast voltage controllers; local stability vs. global stability; aperiodic instability vs. instability caused by self-amplifying small-signal oscillations; and the stability of power transfers across transmission paths between system areas, which is actually a form of aperiodic instability.

The conventional method of the small oscillations for estimating the steady-state stability [1], [4], [14] consists of examining the eigenvalues of the linearized characteristic equation associated with the system of differential equations that describe the free transient processes after a small disturbance takes place in an automatically controlled power system. The necessary and sufficient condition for steady-state stability is that all the real parts of the eigenvalues be negative [14]. The approach is laborious and is replaced by determining relationships between the roots and the coefficients of the characteristic equation. Venikov refers to these relations as "steady-state stability criteria" and classifies them into algebraic (Routh-Hurwitz) and practical.

A necessary, but not sufficient, condition for steady-state stability is derived from the Hurwitz criterion by evaluating the sign of the last term of the characteristic equation, which is the dynamic Jacobian determinant D. A change of sign from positive to negative (all Hurwitz determinants are positive) with further loading of the system indicates aperiodic, or monotonic, instability. The instability in the form of self-oscillations, however, remains unrevealed by this method.

The "algebraic steady-state stability criteria" have been known for a long time and can form the basis for algorithms that search for the aperiodic steady-state stability limit by alternating the calculation of the dynamic Jacobian determinant with some procedure to stress the system until it becomes unstable. For the purpose of real-time stability assessment, the so-called "practical steady-state stability criteria" greatly simplify the calculations and, if applied in conjunction with an adequate system stressing procedure, allow computing the distance to instability, or "stability reserve" and evaluating the "security margin" quickly enough for being applicable in real-time.

B. Practical Steady-State Stability Criteria

Under certain conditions, the calculation of the dynamic Jacobian determinant can be replaced by evaluating one or several of the so-called "practical steady-state stability criteria", which: were developed by the Russian school of stability [14]; refer to aperiodic instability; cannot detect instability due to self-sustained oscillations; are derived from the condition D = 0; and are valid if:

- The generators are radially connected to a nodal point -- this is not generally true in actual networks but is always the case if the short-circuit currents transformation is applied to convert the power system network to a scheme of short-circuit admittances connected radially to a load bus that becomes the "nodal point" required for the practical criteria to be valid
- The system frequency is constant during the short period of time associated with the transient process
- One of the following assumptions can be made: (a) the voltage is constant at the nodal point, in which case the synchronizing power criterion $dP/d\delta$ is obtained; (b) the power balance can be maintained at the nodal point, which leads to the reactive power steady-state stability criterion $d\Delta Q/dV$.

The $d\Delta Q/dV$ criterion was found to be particularly attractive in conjunction with Paul Dimo's REI methodology and has been used since early 1960s to compute the "stability reserve", which is a metric for quantifying the distance to instability. Its mathematical proof is provided in Annex 1-1 of Chapter 1 in reference [12]. Further insight regarding this important tool for quickly evaluating the steady-state stability conditions of a power system is provided, along with a numerical illustration, in Section 3.2 of Appendix A in [12].

C. Distance to Instability. Security Margin

1) Steady-State Stability Reserve

Approaching the search for a stability limit from the steady-state stability perspective brings promising results. To begin with, the SSSL can be defined both system-wide and for individual buses. Then, the system-wide SSSL can be quantified as the maximum total MW system grid utilization, including both internal generation and tie-line imports, right before instability. On this basis, a metric that quantifies "how far from SSSL" is a given operating state has been known and used in Europe since 1950s [3], [4], and [5]. For example, the 1964 Special Report of the Group 32 of CIGRE states that "any network that meets the steady-state stability conditions can withstand dynamic perturbations and end in a stable operating state" [7].

2) Security Margin

A Transient Stability Limit (TSL) can also be thought to exist but, as opposed to SSSL, it is not quantifiable through a specific formula. However, intuition suggests that a "safe" system MW grid utilization, expressed as a fixed percentage of the SSSL and referred to as *security margin*, could be found such that, for any system state with a steady-state stability reserve higher than this value, no contingency, no matter how severe, would cause transient instability.

The knowledge of a "safe" amount of stability reserve, or security margin, such that transient instability would not occur, makes it possible to replace the otherwise unsolvable problem of computing the TSL with a relatively simple procedure:

- First: starting from a state estimate or solved load-flow, determine the steady-state stability reserve, i.e., the distance to SSSL
- Then: for the known (and fixed) x% security margin, determine the corresponding safe system MW loading below the SSSL.

Each system has its own security margin. For example, reference [5] recommended a 20% security margin for the Romanian power system as it was in the 1970s. Reference [17] describes the procedure used by ETESA, Panama, to validate the value of the security margin (15%) that is currently used in conjunction with its real-time stability assessment application.

V. Concluding remarks

This paper addressed various theoretical aspects of stability assessment in power system operations. As opposed to system planning, where the stability studies are concerned with postulated scenarios over long periods of time, the primary concern in operations is "whether the transmission loading progresses or is projected to progress beyond the operating reliability limit" [23]. This is consistent with the SCADA "supervisory control" function which entails monitoring the real-time values of the system frequency, tie-line interchanges, selected bus voltages, and so on, against their prescribed operational limits.

The concepts of steady-state stability reserve and security margin have been shown to provide a solid metric for quantifying the distance to the state where voltages may collapse and/or units may loose synchronism, and for approximating a safe operating limit where, given the current operating conditions and a dynamically selected set of major, yet credible contingencies, there is no risk of blackout.

