Impact of Security on Power Systems Operation

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Invited Paper

This paper reviews the status of security analyses in vertically integrated utilities and discusses the impact of system security on the operation and the planning of restructured power systems. The paper is focused on the static security rather than the dynamic security of power systems. The paper also discusses assumptions, functions, and calculation tools that are considered for satisfying power systems security requirements. In addition, the security coordination among time-based scheduling models is presented. In particular, real-time security analysis, short-term operation, midterm operation planning, and long-term planning are analyzed. The paper highlights issues and challenges for implementing security options in electricity markets and concludes that global analyses of security options could provide additional opportunities for seeking optimal and feasible schedules in various time scales.

Keywords*—*Contingency analysis, corrective/preventive control actions, generation and transmission planning, maintenance scheduling, power systems security, security-constrained optimal power flow, security-constrained unit commitment.

I. Introduction

The electric power business is rapidly becoming market driven. However, because of the increasingly intimate role that electric energy plays in the national economy, security remains to be the most important aspect of power systems operation which cannot be compromised in a market-driven approach. Recent developments based on the standard market design (SMD) in restructured electric power systems provide an opportunity for electricity market participants, such as generation companies (GENCOs), transmission companies (TRANSCOs), and distribution companies (DISCOs) to exercise least-cost or profit-based operations. In a competitive electricity market, the ISO coordinates the SMD attributes with market participants for satisfying hourly load demand, limited fuel and other resources, environmental constraints, and transmission security requirements [1]–[3].

In competitive electricity markets, customers expect a least-cost and high-quality supply of electric energy, which may require additional investments and more sophisticated operation techniques for enhancing power systems security. The sophistication could in part mitigate severe consequences in the event of cascaded power system contingencies, which might otherwise result in dramatic property and human losses, and severely impede the growth in the national economy.

A. Definition of Power Systems Security

NERC defines reliability as the degree to which the performance of electrical system could results in power being delivered to consumers within accepted standards and desired amounts. NERC's definition of reliability encompasses two concepts: adequacy and security. Adequacy is the ability of a power system to supply consumers' electric power and energy requirements at all times. Security is defined as the ability of a power system to withstand sudden disturbances [4]–[6]. In plain language, adequacy implies that sufficient generation and transmission resources are available to meet projected needs plus reserves for contingencies. Security implies that the power system will remain intact even after outages or equipment failures. This paper focuses on static security requirements of power systems operation.

Four operating states, which include secure, alert, emergency, and restorative states and the transitions between corresponding states were traditionally defined for power systems security [7]–[9]. It is perceived, however, that the absolute security of power systems cannot be unconditionally guaranteed in a complex and highly uncertain market environment when unpredictable and multiple equipment failures or sudden variations of customer demands could cause severe impacts on power systems security.One may examine a deterministic or a probabilistic viewpoint of power systems security. In a deterministic sense, a secure power system should withstand a prespecified list of contingencies. In a probabilistic sense, a secure power system should exhibit a fairly high probability for residing in secure and alert states.

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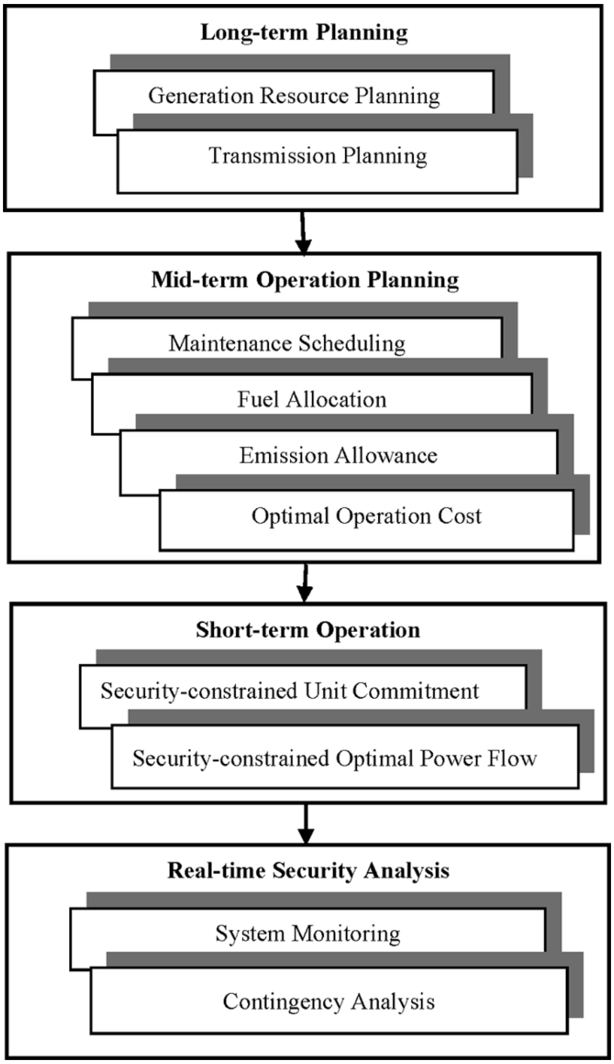

Fig. 1. Hierarchical power systems security analysis.

