Bulk Power System Dynamics and Control VII, August 19-24, 2007, Charleston, South Carolina, USA

The Role of Numerical Tools in Maintaining Reliability During Economic Transfers

An Illustration Using the NPCC Equivalent System Model

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Abstract In this paper we are concerned with the increased complexity facing operators when monitoring and scheduling available resources needed to serve customers without interruptions and at the reasonable costs. Historically, this task has been met by combining human expert knowledge about the specifics of the system with the results obtained by approximate numerical tools for near real-time analysis and assessment of system conditions. The emphasis in this paper is on demonstrating fundamental limits to relying on human decision making due to a highly combinatorial nature and complexity of managing reliability and economics of electricity services in today's nonlinear electric power network systems. This complexity calls for development of more accurate and quantifiable numerical methods for decision making in such systems. We illustrate the type of near-real time numerical tools essential for implementing such decisions. A comparison of the NPCC system utilization by means of current and future numerical tools is presented.

Keywords: Real Power Transfer Limits, Critical Contingencies, Voltage Optimization, Reactive Power Optimization, Preventive Scheduling, Corrective Scheduling, Real Power Dispatch, North American Electric Power Coordinating Council (NPCC), AC Optimal Power Flow (AC OPF).

I. Introduction

The US electric power grid is no longer being used under the conditions for which it was initially designed. For example, the T&D system design and operating procedures were conceived keeping a specific power flow pattern in mind. Planning for normal (nominal) operations had the major goal of meeting native load in each utility (control area), and planning for abnormal conditions at a regional level had the objectives of sharing resources among the control areas. More recently, these planning procedures have been undergoing major changes. Generation is built in an open-access manner often by the investors outside the control areas in which power plants are physically located. As the new power plants are being added by private investors, and some old utility-owned plants are being retired, and the interconnection is expected to be utilized as a single grid across several control areas, it is becoming increasingly complex to manage the system reliably. System operators familiar with their own control areas are only able to manage their own subsystems for the assumed conditions in the neighboring control areas. Managing the region as a whole according to the quantifiable criteria will require computer-aided near-real time monitoring and re-scheduling of available resources, as the human ability to manage complexity of this order is exceeded.

Related, similar computer-aided tools are important for the actual implementation of the reliability industry standards by the industry. The need for well-defined binding reliability criteria has been fully recognized in the recent Energy Policy Act by requiring the creation of an Electricity Reliability Organization (ERO) directly responsible for enforcing the reliability standards. As the industry adopts such standards, it is essential to also recognize that these standards could be enforced in a variety of non-unique ways, some relatively straightforward, but extremely costly, and the others more complex to implement but potentially much less costly. New software could play a major role in cost reduction.

This paper does not concern the very notion of reliability and efficiency performance metrics for the changing industry. It stresses, instead, that implementing/enforcing given reliability standards requires more quantifiable near-real time decisions for scheduling the available resources on behalf of the end users than in the past. We set forward a basic premise that, independent of the type of industry organization one is presented with, it is no longer possible to manage complex electric power networks based solely on preventive worst-case scenario studies. It is, instead, essential to continuously monitor system conditions and adjust in near-real-time available resources according to well-defined trade-offs, standards, and protocols. While the principles for such protocols are possible to design ahead of time, the actual actions can not be prescribed ahead of time because of the huge combinatorial complexity caused by different industry actors, and the consequent inability to predict the actual system state for which actions would be required [1]. This idea is not radical. However, it is essential for successful and systematic implementation and enforcement of the recently approved mandatory ERO standards.

Finally, we suggest that near-real time quantifiable actions can only be supported by novel numerical tools. In particular, instead of largely monitoring and analyzing for possible problems, numerical tools are also needed for enabling decision making according to the quantifiable performance criteria. Current operating practices are a mix of analysis tools and human decision making. The main body of this paper is devoted to illustrating today's practices and the missing numerical tools. This is illustrated using an NPCC equivalent system model. While the model used in this paper largely resembles power generation, demand and transmission patterns of the actual NPCC system, it is used here for illustrative purposes only.[1] Similar analysis can be carried out for any other regional systems.

A. Paper outline

In Section II we state and analyze the problem of reliable operations of the equivalent NPCC system assuming its current hierarchical system organization. The operating (short-term) reliability is the problem of serving system load in an uninterrupted way during any single- or double-contingency. [2] Posing this problem requires a mathematical model of the physical system and the performance metrics for measuring how well the customers are served. While many papers have been written on this general subject, very few papers explicitly concern the choice of performance metrics [2], [3]. There are even fewer references concerning the tradeoffs between the robustness (reliability) of the system during unplanned events and its optimal economic performance (efficiency) during normal conditions [4], [5]. It is well-known that robustness and efficiency are generally exclusive of each other. Given that large contingencies are relatively rare events, it is generally inefficient to maintain large stand-by reserves just in case these occur. One possible way to overcome this problem is to monitor systems in almost near-real time and adjust decisions accordingly [6]. How fast decisions must be made depends on the nature of the problem caused by the contingency of interest. Most contingencies lead to a gradual worsening of system conditions and would be possible to manage while adjusting each 10 minutes or so.

The basic objective of this paper is to demonstrate potential benefits of on-line monitoring and scheduling. To do this, we first briefly summarize the mathematical model of the physical system, and review both reliability performance metrics and efficiency criteria used by the industry. Given that there is very little data illustrating the interdependence between these performance metrics, we proceed to study them by means of simulations.

In Section V we carry out contingency analysis using the equivalent model of the NPCC system in order to study robustness of this system with respect to equipment outages. A typical approach to contingency screening is simulated, and the list of critical contingencies is found. In the same section some conventional numerical tools for contingency screening are discussed. Their use is illustrated on the same system. Today's approach is inherently preventive and does not rely on scheduling other resources once a contingency occurs. Examples and counterexamples to the current industry practices are presented concerning results based on such approach.

In Section VI a qualitatively different approach to contingency monitoring and management is introduced. As system conditions change, AC OPF software is used to detect critical contingencies while allowing for corrective actions to be taken. All single and double branch and generation outages are simulated in order to identify truly critical contingencies for which there is no combination of corrective actions which would make the system feasible. The key question for the non-feasible contingencies concerns the critical physical limits which need to be relaxed in order to make these critical contingencies feasible.

In Section VII we consider a candidate economic transfer which has been known to contribute significantly to providing the least cost generation to the NPCC system as a whole. One such case is transferring hydro power from Niagara and delivering it to New York City area. At present not all of available hydro power is delivered because of so-called Central-West real power transfer limit. Two experiments are carried out. First, a P-V curve is computed to determine the limit to this transfer beyond which it would not be possible to obtain a power flow solution. Next, a qualitatively different question is asked concerning the limits to the same

[1] The model used is an equivalenced representation of a very large physical system and it only allows certain level of representation and related conclusions.