The most successful real-time and online stability solutions implemented to date rely on one or several of the techniques identified in this paper but differ substantially in terms of: seamless vs. loose integration; continuous assessment vs. periodic checks; user interaction and presentation of results. These implementations are extensively described in [12].

VI. References

[1] Crary, S. B., 1945, Power System Stability, General Electric Series, Schenectady, New York, Copyright 1945, Third Printing October 1955

[2] Barbier, C., Barret, J.P., "An Analysis of Phenomena of Voltage Collapse on a Transmission System", RGE, special edition CIGRE, July 1980, pp. 3-21

[3] Dimo, Paul, "Etude de la Stabilité Statique et du Reglage de Tension", R.G.E., Paris, 1961, Vol. 70, 11, 552-556

[4] Dimo, Paul, Nodal Analysis of Power Systems, Abacus Press, Kent, England, 1975

[5] Dimo, P., Manolescu, G., Iordanesscu, I., Groza, L., Ionescu, S., Albert, H., Moraite, G., Ungureanu, B., Computation and design of electrical energy systems (Romanian edition), Editura Tehnica, 1971, Bucharest, Romania, pp. 200-201

[6] Ionescu, S., Ungureanu, B., "The Dual Power States and Voltage Collapse Phenomena", Rev. Roum. Sc. Tech., Série Elect. et Energ., Tome 26, No. 4, pp. 545-562

[7] Magnien, M., Rapport spécial du Groupe 32 Conception et Fonctionnement des Réseaux, Conférence Internationale des Grands Réseaux Electriques à Haute Tension, CIGRE Session 1964

[8] Navarro-Perez, R., Prada, R.B., "Voltage Collapse or Steady-State Stability Limit", in Proceedings of the International Seminar on Bulk Power System Voltage Phenomena II, pp. 75 - 84, (Edited by L. H. Fink, 1993)

[9] Pavella, M, Ruiz-Vega, D., Glavic, M., "SIME: A Comprehensive Approach to Transient Stability", in "Real Time Stability Assessment in Modern Power System Control Centers", IEEE Press & John Wiley, NY, 2008

[10] Sauer, W.P., Pai, M.A., "Power System Steady-State Stability and the Load-Flow Jacobian", IEEE Transactions in Power Systems 5 T-PWRS, 4, pp. 1374 – 1381, 1989

[11] Sauer, W.P., Pai, M.A., "Relationships between Power System Dynamic Equilibrium, Load-Flow, and Operating Point Stability", in Real Time Stability in Power Systems, pp. 1-30, Springer Verlag, Norwell, MA, 2006

[12] Savulescu, S.C., Real-Time Stability Assessment in Modern Power System Control Centers (Editor), John Wiley & Sons and IEEE Press, New York, New York, January, 2009

[13] Savulescu, S.C., "Fast Assessment of the Distance to Instability. Theory and Implementation", in Real Time Stability in Power Systems, pp. 31-64, Springer Verlag, Norwell, MA, 2006

[14] Van Cutsem, T., Vournas, C., "Emergency Monitoring and Corrective Control of Voltage Instability", in Real Time Stability in Power Systems, pp. 94-118, Springer Verlag, Norwell, MA, 2006

[15] Venikov, V.A. Transient Processes in Electrical Power Systems, Edited by V. A. Stroyev, English Translation, MIR Publishers, Moscow, 1977

[16] Venikov, V. A., Stroev, V. A., Idelchick, V. I., Tarasov, V. I., "Estimation of Electrical Power System Steady-State Stability", IEEE Trans. on PAS, vol. PAS-94, No. 3, May/June 1975, pp. 1034-1041

[17] Vergara, J. S., Thai, T.A., Cuong, N. D., Nam, N.T., Campeanu, H.S., Savulescu, S.C., "Accuracy Testing and Real-Time Implementation of Dimo's Stability Analysis Technique", in Real Time Stability in Power Systems, Springer Verlag, Norwell, MA

[18] Virmani, S., Vickovic, D., Savulescu, S.C, "Real-Time Calculation of Power System Loadability Limit", Paper No. 576 presented at the Powertech 2007 Conference, July 1-5, 2007, Lausanne, Switzerland

[19] ***** EPRI, "Factors Related to the Series of Outages on August 14, 2003", a White Paper, Product ID 1009317, November 20, 2003

[20] ***** NERC, "Available Transfer Capability Definitions and Determination", North American Electric Reliability Council, June 1996

[21] ***** IEEE PES, "Techniques for Power System Stability Search", A Special Publication of the Power System Dynamic Performance Committee of the IEEE PES, TP-138-0, 1999

[22] ***** IEEE PES Task Force on Terms and Definitions, "Proposed Terms and Definitions for Power System Stability", IEEE Trans. on PAS, vol. PAS-101, No. 7, July 1982

[23] ***** NERC, "Policy 9 - Reliability Coordinator Procedures", Version 2, Approved by Board of Trustees February 7, 2000

[24] ***** IEEE/CIGRE Joint Task Force on Stability Terms and Definitions, "Definition and Classification of Power System, Stability", IEEE Trans. on PAS, vol. 19, No. 3, August 2004, pp. 1387-1401

Savu C. Savulescu (M'1972, SM'1975) graduated in electrical engineering from the Polytechnic Institute of Bucharest, Romania, and obtained the degree of Doctor of Sciences (Ph.D.) from the Polytechnic School of Mons, Belgium. He is a Professional Engineer in the State of New York, USA, and holds a postdoctoral degree from the University of Sao Paulo, Brazil. He is with Energy Consulting International, Inc., a New York based corporation specializing in software, information systems and related applications for the utility industry. Dr. Savulescu is a Senior Member of IEEE.