B. Security Time Scales

Based on possible time scales for analyzing power systems security, we consider the following security analysis frameworks shown in Fig. 1:

- real-time (on-line) security analysis, which maintains the system security in real time;
- short-term (day ahead and weekly) operation, which encompasses security-constrained unit commitment (SCUC) and security-constrained optimal power flow (SCOPF);
- midterm (monthly and yearly) operation planning, which encompasses optimal maintenance scheduling of equipments and optimal allocation of resources (e.g., fuel, emission, and water) for maintaining the system security;
- long-term (yearly and beyond) planning, which encompasses generation resource and transmission system planning for maintaining the system security.

Real-time and short-term operation risks are associated with unexpected failures of power system components and hourly load fluctuations due to sudden changes in weather conditions. Furthermore, short-term operation is exposed to financial risks associated with the volatility of electricity prices. The midterm operation planning risks are associated with the procurement of fuel or the availability of natural resources such as water inflows. Furthermore, midterm operation planning is exposed to financial risks associated with forward electricity and fuel prices. The long-term planning risks are associated with the construction of generating plants and transmission facilities. The financial risks in this case are greater than those of midterm, which could be related to the construction lead time and interest rates.

From the physical operation viewpoint, a proper long-term planning or midterm operation planning could provide a wider range of options for managing the security in short-term and real-time power systems operations. In addition, the power system operation strategies over shorter periods (such as real-time and short-term operation) could yield useful security signals such that the scheduling over a longer time span (midterm and long-term) could be more efficient and practical. In essence, a global analysis of security options could provide additional opportunities for seeking optimal and feasible states in various time scales.

The following sections of the paper discuss assumptions, functions, and calculation tools that are considered for satisfying power systems security requirements in various time scales.

II. Real-Time Security Analysis

The on-line security analysis is performed by energy management systems (EMS) at power system control centers. On-line security analysis encompasses two main parts: system monitoring and contingency analysis. System monitoring is exclusively a real-time function, but contingency analysis, which is discussed in this section, is also used in off-line applications considered in other time scales.

A. System Monitoring

A power system is monitored through the supervisory control and data acquisition (SCADA) system installed at control centers. SCADA collects real-time data from remote terminal units (RTUs) installed in substations and power plants and distributed throughout the power system. SCADA scans RTUs at a frequency of about 2–5 s. The data acquired typically include watts, vars, volts, amps, kilowatt hours, frequency, circuit breaker status, and tap changing and phase shifting transformer settings. These data are transmitted to the system control center and stored in the SCADA/EMS real-time database. The system operator then monitors and controls the system in real time with the help of a state estimator (SE) program [10]–[14]. The SE periodically computes an estimate of the operating state of the subnetwork of interest, which is almost always a part of a larger network. For the purposes of contingency analysis, the complete model computed by SE consists of the monitored subnetwork and an external equivalent [15]–[18] that approximates the effects of the surrounding global network. To minimize errors in establishing a network model of the system state, the set of measurements is made as redundant as practicable. At best, SE produces only an approximate model of the true operating state of the system.

Many different SE algorithms have been proposed, but only a few are at production stage. The most commonly used algorithms are variants of weighted least squares estimation, which is assumed here. The SE gain matrix is built from Jacobian elements of the polar power flow equations. Its dimension is the number of buses in the SE model. But its sparsity structure is much denser than that of the Jacobian matrix and it is numerically very ill-conditioned, making it necessary to use special techniques such as orthogonalization to factorize it. The SE algorithm is iterative and its solution time varies unpredictably with each new measurement set. Convergence of SE is uncertain, making the robustness of algorithm important. Equally important, and directly related, is the ability to identify and remove bad data, which, if not removed, can severely degrade estimation accuracy and prevent convergence. The most damaging and difficult to identify bad data items are incorrect switch statuses. A completely reliable bad data processor has yet to be developed. Each cycle of SE starts with an observability analysis of the SCADA measurements to determine how much of the state of the monitored subnetwork can be estimated. Unobservable parts are made observable by introducing pseudomeasurements.