[2] An analogous formulation could be posed for any other control area or region. NPCC is used here for illustrative purposes only.

transfer while adjusting other available resources so that this transfer is maximized. The results are compared and discussed.

Finally, in Section VIII, the results obtained while attempting an economic transfer independently from reliability considerations are combined with the results obtained when attempting the most reliable operations, independently from economic considerations. In the real-world operations engineers routinely cut the economic transfers back to ensure that the system is reliable during any single contingency. The results reveal the truly multi-dimensional features of a complex network system. These reasons point out that none of the critical contingencies can be made feasible by reducing the economic transfer of interest. Moreover, the economic transfer is not affected by the contingencies themselves. The two are by and large independent in this case.

In the closing Section IX we point out the need for novel numerical methods capable of delineating boundaries between economic transfer and reliability-related limits. Based on the analysis in this paper, we conclude that carefully designed numerical tools must be used to do this. Moreover, the numerical tools are key to deciding which are the most critical limits as conditions change, and how to manage them in a robust way. More generally, it is concluded that without pro-active reliance on systematic adjustments of available resources as the system conditions change it is no longer possible to ensure that the mandatory reliability standards are enforceable in on-line system operations. Currently utilized numerical tools and operating practices are both prone to leading to wrong conclusions and are overly conservative. Because of this, it becomes essential to develop and implement novel robust software for monitoring and dispatch in order to make the most out of available resources.

II. Electric Power System Architecture: A Complex Interplay of Physical, Regulatory and Data Management Processes

The electric power industry has been at a crossroads for quite some time. It has been undergoing a transformation from a largely static industry with well-defined rules and regulations for providing electricity services, to an industry with many dynamics driven by organizational and technological changes. This process requires careful re-thinking of opportunities and challenges offered by such changes. Given the complexity of the system, the opportunities and challenges are not straightforward to identify and manage.

In this paper we are particularly concerned with the interdependence between the physical system performance, reliability metrics established by the regulators, and the monitoring and control infrastructure (SCADA) required to implement/enforce these metrics.[3] In what follows we will show that if this interdependence is not taken into consideration, there will be large inconsistencies between the physical performance of the system, and the regulatory rules in place. Or said differently, it will take a systematic allignement of all three layers in the future electric power systems for the performance metrics to be implementable. We start by defining the basic physical model of the electric power grid.

A. Physical Characterization of an Electric Power System

A typical electric power system is characterized by defining: [4]

- capacity and rate of response for power plants;
- Loads;
- transmission lines and their thermal limits;
- switching equipment, such as controllable capacitor shunts and phase-angle regulators;
- power-electronic switching devices, such as DC lines and FACTS; and
- network connections of these individual hardware.

More specifically, the characterization of individual components and the network constraints, respectively, is as follows:

- The constituent relations of all of its components, such as:

  a) Each generator i is characterized as a component whose real power output can be set at any value P_{Gi} within the physical capacity of the generator, namely the minimal power allowed to generate $P_{Gi}^{\min}$ and the maximum power able to produce $P_{Gi}^{\max}$, for all generators i. Also, each generator can maintain voltage (magnitude) at its terminals V_{Gi} constant as long as there is enough reactive power generation within the minimal limit Q_{Gi} and $Q_{Gi}^{\max}$. These constraints are expressed as

$$P_{Gi}^{\min} \leq P_{Gi} \leq P_{Gi}^{\max} \quad (1)$$

$$Q_{Gi}^{\min} \leq Q_{Gi} \leq Q_{Gi}^{\max} \quad (2)$$

  When the reactive power generation limits are reached, voltage at the terminals of a generator V_{Gi} is no longer maintained constant, and, under such conditions must be maintained within the limits to protect the generator from being damaged, namely,

$$V_{Gi}^{\min} \leq V_{Gi} \leq V_{Gi}^{\max} \quad (3)$$

[3] In this paper we use the term SCADA to mean monitoring and control system, of a general structure, not just the structure currently in place.

[4] The transient response is not considered in this paper, therefore no dynamic equations defining this. The assumption is that the transitions from one to the next state are stable. For more detailed model see [7].

If these limits are violated the under-and/or over-voltage protection of power plants will disconnect the power plant from the rest of the system for safety.

b) Each load j is characterized as a sink of constant real and reactive power P_{Lj} and Q_{Lj}, respectively. The voltage magnitude at the bus where the load is connected V_{Lj} is allowed to vary within the pre-specified minimal and maximum limits $V_{Lj}^{\min}$ and $V_{Lj}^{\max}$, respectively, namely [5]

$$V_{Lj}^{\min} \leq V_{Lj} \leq V_{Lj}^{\max} \tag{4}$$

.

c) Each transmission line connected between buses i and j is characterized by its lumped parameters, resistance R_{ij}, reactance X_{ij} and shunt capacitance B_{ij}, and also by its thermal limit $F_{ij}^{\max}$ [6]

$$F_{ij}^{\min} \leq F_{ij} \leq F_{ij}^{\max} \tag{5}$$

Depending on the time over which the line constraint would be active, the line flow limit can be lower or higher. For purposes of discussion in this paper, it is important to differentiate this limit, which is defined by the properties of the line, from the line flow transfer limits introduced for purposes of avoiding system problems.

d) Each controllable shunt capacitor is characterized by its electrical parameters and the control rules. For purposes of this paper it is important to observe that the shunt capacitor has control limits

$$C_i^{\min} \leq C_i \leq C_i^{\max} \tag{6}$$

e) Each controllable transformer is characterized by its electrical variables and the control rules. Similarly, each transformer has limits to its controllable range of inductance

$$L_{ij}^{\min} \leq L_{ij} \leq L_{ij}^{\max} \tag{7}$$

- Network power flow constraints at all nodes, stating that real power injected into any bus i must equal real power flowing away from the bus into the network.

$$P_i = P_{Gi} - P_{Li} = \Sigma_j \in C_i F_{ij} \tag{8}$$

Similarly, the reactive power balance at each bus must be met.

$$Q_i = Q_{Gi} - Q_{Li} = \Sigma_j \in C_i Q_{ij} \tag{9}$$

In the next Section II we review performance objectives for today's hierarchically organized industry whose reliability performance metrics were defined and recently approved by the ERO.