All known SE algorithms have shortcomings, particularly in bad data identification and robustness. Some shortcomings cannot be overcome by better SE algorithms. The periods of measurements in a SCADA scan are not synchronous, causing significant time skew errors, which could be remedied only by costly improvements in communications and other special hardware. The impedances of lines and transformers used in the SE model are usually taken from power company data files that are not very accurate. Improving network data accuracy would be a major undertaking. Some inaccuracy results from the use of a positive sequence model for the unbalanced three-phase system. The causes of these inaccuracies could be mitigated to some extent, but it would be costly and difficult.

SE serves several functions in the EMS. Its most important function at present is providing information on system operation directly to operators to aid them in taking correction actions. The quality of on-line security analysis and system operation is directly affected by the speed, accuracy, and reliability of SE.

B. *Contingency Analysis (CA)*

CA is performed on the SE network model to determine whether steady-state operating limits would be violated by the occurrence of credible contingencies. CA generally consists of two parts: contingency selection and contingency evaluation. The number of potential contingencies at any moment in a large-scale power system is very large and the time window for system operators to analyze trouble spots and take appropriate preventive (precontingency) and corrective (postcontingency) actions is quite limited. If the contingency selection is too conservative, the time for its analysis could be too long; if the selection is not conservative enough, critical contingencies that could cause constraint violations or catastrophes could be missed. Thus, a good contingency selection scheme followed by contingency evaluation for a set of selected contingencies must be executed for proper control actions.

CA is further burdened by recent requirements for monitoring flowgate violations. A flowgate is a specified group of lines in the network. Each flowgate has a limit on the algebraic sum of real power flows in its lines. Violations of flowgate limits have to be corrected the same way as violations of individual line flow limits.

Ideally, an ac power flow solution should be computed for each contingency case, but this would take far too long. Using a shortcut, CA could limit ac power flow solutions to a relatively small number of predefined contingencies that have been determined to be the most likely to cause violations. Because of its speed, almost all CA algorithms now use the fast decoupled power flow (FDPF) algorithm [19] to obtain complete and accurate solutions of contingency cases.

The earliest, and still widely used, method of CA employs line outage distribution factors (LODFs) [20], [21] to determine the effects of contingent line outages. The LODFs for a specified contingent line outage are the incremental real power flows in monitored lines caused by the outage of contingent line with a preoutage active power flow of one unit. Thus the incremental flows in all monitored lines caused by the outage of a contingent line with any given preoutage flow can be computed very rapidly from the contingent line LODFs.

In large networks, magnitudes of a large proportion of LODFs for each outage are negligibly small and therefore usually omitted. Efficiency could be further improved by applying sparsity-oriented localization techniques [22]–[25] that compute and process only a relatively small number of LODFs that are large enough to have significant effects in CA problems. A serious shortcoming of LODFs is that the dc power flow on which they are based provides no explicit information on bus voltages and reactive power. The only way to compute these effects accurately is by an ac power flow solution. In fact, the dc power flow has poor accuracy even in computing the incremental real power flows. It is used only because of its speed.

1) Contingency Selection: To reduce the computer time as systems continue to grow increasingly larger, the list of potential outage contingencies for CA could be selectively reduced by engineering judgment before submitting it to CA for further automatic selection. And the list of contingencies to be monitored for violations could similarly be reduced beforehand to further decrease the computational effort. Automatic contingency selection methods [26]–[28] fall into two stages: screening and ranking.

A common screening method is to use the results of the first iteration of FDPF for each contingency case. Tests and experience indicate this is not a very reliable selection method. Two iterations are somewhat better, though they take twice as long and still do not provide useful information on the effects on reactive power sources.

Another screening approach is by bounding [22], [23], [29], which explicitly exploits localization. The effects of a line outage diminish rapidly with electrical distance from the outage and, beyond a certain tier of buses surrounding the outage, become negligibly small for contingency analysis purposes. For each contingency case, the bounding method identifies the boundary tier and computes the dc power flow solution for the contingency in the bounded subnetwork. At this point, the dc power flow solution for the bounded network has been completely computed and is then used to check for line flow violations and to screen the contingency. As now used, the bounding approach requires no setup calculations, is performed on the fly for each new case, and provides maximum flexibility for contingency selection. The approach has been extended to ac network analyses and has potentials for improving CA beyond what was explored previously.