III. Performance Objectives of Operating the Physical System

The above model of the electric power system is only one component of the entire electric power system architecture. There are at least two critical components: the regulatory organizational layer and the information SCADA layer. These layers have evolved over time, and were not simultaneously designed. Utilities attempt to implement regulatory requirements set by their States. These procedures are followed with an eye on minimizing costs. However, making the most out of the available resources despite difficult to predict demand variations and unplanned equipment failures is a serious challenge. For detailed description of the inter-dependence between these three layers, see [1].

In the past, the physical portion of the electric power system has been horizontally structured into control areas (utilities). A typical region in the United States interconnection comprises several control areas, often under the jurisdiction of different States. Using NPCC system as an example, the performance of the electric power system in this region is governed by two countries and several States. Within the U.S. portion of the NPCC system, several utilities are regulated by one State (in NY), while in the other parts of NPCC system (NE) individual utilities are regulated by the separate State regulators. Shown in Figure 1 is the one-line diagram of the equivalent NPCC system described in [8]. The buses in the reduced model are individually selected to provide a good representation of the Northeastern US bulk electric power system, particularly in New York and to a lesser extent in New England, while limiting the size of the model to 40 buses or less. Correspondingly, New York is represented by 19 buses, New England is represented by 8 buses, Ontario is represented by 5 buses, Pennsylvania - New Jersey - Maryland (PJM) is represented by 2 buses, and Quebec and the Maritimes Region are each represented by a single bus radially connected to New York and New England, respectively. Thus, the reduced electrical model has a total of 36 buses. Within New York control area there are 11 transmission providers responsible for serving their customers.

A. Performance Metrics for Reliable Service

In order to ensure reliable service at reasonable cost under the increasingly complex use of the grid, the key

[5] To start, these limits are specified strictly for purposes of ensuring that the customers power quality specifications are met. Depending on the type of load and the degree of aggregation, more complicated load characterization can be used, such as voltage and frequency dependent real and reactive power consumption of the load. Also, an important open question concerns representation of load participating in demand-side management.

[6] The power flow is limited in both directions. The F_{ij}^{min} defines the thermal limit in the opposite direction. Most frequently, the two thermal limits are the same in magnitude. We differentiate the notation in preparation for introducing the system-related limits, which are generally not the same in magnitude for a given line.

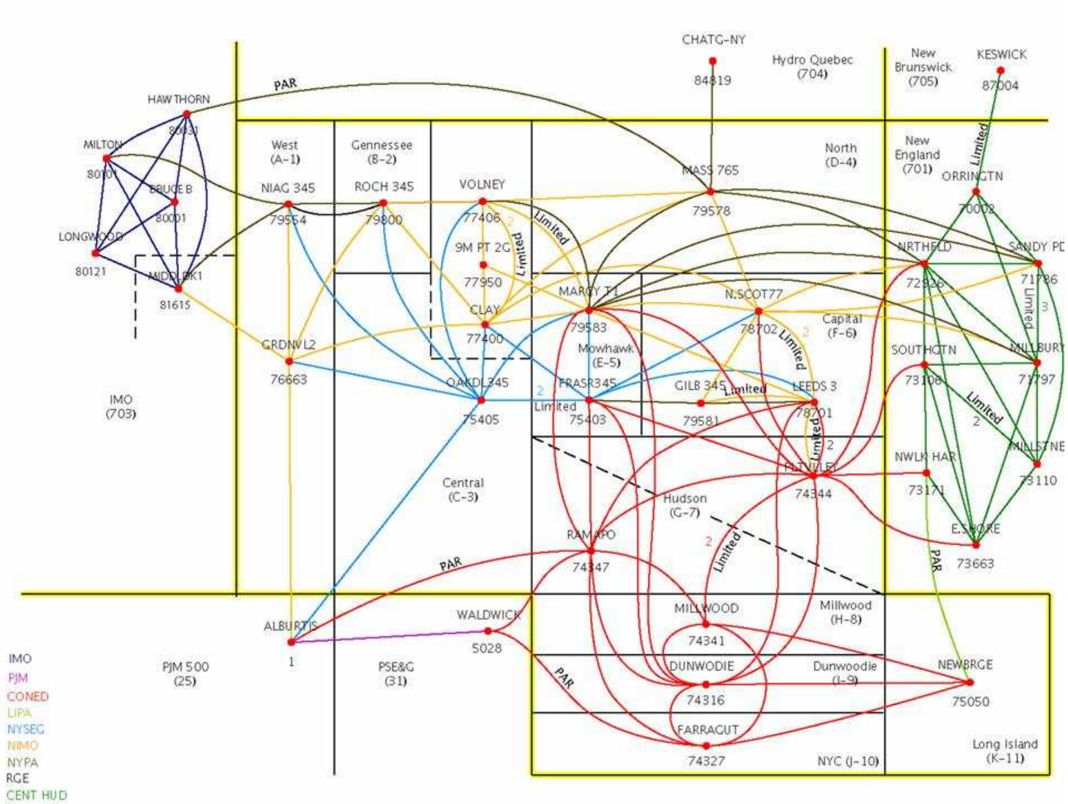

Fig. 1. One-line diagram of the equivalenced 36-bus model. Note that: “PAR” indicates that the corresponding line contains a phase angle regulator; “Limited” indicates that the corresponding line has a power flow limit; “(2)” and “(3)” indicate that the corresponding line is a double and triple line, respectively; and the line color indicates line ownership as listed in the color key.

to bulk power systems reliability in the future, as in the past, is a) sound planning and operating criteria; b) transmission transfer capabilities and limits based on those criteria; and c) effective methods and procedures for monitoring, assessing, and implementing compliance with the criteria.

An important observation for purposes of this paper is that there are currently no directly quantifiable metrics relating the reliability requirements set by the regulators, to the industry standards supporting the $(N-1)$ reliability standard. For quite some time major utilities have relied on their SCADA systems to monitor system equipment status and to schedule available resources at the least O&M generation cost without causing any technical operating problems. The reliability standards set by the State regulators were implemented in control centers using SCADA systems and by utilizing computer algorithms known as unit commitment, security-constrained economic dispatch, and the like [9].

On-line scheduling of real power generation is mainly done at the transmission level, given that there are no small distributed generators (DGs) connected to distribution systems. Although the majority of small-scale disruptions in electricity service take place due to equipment failures in the distribution portion of the system, there is very little, close to none, near real-time monitoring of equipment status or automation to respond to such equipment failures. There are major efforts under way toward improving this situation, particularly by developing the distribution management systems.

Implied in current industry rules and regulations is the requirement that all the equality and inequality constraints (1)–(9) above must be simultaneously met in order for the network protection not to disconnect pieces of equipment whose inequality constraints are violated, and for the network as a whole to balance. This must hold for any network topology in order for protection not to activate. Current industry practice is to ensure that this is met, i.e. that there exists a feasible steady state network solution even when any single (or double) equipment gets disconnected from the power network. Moreover, the NERC reliability standard requires that actions be taken so that within 30 minutes the system is brought back to normal, even without the equipment which has failed.