Selection is performed by various ranking schemes which compute a scalar performance index (PI) for each contingency derived from the dc or FDPF solution for the contingency. The assumption in these ranking schemes is that the magnitude of PI for each contingency is a measure of likelihood that it will cause line overloads and violations of bus voltages and reactive power sources. For instance, the MW-PI for each contingency is a summation of terms equal to the number of lines in the network. Each term is a function of the incremental power flow in one of the lines and its flow limit.

The efficiency of PI ranking methods in large networks could be improved by the localization techniques suggested above for LODFs. Only the incremental line flows within a certain easily determinable subnetwork around the contingency have a significant effect on PI results, and only these elements need to be computed and processed in PI ranking.

Once contingencies are screened and ranked, a selected number of contingencies are evaluated and possibly considered for security control actions. Power system solutions are prescribed based on control actions until no violations are encountered in the case of contingencies. At this point, CA is terminated.

2) Contingency Evaluation (Preventive and Corrective Actions): Once contingency violations are identified, the system operator embarks on determining control actions that could partially alleviate or totally eliminate their threat. The control actions range from adjusting control transformers, changing the network configuration, and modifying the economic schedule of units to a precalculated set of load-shedding alternatives. It is customary for a system operator to obtain decision support by running the EMS static security analysis. However, it is usually more difficult to achieve credible decision support from EMS for the dynamic security analysis of power systems.

The immediate goal is to continue with improvements in the computation of preventive and corrective control actions to assist dispatchers in decision making. The primary tools for achieving this goal are programs for solving various definitions of SCOPF problem. Reasonably satisfactory SCOPF solution methods [30]–[32] have been developed for some problems and better ones are constantly being sought. SCOPF programs are not yet used for computing system control actions in real time, but operators in making decisions about control actions are increasingly using them interactively. The trend is toward expanding their role.

The preventive and corrective control actions for managing contingencies in SCOPF represent a tradeoff between economics and security in restructured power systems. A preventive dispatch for *uncontrollable* contingencies is included in the precontingency (i.e., steady state) solution of SCOPF for maintaining the economics and the secure operation of a system in the event of contingencies. However, the preventive dispatch is conservative and could be expensive and even infeasible for potentially dangerous contingencies. The corrective actions represent postcontingency control actions for eliminating system violations. Such contingencies are referred to as *controllable* contingencies.

The engine of SCOPF is the basic OPF problem, for which many solution methods have been developed. In one of the leading approaches, based on variants of the Newton power flow algorithm, contingency constraint violations obtained from CA are entered into the base case problem, which is then solved in the usual way to enforce them in the base case. The alternative approach uses LP-based methods [33]. Although both approaches enforce the violations identified in a cycle of CA, they do not guard against new contingency violations produced by control actions. To check for new violations, it is necessary to repeat the CA. This additional iterative loop makes SCOPF much more costly than OPF. However, if SCOPF is unable to meet the system security, load shedding will be implemented as an emergency control alternative.

III. Short-Term Operation

For a secure supply of electricity, the system security has to be considered in the short-term operation. The short-term operation is regarded as an enhanced alternative for maintaining the real-time security [59]. In the day-ahead market, participants submit their hourly and block generation offers to the ISO, which calculates a security-based hourly generation schedule (SCUC) and dispatch (SCOPF) for supplying hourly loads. The generation schedule is made available by the ISO to corresponding market participants. The market participants could use the ISO's market signals for reconsidering their proposed offers on generating resources, which includes signals on LMPs and transmission congestion. An acceptable security-based economical solution can be reached by the ISO in cooperation with market participants if the day-ahead market is healthy and robust.

Fig. 2 presents the correspondence between the ISO and main market participants. For the purpose of this presentation, we assume loads are price takers. This figure shows the coordination between SCUC and the SCOPF, which is further elaborated in Fig. 3.

Fig. 3 depicts the interaction between SCUC and SCOPF for the day-ahead security analysis in the short-term operation. The SCUC (Loop A) is composed of a master problem (UC) and a subproblem for transmission security analysis at steady state. The steady-state transmission security analysis utilizes the master problem's UC solution and transmission

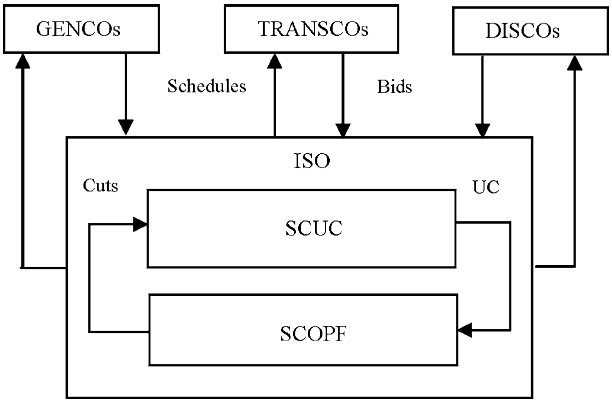

Fig. 2. ISO and main market participants.