IV. Current approach to ensuring short-term system reliability

It is fairly straightforward to observe that there are potentially many combinations of power injections that meet the reliability constraints for a given power network, such as the NPCC equivalent system. Typically, the larger network, the higher the number of such combinations is.

Current approach to meeting reliability is based on what amounts to a preventive approach to managing the worst case scenarios. During normal operations, when there are no equipment failures, resources are scheduled so that there is sufficient reserve to manage the worst case equipment failures in case these occur, without affecting customers for at least 30 minutes. It is further implied that actions would be taken to bring the system back to normal (meaning that all physical constraints are met even without the failed equipment). This means that sufficient resources should be available to manage the first equipment failure without resorting to any rescheduling of the resources during the first 30 minutes (preventive); in addition, it is required to have enough resources to reschedule these so that any single contingency does not violate reliability constraints for 30 minutes after the remaining resources have been adjusted (corrective after 30 minutes).

A. *Setting Transfer Limits for Short-Term Reliability*

In addition to observing power flow limits (5) so that the transmission equipment does not get overheated and damaged, it is necessary to ensure that the reliability constraints (1)-(9) are met even during the most critical equipment failures, according to the $(N-1)$ or $(N-2)$ reliability standard specifications. Since the current operating practice is preventive, with the objective of ensuring that there is enough generation and transmission reserve to serve the customers even during the most critical single equipment failures without adjusting any other resources, this practice requires imposing tighter constraints on power flows so that enough transmission and generation reserve margin is available in case a contingency occurs.

Extensive off-line simulations are carried out annually when planning new equipment, and at the operations planning stage, when scheduling routine equipment maintenance, in order to assist with these preventive decisions. Most of the simulations used are analysis-oriented. No systematic optimization of resources is done at the planning and/or operations planning stages. Instead, for the forecast demand, the worst case contingency scenarios are identified and power flow studies are carried out to analyze if these scenarios would be reliable. If not, instead of optimizing all the resources, only selected resources are assumed to participate in re-scheduling. In order to ensure that the worst case scenarios are feasible the power flow transfers are limited at some key transmission paths. This means that for some of the transmission lines the thermal limits (5) must be reduced further to

$$F_{ij}^{\min,rel} \leq F_{ij} \leq F_{ij}^{\max,rel} \qquad (10)$$

for a subset of transmission lines which are identified to be critical for system-wide reliability. Similarly, procedures are put in place to limit the load voltages to

$$V_{Lj}^{min,rel} \leq V_{Lj} \leq V_{Lj}^{max,rel} \qquad (11)$$

for a subset of loads which are considered to be critical for ensuring reliable services.

The modified limits (10) and (11) are then observed when the real power generation is dispatched during operations. In what follows we examine the numerical tools currently used for determining the reliability limits.

B. *Defining the Worst Case Scenario for a Given System*

To start, defining the worst case scenario for a large power grid is a very combinatorial problem. One would need to simulate all combinations of contingencies for low, nominal, and peak loading conditions and analyze each of these scenarios to determine if the reliability limits (1)–(9) are met. Since the system planners and operators prefer to understand their system response to the $(N-2)$ contingencies, this leads to a practically unmanageable number of power flow simulations of all double contingencies. To make matters worse, simulating the most critical conditions often leads to non-convergent numerical outcomes.

Because of the overwhelming computational complexities, approximate screening procedures are carried out to assess the number of critical failures. One of the routinely used methods is to test if the linearized real power flow (8) can be solved subject to the reliability constraints on real power line flows (10). The implied assumption is that the reactive power/voltage reliability problems would be accounted for while reducing the thermal limits of transmission lines (5) to the reliability-related real power line flow limits (10).

This brings us to methods for determining real power line flow limits (10) which are supposed to account for the reactive power/voltage reliability problems i.e. violations of reactive power balance equations (9) and/or reactive power generation limits (2) and/or voltage limits (3)–(4). Current practices have been a combination of historic procedures specific to each system and/or use of some variation of a $(P-V)$ curve approach to defining the transfer limit of a transmission line, or sets of lines (corridors, interfaces, flow gates). The $(P-V)$ curve-based methods basically amount to increasing demand at the receiving end of the power system until the AC power flow begins to experience convergence problems. A curve is plotted with the power transfer on the x-axis and the receiving-end voltage on the y-axis. The real power is either increased at specific generators which are designated to reschedule to support the power transfer of interest, or, it is otherwise, compensated from the slack bus by default.[7] Real power transfer reliability limit (10) is usually set to be slightly below the critical point at which the AC power flow fails to converge, typically 5% less than the limiting transfer.

We point out that this practice may fail to identify the most critical contingencies all together, for at least two major reasons. First, some of the major reactive power/voltage problem-related contingencies may be simply missed through this approximate two-step approach. Second, the problem is so combinatorial that it is impossible for any practical purposes to predict what the worst case scenario actually is. The $(P - V)$ curve studies assume everything else fixed, and only vary real power loading. Depending on how the other resources are scheduled, the transfer limit can vary significantly. We illustrate this in the numerical simulations part of the paper for the NPCC system.

C. *The Critical Role of On-Line Scheduling in Ensuring the Short-Term Reliability*

The electric power systems of today are fairly robust with respect to losing synchronism and/or uncontrollable fast voltage collapse; out of many equipment failures, there are not that many leading to dynamic problems right away. A more common scenario is the one of a gradual degradation of voltages and flows away from their steady state limits. During the August 2003 blackout it took a sequence of several large equipment failures over couple of hours to arrive at the conditions of fast instabilities.

This observation raises questions concerning the potential of routine on-line adjustments of all available resources during both normal and abnormal conditions. In this paper we take a closer look at the dependency of reliable service on systematic scheduling of available resources. The objective is to illustrate the observation that how reliable the system is in the actual operations is extremely dependent on the on-line actions. This is mainly because of the combinatorial complexity which has become impossible to plan in a preventive manner.

In what follows, we present for the NPCC equivalent system the results of a full-blown contingency screening, and analyze the implications on the accuracy of the short-term reliability assessment. We then illustrate potential of using on-line robust re-scheduling of resources for enhancing system reliability.

V. CONTINGENCY ANALYSIS OF THE NPCC EQUIVALENT SYSTEM

The power flow solution for the NPCC system described in [8] is used as the starting point around which short-term reliability studies are carried out. This solution has short-term reliability in the sense that it satisfies all equality and inequality constraints (1)–(9) when the load demand pattern is as given (normal), and all equipment components are functional. Therefore, there is no need to modify the line flow limits (5) for purposes of ensuring that the network as a whole is reliable for the given supply/demand pattern. It can be seen in the NPCC system data provided in [8] that out of 117 lines in the NPCC equivalent system, 17 lines are given thermal limits (5028-74347, 7002-87004, 71786-71797 (both),73106-73110,74316-75050,74316-74327,74341-74344,74344-78701,75403-75405, 75403-79581,77400-77406,77406-79583,78701-78702,78701-79581 and 79584-79800). [8] However, in order to ensure that the system would meet the $(N-1)$ and $(N-2)$ reliability criteria, it is necessary to assess the system response to taking out equipment of interest and determining the most critical failures.

A. *Dependence of Critical Contingencies on the Numerical Tools Used*

In what follows we first describe the results obtainable using current numerical tools for contingency screening. Typically, two methods are needed: First, to determine the largest real power transfer of interest during normal conditions, and second, a screening method for detecting contingencies which, if they were to happen, would violate this maximum power transfer of interest. These contingencies are designated ”critical” and the transfer is then reduced in order to not violate this limit under any of these contingencies.

B. *Determining the Allowable Real Power Transfer Limit*

As an illustration of current operating practices, consider the NPCC system. It is economically attractive to transfer as much as possible real power generated in the Northwestern part of NY to the NY City large load center. This power is hydro-generated and its O&M cost is much lower than the cost of nearby power plants. In order to determine how much can be transferred

[7] It is important to recall that slack bus is simply a mathematical artifact and that running the power flow for determining the voltage limit below which the power flow solution can not be found is a grossly distorted representation of how is the power increase induced in the actual operations.

[8] Only thermal limits on actual, non-equivalenced lines are observed.For a full-blown system each line has a thermal limit specification.

without violating reliability limits, a typical procedure is to run off-line a sequence of full-blown AC power flows by 1) increasing generation at the sending point, 2) increasing the load at the receiving end, and 3) enforcing the real and reactive power limits at the slack bus. For determining the power transfer limit (Central-West) this experiment would mean 1) increasing generation at Niag 345 (bus # 79584); 2) increasing load at Farragut (bus # 74327; and 3) enforcing the real and reactive power generation limits at the slack 9M PT 2G (bus # 77950), see Figure 1. Increasing generation into the sending bus incrementally and simultaneously increasing the load by the same amount at the receiving bus results in the largest power transfer possible during normal operations with all equipment functional of about 6050 MW. It is important to observe that at the point when no feasible solution can be found, Jacobian is not singular, but the real and reactive power balance equations (8) and (9) cannot be met.

This transfer is obtained by running a standard AC power flow. The power injection limit computed by this procedure determines the net power (sent and delivered) via transmission lines connected to the sending bus Niag 345 and to the receiving bus Farragut. In the actual implementation this limit could be implemented by defining flow limits on one or more lines comprising the cut-set between the sending and the receiving nodes.

A closer look into the results of this power flow show that the real power limits at the slack bus are exceeded. This is an artifact of a typical power flow formulation, since the power out of slack bus needed to maintain the voltage magnitude and phase angle unchanged is a by-product of the basic power flow calculation. If care is not taken to re-iterate the power flow until the slack bus generation is within the limits, this result could be highly misleading, and overly optimistic since there would not be enough power at the slack bus to implement the power flow solution computed.

To obtain more realistic results one could designate a slack bus further away from the area where the transfer is increased. By choosing slack bus at Alburtis (bus # 1) and repeating a sequence of AC power flow simulations one obtains the same maximum power transfer (since the power flow does not check the slack bus generation limits).

Based on this analysis, we observe that the maximum real power transfer using conventional power flow studies, although dependent on the choice of a slack bus, is often not detected while running typical power flow programs which do not observe generation limits of the slack bus. Generally, the further away the slack bus from the power transfer studied, the higher power transfer is possible.

The power flow result is hard to implement because in the actual operations there is no slack bus. In practice the slack bus is chosen far away from the study system. Also, when studying transfers, slack bus is normally used to balance the incremental losses caused by this transfer. For example, if the slack bus limits are violated, some other generators must be turned on to bring the power generated at the slack bus back to within the slack bus. Some commercial power flows have the capability to model such distributed slack bus, and some others do not. [9]

C. Accounting for the voltage limits at the receiving side of the power transfer

Another generic complication with reliance on power flow studies for determining the maximum power transfer comes from the inability to enforce voltage limitations explicitly. Power flow computations often result in the P-V curves whose extreme power corresponds to the receiving end voltage outside of acceptable limits. This raises the question about the rationale for defining voltage limits at the high voltage levels. It is, therefore, not clear if the computed real power transfer could be implemented. This complication is not easily solvable in today's industry practice for several reasons. The acceptable voltage at the EHV level should reflect the specifications given by the end users, but the models typically employed at the (I)SO centers are aggregate models of many customers at the lower voltage levels. The system model becomes unacceptably complex with attempts to represent all voltage levels in great detail. If it were not for this complexity, the acceptable voltage at the receiving end should be the higher of the two voltages (one determined in a bottom-up way by aggregating many lower level load specifications, and the second the voltage obtained when the power flow fails to converge). It is relatively straightforward to create an example of a maximum power transfer obtained using power flow analysis which is not within the pre-specified voltage limits. This issue leaves some confusion regarding the determining criteria for voltage limit specifications.

D. Screening for Critical Contingencies

A typical approach is to screen all single and/or double contingencies for their impact on the power transfer limits. In other words, a contingency will be flagged "critical" if a power flow for the topology when the contingency is simulated either does not converge and/or it results in power flows which exceed the real power line flow limits determined above. If this occurs, a system operator decides by how much to further reduce the power flows during normal conditions so that if any critical contingency occurs, the voltage-related line flow limits are not exceeded. This ultimately determines how the

[9] The comments in this paragraph provided by Dr. Xiaochuan Luo.

resources are dispatched during normal conditions. At present this adjustment is not optimized. It is generally a combination of off-line studies and operator's knowledge of location at which power flow injections may most effectively ensure that the flows stay within the feasible limits.

Since determining the voltage-related power flow limits requires extensive computations, a typical approach is that the maximum power transfer is determined at the planning or, at best, at the operations planning stage. The curve is not routinely re-computed in operations.

On the other hand, a distribution factors-based screening for critical contingencies is done as the loading conditions change and economic dispatch is performed. Real power economic dispatch is generally suboptimal in order to keep the real power flows during normal conditions at levels so that if any critical contingency occurs these are not exceeded. This is an indirect way of taking into consideration the AC power flow limitations while dispatching real power. This practice started in early 1990s and is a fairly standard procedure in many control centers.