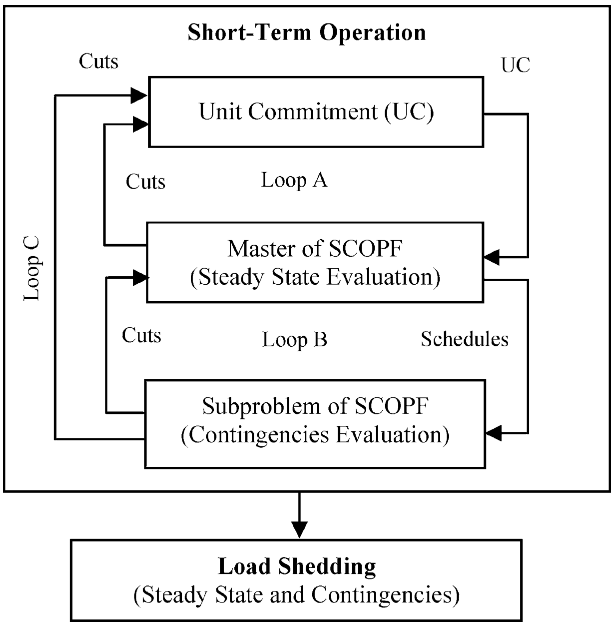

Fig. 3. Short-term operation for security.

flow violations are eliminated by traditional SCOPF control strategies (e.g., adjusting control transformer settings and modifying real power generation dispatch). If transmission security (i.e., transmission flows and bus voltages) violations are not mitigated in the subproblem, Benders cuts will be added as constraints to the master problem for the next calculation of UC [34]. This cut represents interactions between real power generation and system violations. The iterative process between UC and the steady-state ac transmission security solution (Loop A) will continue until the SCUC solution is converged.

SCOPF (Loop B) in Fig. 3 simulates ac contingencies and prescribes preventive and corrective control actions for maintaining the transmission security in the day-ahead market. The ac contingency dispatch represented by Loop B minimizes the cost of short-term system operation at steady state while satisfying the transmission system security, fuel, and environmental constraints at steady state and contingencies. The master of SCOPF is represented by the subproblem of SCUC in which we analyze the steady-state security. The subproblem of SCOPF examines the viability of the steady-state solution in the case of contingencies and possibly modifies the steady-state solution to maintain transmission security.

If SCOPF fails to eliminate violations in the case of contingencies, Loop C in Fig. 3 will be executed to recommit generating units by updating the UC solution. Load shedding in Fig. 3 will otherwise be utilized to prevent the spread of disruptions in power systems when both SCUC and SCOPF fail to maintain the system security at steady state and contingencies.

The components of the short-term operation model in Fig. 3 are discussed in more detail as follows.

A. *Optimal Generation Scheduling for Managing Security*

1) Unit Commitment (UC): Because of peak and off-peak periods in the generation scheduling horizon, uneconomical generating units which are typically scheduled for supplying peak loads should be shut down at off-peak hours to minimize the constrained economic dispatch of generators. In other words, short-term UC refers to the optimum strategy for scheduling generating units. UC determines a day-ahead (or weekly) schedule for minimizing the cost of fuel for supplying electric power and starting-up/shutting-down generating units while satisfying the prevailing constraints listed below:

- hourly load balance;
- hourly generation bids;
- system spinning and operating reserve requirements;
- minimum up and down time limits;
- ramp rate limits of units;
- generating capacity constraints;
- startup and shutdown characteristics of units;
- fuel and multiple emission constraints;
- bilateral contracts;
- must-on and area protection constraints.

The UC solution provides the hourly generation schedule for supplying the system demand and meeting the security margin. The hourly generating reserve schedule could supply unexpected changes in system demand and contingencies for satisfying operating constraints.