1) Critical line and generator contingencies found: For purposes of bench marking, a nonlinear power flow was run for all single generation and branch outages, without resorting to the distribution factor-based contingency screening. Disconnecting transmission lines 70002-87004, 70002-71786 and 84819-79578 resulted in nonconvergent power flow solutions. However, out of these three contingencies only line outage 70002 -71786 had a problem meeting real and reactive power balance constraints. The other two contingencies had singular Jacobian.

Similarly, the generators at buses 71797, 70002, 74347, 73110, 76663, 75050, 71786,84004, 80101 and 79584 were found to result in a non-convergent power flow. These contingencies lead to violations of real and reactive power balance equations at some buses in the system.[10]

VI. A New AC OPF-Based Assessment of Non-Feasible Single and Double Contingencies

We have simulated all contingencies using next a nonlinear AC OPF program [10] to detect contingencies which do not result in a steady-state solution within the short-term reliability limits. Only outage of line connecting nodes #77406 (Volney) and #77950 (9M PT 2G) was found to be not feasible. As expected, a combination of simultaneous failure of this line with the failure of any other line failure in the system also fails to result in a new reliable steady-state. In addition to these non-feasible double contingencies, there are several combinations of two simultaneous line failures which fail to result in a reliable steady-state solution. These lines are two lines between: 1) 5028–74347 and 1–5028; 2)74316-74327 and 5028-74327; 3) 73171-73663 and 73106-73171; 4) 74327-74341 and 74316-74341; 5) 77400-77406 and 77400-77406; 6) 79578-79583 and 77400-77406; and 7) 79578-79583 and 77400-77406.

Because of potential failures of these lines, the minimum and/or maximum line flow limits F_{ij}^{min} and F_{ij}^{max} of some transmission lines, respectively, would have to be reduced to some $F_{ij}^{min,rel}$ and $F_{ij}^{max,rel}$, respectively, in order to ensure that the system is reliable even when these components are not connected to the grid. This is what current preventive approach to short-term reliability requires. The flow limits do not have necessarily to be reduced on the lines whose failures cause non-existence of a steady-state solution. There is at present no systematic way of computing the major contributors to the non-existence of a steady state solution. Instead, since it is known that the change propagates locally within an electric power system, it is reasonable to conjecture that the failed line connecting nodes m and n would create major changes in power flows in the transmission lines directly connected to the sending and the receiving ends of the failed line. Therefore, lines for which no steady state solution exists during their failures and the neighboring lines are candidate interfaces for reducing line flows for reliability reasons.

We have also simulated all single generator outages for the NPCC equivalent system. Using an AC OPF it was found that total of ten (10) single generator outages would not have a feasible steady-state solution following their failure. These are generators located at buses 71786, 70002, 74327,1, 71797, 73171, 75050, 76663, 80101 and 87004. Very few cases of double generator failures were found to be infeasible, if the failures of the individual generators were feasible.

While computationally involved, the above analysis determines accurately the non-linear AC power flow response of the system to all single and double contingencies, and, therefore, potential problems.

A. Dependence of Critical Contingency Screening on the Numerical Tools Used

A comparison of the list of critical contingencies obtained by using (a) AC power flow, (b) approximate DF-based real power flow estimates, and (c) AC OPF shows that these lists are not identical. An additional analysis is required to explain these differences.

Here we just discuss differences concerning critical line outages. A close look at the one-line diagram of the NPCC system reveals that buses 87004 and 84819 become disconnected from the rest of the system when

[10] The simulations using power flow are done by Dr. Jovan Ilić.

lines 7002-87004 and/or 84819-79578 are out of operations. A power flow program must have an additional test concerning line outages which result in disconnected graphs. A power flow program used here does not have such test, and, leads to a conclusion that the Jacobian of the original system becomes singular, and, could therefore not use a Newton Raphson power flow algorithm to solve the power flow equations when the lines leading to a disconnected graph are disconnected. This observation eliminates the two out of three critical line outages found by running power flows.[11]

On the other hand, the critical line outage 77406-77950 found by running an AC OPF tool was not found when running the power flow analysis. A closer look into this case reveals that this occurred because the power flow program used did not have an automatic check of real and reactive power generation limits at the slack bus. This led to an overly optimistic estimate that this line contingency was not critical.

The results obtainable using the DF-based analysis are completely unrelated to the ones obtained using nonlinear analysis (power flow) or nonlinear scheduling (OPF) numerical tool, and are not discussed in this paper.

Similar analysis can be done to explain differences among generator outages.

These comparisons are used to indicate often hidden dependence of resulting contingency screening on the numerical tools used. Therefore, one must proceed very carefully with conclusions about the actual feasibility problems on a real-world system and possible ways to manage them. Today's numerical tools available to the system operators rarely automate additional considerations, such as the ones illustrated here.

B. Mapping Non-Feasible Contingencies to Modified Real Power Transfer Limits

The next step of reducing the power flow limits at the most effective lines and by the right amount in order to avoid steady-state stability problems caused by the contingencies identified using the above analysis, is complex and non-unique.

As reviewed above, most of the operators use distribution factors for screening out the most critical contingencies. The distribution factor matrix is obtained by linearizing the real power flow equations (8) around normal operating conditions, to compute phase angles of all voltages in terms of network reactances and the change of real power injection changes at the buses affected by the contingencies. Under the assumption

[11]Some commercial power flows can solve multiple island power flows by dynamically assigning a slack bus to each island. Some others, will not let the user solve the power flow if multiple islands exist before the user deletes the other islands. These clarification is provided by dr. Xiaochuan Luo.

Index	Bus #	Index	Bus #	Index	Bus #
1	1	2	5028	3	70002
4	71786	5	71797	6	72926
7	73106	8	73110	9	73171
10	73663	11	74316	12	74327
13	74341	14	74344	15	74347
16	75050	17	75403	18	75405
19	76663	20	77400	21	77406
22	77950	23	78701	24	78702
25	79578	26	79581	27	79583
28	79584	29	79800	30	80001
31	80031	32	80101	33	80121
34	81615	35	84819	36	87004

TABLE I

TRANSLATION TABLE BETWEEN BUS NUMBERS AND INDEXES USED FOR GRAPHICS.

that voltage does not affect real power-phase angle solution significantly and assuming resistive losses are negligible the DF matrix relating changes in injections caused by the simulated outage, and changes in line flows throughout the entire network have a simple linear relation:

$$\Delta \underline{F} = [DF]\Delta \underline{P} \tag{12}$$

where DF is the distribution factor matrix relating line power flow changes to the line power flow injections caused by the equipment failure of interest.

It should be clear from the assumptions made in deriving (12) that problems underlying the critical line contingency 77406-77950 could have not been detected using this approximate formulae. More generally, DF-based contingency screening misses all problems related to any limits other than thermal line limits. Therefore, a qualitatively different numerical method would be needed for overcoming these problems inherent in today's DF-based contingency screening software.

VII. NUMERICAL TOOLS FOR MAXIMIZING ECONOMIC TRANSFERS

While utilities always have reliable service as the first criteria, it has become increasingly important to optimize utilization of available resources at the same time. In order to illustrate the critical role of using the right numerical tools when attempting to make the most out of the available system, we consider the problem of maximizing the bilateral transfer from Niag 345 (bus 79584) to Farragut (bus 74327).

Two numerical tools are utilized here for assessing the maximum possible transfer.

The first is an experiment introduced above in context of feasible transfers, based on increasing real power generation injected into 74584 and increasing simultaneously the real power load at 74327. A power flow was run to assess the feasibility of incremental transfers around the nominal conditions. Such an experiment has resulted in feasible real power injection of 6050MW, or roughly 1300MW above starting conditions. Because of large reactive power compensation at bus 74327, voltage at this bus remained near constant until the highest transfer limit was reached. Jacobian did not become singular, but power flow balance equations were not possible to meet. This behavior is not likely to be seen when using a detailed system model, instead of the equivalenced one. The reactive power compensation at bus 74327 is much smaller than what its aggregate representation is in the equivalenced model that accounts for the support of all other buses which are eliminated.

A. A New AC OPF Based Transfer Maximization

The second experiment was based on an AC OPF numerical tool which allowed for real power and voltage to adjust at other buses as the bilateral transaction transfer was optimized.

To start, effects of optimizing total system loss through voltage dispatch, and the resulting feasible transfer to load at bus 74327 are analyzed for several choices of slack bus. If all real power generators are fixed, that is if there is no slack bus, it is possible to transfer additional 200 MW beyond the starting loading. For slack buses at 79584 (sender), 74327 (receiver),77950 (9M PT 2G), 71786 (Sandy Pond) and 1 (Alburtis), respectively, all maximum feasible transfer are around 300 MW without voltage dispatch. These transfers change significantly when optimizing voltage dispatch, and result in maximum feasible transfers of around 1500MW for all slack buses, except for the slack at the receiver which results in the maximum 1900 MW feasible transfer. Shown in Figure VII-A is the optimal voltage dispatch and its comparison with the starting voltage profile with bus 1 (Alburtis) as the chosen slack bus. It can be seen from this figure that the differences between the starting voltages and the optimized ones are significant.

Next,the effects of optimizing only real power dispatch in support of the same bilateral economic transfer from 79584 to 74327 are analyzed. Shown in Figures **??** and VII-A are the optimum real power generation and the differences between the optimized and starting generation, respectively. This dispatch results in an additional 2780 MW beyond the starting transfer.

Finally, a combined effect of optimizing both real power generation and voltage dispatch in support of the same economic transfer is analyzed. Shown in Figures VII-A, VII-A and VII-A, respectively are the optimum voltage dispatch, optimum real power dispatch and the difference between the optimum and starting real power dispatch. This combined optimization results in 3040 MW transfer increase above the starting.

Moreover, since the AC OPF numerical tool used for these simulations computes the Lagrangian coefficients with all constraints, it became possible to identify the most relevant constraint. The most significant Lagrangian coefficient was the one associated with the real power thermal limit of the line 74316-74327. A look at the one-line diagram of the NPCC system provides a simple explanation of this result, since this line was directly connected to the bus where the load was increased. It is important to recognize that the conventionally used DF-based analysis of real power transfer limits in this case would not show the same answer because the DF-analysis does not seek scheduling of other available resources. It would, instead, result in a much more conservative bilateral power transfer. Once the cause of the transfer limit was found, we removed the thermal line limit 74326-74327 and the possible incremental transfer

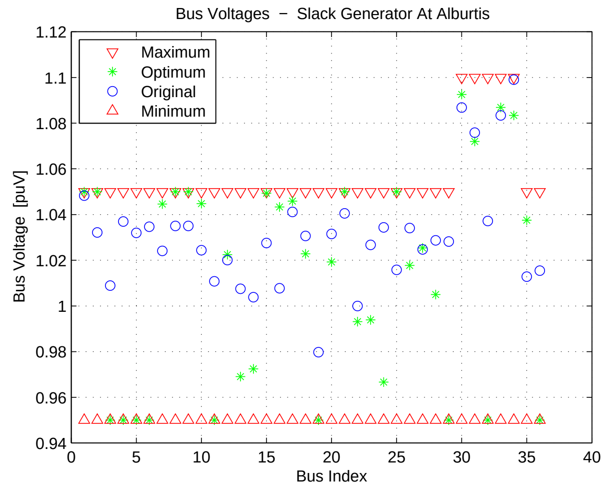

Fig. 2. Optimal voltage dispatch with Alburtis as a slack bus

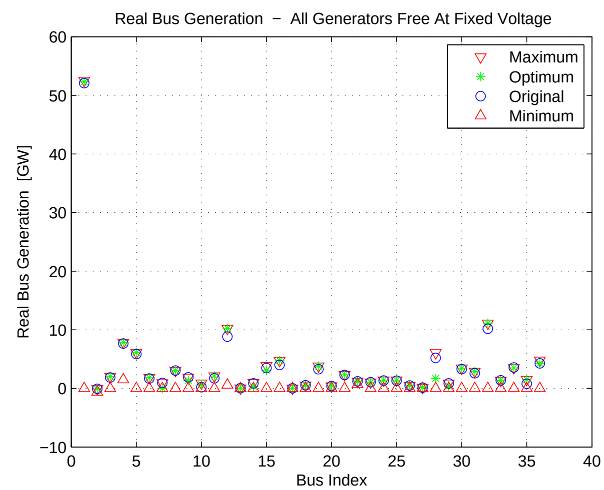

Fig. 3. Optimum power generation schedules without voltage adjustments

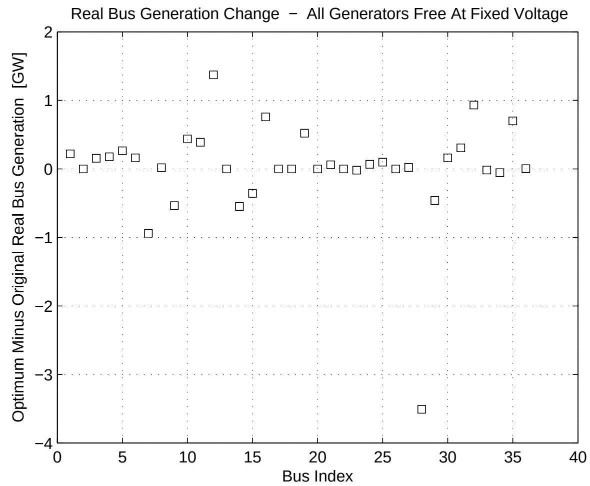

Fig. 4. Difference between the optimim and starting generation schedules without voltage adjustments