2) Computational Aspects of Unit Commitment: Mathematically, UC is a nonconvex, nonlinear, large-scale, mixed-integer optimization problem with a large number of 0–1 variables, continuous and discrete control variables, and a series of prevailing equality and inequality constraints. Various optimization techniques, such as enumeration, priority listing, dynamic programming (DP), Lagrangian relaxation (LR), mixed-integer programming (MIP), and heuristic methods (genetic algorithms, artificial neural networks, expert and fuzzy systems) have been proposed for achieving a near optimal solution and minimizing the production cost, while satisfying the physical constraints. However, perceived bottlenecks including the enumeration's calculation burden, DP's high dimensionality, and the heuristic solution's fine-tuning are barriers to practical applications. With the development of improved optimization techniques, LR and MIP are more widely applied for solving generation scheduling problems. In this paper, we confine our discussions to LR and MIP techniques for solving UC.

a) LR: The LR method applies the dual optimization technique to a nonconvex UC problem with discrete variables. The method determines ON/OFF periods of thermal generating units. In addition, it determines the economic dispatch of committed generating units to meet the hourly demand and reserve so that the total operating cost is minimized while satisfying the operating constraints.

The basic idea for applying LR is to adjoin coupling constraints (e.g., power balance, reserve requirements, fuel and emission limits) to the objective function by using Lagrangian multipliers [35]. In LR, unless a proper modification of multipliers is ensured in every iteration, unnecessary commitment of generating units may occur, which may result in higher production costs. These difficulties are often explained by the nonconvexity of this type of optimization problems due to discrete commitment variables and start-up costs.

The relaxed UC problem is decomposed into subproblems for individual generating units. So the solution of UC is obtained by solving smaller subproblems. Possible states of individual units constitute a state space for possible strategies in which forward DP is used to search the optimal strategy.

The principal advantage of applying LR is its computational efficiency. According to the theoretical analysis and our experience, the execution time will increase linearly with the size of the UC problem. The LR method allows the utilization of parallel computing techniques for single UC subproblems with a remarkably small CPU time. However, in order to obtain a fairly optimal commitment, Lagrange multiplier adjustments have to be skillfully managed. In addition, the LR method could encounter difficulties when solving more complicated system constraints. The inclusion of a large number of multipliers could render the UC optimization more difficult and even impossible to solve as the number of constraints grows.

The performance of LR is enhanced dramatically by augmentation [36], [37]. To implement augmented LR, quadratic penalty terms associated with load balance equations are introduced into the Lagrangian function. Since the quadratic term is not separable, a linearization technique is employed in the augmented LR method. The augmentation method could help identify the proper adjustment of multipliers for improving the convexity of the UC problem and the convergence of the LR algorithm.

b) MIP: When solving large-scale UC problems, the MIP's tremendous computation burden and even infeasible convergence due to a large umber of 0–1 variables are the main obstacles for applying the MIP approach. However, with the availability of more advanced MIP techniques, such as branch-and-cut, which combines branch-and-bound and cutting plane methods, there is a growing interest in the application of MIP to solving UC. Once we formulate and represent UC constraints in the MIP format, the solution can be sought by engaging a standard MIP package such as CPLEX, Xpress, OSL, LINDO, and so on [38]–[40].

The MIP method could obtain a more optimal solution than the LR method. In our 1168-bus test system with 169 units, the total operation cost of the LR-based solution is reduced by about 3% when applying MIP. This benefit provides wider applications of MIP method in the power market environment. In addition, it could be easier to add constraints to the MIP model and obtain an optimal solution without involving heuristics, which could dramatically speed up the development of UC program and facilitate its applications to large-scale power systems. The main disadvantage of MIP is still its computational complexity when applied to large-scale UC problems, especially with a large number of identical generating units in a power system. However, the application of parallel processing to MIP, which will require additional hardware, could soften the computation burden.

3) Hydrothermal Coordination Strategy: The hydrothermal scheduling has been studied extensively due to the excellent scheduling performance of hydro units including its minute generation cost, fast response, abundance of water as a renewable resource in numerous regions of the world, and environmental friendliness. Meanwhile, hydrothermal scheduling could be more complex than that of thermal systems, since hydroelectric plants are coupled both electrically and hydraulically.

Various numerical algorithms considered the hydrothermal scheduling in two separate stages. The hydro problem was solved at the first stage to optimize hourly hydro production. The thermal commitment and dispatch was optimized at the second stage based on first-stage decisions. This two-stage approach could introduce a suboptimal solution [41].

One of widely used hydrothermal scheduling algorithms decomposes the problem into two subproblems, a hydro subproblem and a thermal subproblem, and solves these two subproblems iteratively. The hydro subproblem finds its optimal schedule for maximizing the profit based on initial marginal costs of thermal units; the hydro schedule is then subtracted from the total system load, and the thermal subproblem is executed for calculating a new marginal cost, which is used as a price signal for the next iteration of the hydro subproblem. This solution algorithm is straightforward [42], [43]. However, the hydro subproblem relies on the solution of the thermal subproblem for price signals and could encounter computational difficulties when the thermal subproblem is infeasible. This situation can particularly occur in predominantly hydro systems. To overcome the shortcoming associated with the classical hydrothermal coordination algorithm, we consider a coordination algorithm in which subproblems are solved in parallel by applying Lagrangian relaxation. With a set of initial Lagrangian multipliers, the commitment of single thermal and hydro units is calculated. Accordingly, the algorithm compares the total generation with the system load and updates the multipliers. Network flow programming (NFP) and MIP techniques could be applied for solving the hydro subproblem [44]–[46]. Since all subproblems are used in updating Lagrangian multipliers, this algorithm can effectively reduce the chance of getting infeasible solutions.

B. Interdependent Features of Power Generation and Transmission for Managing Security

1) Interdependency of Generation Resources for Managing Security: Generation resources inevitably play an important role in maintaining the power systems security. The unbundling of the electricity sector and the impetus of competition have resulted in new technologies in power generation, which reduce pollution, increase efficiency, and lower the cost of supplying competitive loads. These technologies often apply to conventional (coal, oil, gas, hydro, nuclear) as well as to unconventional (solar, wind, fuel cells, geothermal, tidal, biomass, and cogeneration, which captures waste heat for energy) sources of energy.

For instance, combined cycle units with high efficiency, fast response, shorter installation time, and environmental friendliness could flexibly meet rapid changes in the competitive electricity market, which could considerably improve the power system's ability to withstand the risk of disruptions in the case of massive contingencies [47], [48]. Fuel switching units, which switch from natural gas to other types of fuel at peak hours and at high demand seasons for natural gas, could conceivably hedge short-term price spikes of natural gas for supplying electricity demand. Fuel switching/blending options could partially mitigate upward price volatility of electricity and maintain a more secure and healthy operation of electricity markets [49]. Renewable and distributed generating units could be utilized at load centers for promoting energy conservation and efficiency, reduce the dependence of electricity infrastructure on coal, oil and gas infrastructure systems, and enhance the security of electric power systems [50], [51].

2) Interdependency of Transmission Systems for Managing Security: In order to provide a more secure supply of power to customers, regional power systems are interconnected via tie lines to form multiarea power systems. Interconnection promotes the interdependency of regional systems, which could trade energy with their neighboring systems for security and economical purposes while satisfying physical and financial constraints. However, such interdependencies may also lead to widespread disruptions in power systems operation due to cascading outages. The recent blackout in the northeastern region of the United States exhibited such cascading events among interdependent power systems.

Power transmission equipment, such as tap-changing transformers, phase shifters, flexible ac transmission systems (FACTS), controllable series capacitors, switchable lines, and so on play an absolutely key role in transferring the least-cost electric energy from suppliers to customers, implementing optimal controls of power systems, and guaranteeing the transmission system security. Tap-changing transformers could link neighboring systems with different operating voltages and maintain voltages within their limits for security purposes. Phase shifters, controllable series capacitor, and FACTS are often applied to control power flows and to enhance the available transfer capability (ATC) of transmission lines [52]. FACTS can alleviate transmission flow congestions, facilitate the power transfer through constrained transmission systems, and reduce load curtailment requirements.

These transmission facilities are to be utilized more efficiently in the restructured electricity market to enhance the power systems security.

3) Interdependency of Energy Supply Infrastructure for Managing Security: Available, affordable, and clean natural sources of energy (including gas, water, and renewable sources of energy) are generally viewed as a prerequisite for economical strength in industrialized societies. The interdependency of primary energy supply infrastructure and electricity could enhance the social sustainability of energy infrastructure.

However, the interdependency could inevitably result in a new electricity risk on a significantly large scale associated with the security of the primary energy supply infrastructure. For instance, competition in electricity markets, advent of more efficient combined cycle units, and environmental concerns have necessitated a more extensive gas supply and transmission infrastructure, which could significantly increase the vulnerability of gas pipelines from the security viewpoint and complicate the monitoring and control of electric power systems. The limited gas supply or interruptible gas contracts may reduce the power generation of a gas-fired generator without dual fuel capability. An interruption or pressure loss in gas transmission systems could lead to a loss of multiple gas-fired electric generators, which could dramatically jeopardize the power systems security. Outages in gas transmission and inconsistent strategies for control, monitoring, and curtailment in the energy infrastructure could further constrain the power system operation and even lead to additional outages [53]. It is apparent that more extensive security analyses are needed for the modeling, monitoring, and simulation of the primary energy infrastructure system when considering the security of electric power systems [54], which will not be discussed further in this paper.