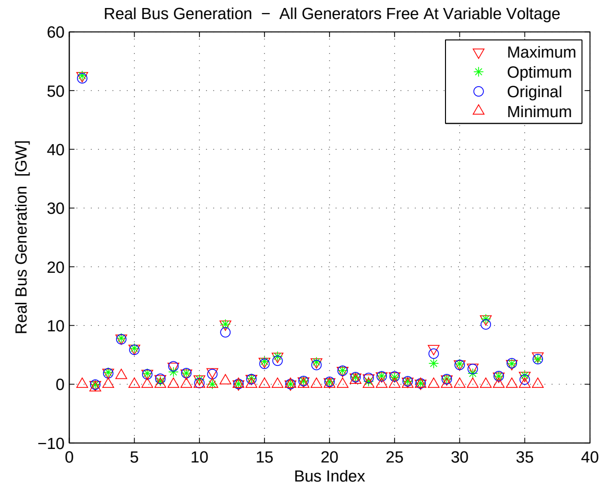

Fig. 6. Optimum real power generation with voltage dispatch

Fig. 5. Optimum bus voltage dispatch

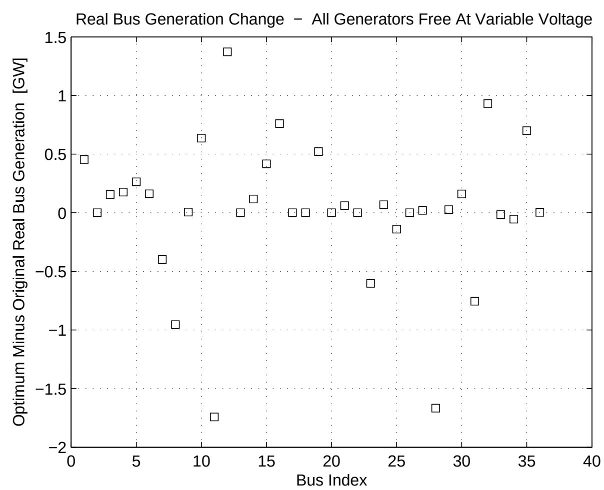

Fig. 7. Optimum real power generation adjustments with voltage dispatch

became about 6000MW.

The above results point into potential for significant improvements when supporting bilateral transfers by adjusting other resources within the system. In this paper only feasibility of such economic transfers is studied. Many questions, in particular the O & M economics of such rescheduling must be studied.

VIII. Relations Between the Critical Contingencies and Maximum Economy Transfers

We finally arrived at the most difficult question concerning the tradeoffs between reliability limits and the economic transfers. In order to assess this interdependence, we have analyzed the critical line outage 77406–77950 and the bilateral transfer between 74584 and 74327. It was found that the line outage critical contingencies are largely unrelated to the economy transfer. Namely, the critical contingency remained critical even at the nominal system transfers, i.e. the economic transfer did not make the scenario any worse. On the other hand, the economic transfer determined during normal conditions was the same even when the critical line contingency was simulated.

These observations should not be surprising for several fundamental reasons. Critical contingencies at nominal power flow levels, prior to attempting additional economic transfers, are generally caused by the limits somewhere else on the system than by those affected by the economic transfer of interest. Additional analysis is, therefore, required prior to automatically reducing the power transfers based on approximate DF-based real power flow line estimates. This multidimensional nature of the complex electric power grid clearly indicates the need for novel numerical methods essential for:

- detecting critical contingencies with and without allowing for other sources to adjust when the contingency happens;
- assessing the major causes of the critical contingencies;
- finding the most effective corrective actions.

Depending on the network topology and the operating conditions, it is, indeed possible for reliability and economic transfers to become very inter-dependent, particularly when all resources are optimized and not only some bilateral transfers [11]. Determining these interdependencies is beyond human operator's ability to carry out and novel numerical tools are essential.

IX. Conclusions

Reliability standards can not be defined without considerations of how enforceable they are in the actual operations. This should be the major issue as the Electricity Reliability Organization (ERO) begins to define its functions. There is a definitive need to relate more closely the multi-dimensional aspects of reliability to the current $(N-1)$ reliability standards, some of which recently became mandatory, and, furthermore, to the operating procedures necessary to meet these standards.

We make a general observation that with today's SCADA and numerical tools in place these reliability metrics are generally not implementable. We make this case by reviewing current operating practices in a typical region, such as the NPCC system. We then propose that SCADA system with more on-line quantifiable decision making would be essential for implementing such reliability metrics.

We suggest that the effectiveness of enforcing reliability standards greatly depends on both operating procedures in place, and the numerical tools used to assess the reliability of the system and for making rescheduling decisions. This paper is, in particular, concerned with demonstrating these facts using the model of the NPCC equivalent power system. The emphasis is on the operating procedures and the numerical tools for assessing reliability problems and for optimizing the resources capable of supporting reliability while attempting to minimize costs. We point out that the system-reliability limits are different as the conditions on the system vary. Moreover, this paper points out that these limits are dependent on the operating procedures and numerical methods used. The simulations in this paper point out the need for new generation numerical tools which are more computationally involved than the tools currently used.

Last, but not least, we are fully aware that today's numerical tools require much improvement with regard to their robust performance. There have been many instances of severe operating problems, including the events of August 2003, which could be partly be attributed to the software problems. As the community recognizes the need for more novel and powerful computer-aided tools for facilitating operators' decisions, much effort must be made to ensure their robustness. Given the overall complexity, this is not a very easy task either.

Acknowledgments

The authors greatly appreciate long-term discussions with Dr Eugene Litvinov and Dr Xiaochuan Luo of ISO-NE, as well as help by Dr. Jovan Ilić in running power flow simulations for the NPCC system. This work was supported in part by the U.S. National Science Foundation under award CNS-0428404, and, in part, by the National Energy Technology (NETL) under award entitled "Bundling Energy Systems of the Future". The authors greatly appreciate this financial help. The authors also appreciate the New Electricity Transmission Systems Software (NETSS) Company for providing to the authors its nonlinear AC OPF program.

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