C. Control of Transmission Flows by SCUC and SCOPF for Managing Security

The ISO improves the system security by taking over the control of transmission system. Transmission security constraints in SCUC could be replaced by penalty variables that appear directly in the Lagrangian function of UC [55]. In other words, transmission constraints are relaxed by introducing multipliers in the objective function of UC. The addition of multipliers could make it more difficult to seek the optimal UC solution as the number of constraints becomes larger.

Transmission flow violations at steady state could also be mitigated by solving a dc network security problem [56]. However, the dc solution does not consider bus voltage violations or whether there is a feasible distribution of reactive power in power systems. Although, the dc solution could suffice for midterm and long-term planning, discussed later, the reactive power distribution for managing the steady-state voltage security should not overlooked in the short-term operation. Otherwise, the optimal generation scheduling solution could result in an insufficient security margin and higher risks for real-time operation. Note that real power controls might indeed help mitigate reactive flow violations (e.g., bus voltage limits) which could not be relieved by adjusting reactive power control means alone.

In a more effective scheduling model, transmission flow and bus voltage violations are checked in the SCUC subproblem based on committed power generation, phase shifters, tap-changing transformers, and other control devices [57], [58]. In Fig. 3, the following constraints are included in the subproblem of Loop A for transmission security evaluation:

1) real and reactive power balances;
2) transmission flow limits;
3) bus voltage limits;
4) real and reactive power generation limits;
5) limits on capacitor adjustment;
6) limits on transformer taps and phase shifter angles.

In order to overcome the perceived shortcomings of the decoupled power flow solution, a full Newton method could be proposed to solve the subproblem [59]. Thus, more stringent generation and network constraints could be imposed to reflect SMD features in restructured power systems.

If the steady-state transmission violations persist based on the solution of subproblem in Loop A, Benders cuts are formed and added as constraints to the master problem (UC) for calculating the next iteration of UC. The mitigation of violations will result in the final SCUC solution. We execute a dc flow initially in the SCUC subproblem in order to get a better initial state and improve the performance of SCUC with ac constraints.

In the case of contingencies, preventive and corrective control actions are considered similarly in Loop B of Fig. 3, as discussed before.

D. *Load Shedding for Managing Security*

The load-shedding approach presented in Fig. 3, which is regarded as the last resort for maintaining security will add virtual generators at load buses where load shedding is allowed [60]. The effect of virtual generators is to shed local loads for removing violations at steady state and contingencies. Load shedding at a substation could represent several load curtailment contracts.

IV. MIDTERM OPERATION PLANNING

Midterm operation planning for maintaining security (see Fig. 1) could encompass the optimal maintenance scheduling of GENCOs and TRANSCOs and the optimal allocation of natural resources (e.g., available fuel and emission allowance for thermal units, water inflows for hydro units, and solar and wind conditions for renewable energy). The midterm operation planning solution is coordinated with the short-term operation solution for system security purposes.

Midterm operation planning intends to satisfy the following requirements:

- enhance the power systems security based on limited generation and transmission equipment;
- optimize the allocation of limited natural resources;
- extend the life span of generating and transmission units;
- prolong investment costs for adding new facilities;
- reduce operation costs for supplying competitive loads.

The total cost of midterm operation planning could be divided into production and maintenance costs. The production cost of a GENCO is a function of fuel usage for thermal generating units and other operation costs. The maintenance costs of GENCOs and TRANSCOs could be minimized when planned outages are scheduled according to seasonal load durations and the availability of resources and manpower.

It is customary to assume that the generating unit maintenance cost is a convex function and there is an optimal maintenance schedule for individual generating units. It is reported that the difference between the most expensive and the least expensive generating unit maintenance schedules is about 0.1% of the expected production cost, which is rather substantial for a large-scale power system. However, the minimization of cost in midterm operation planning could create a substantial barrier on system security when available generation resources and transmission facilities would be limited during the maintenance season.

A GENCOs' midterm objectives are to extend the life span of existing generating units through proper maintenance and to optimize competitive payoffs by trading energy with the market. A TRANSCO's midterm objectives are to maintain transmission security through proper maintenance and to optimize competitive payoffs by wheeling energy. The ISO's responsibility is to guarantee the system security and leave out participants' payoffs as a security constraint. As competitive objectives and constraints of market participants could be conflicting, their respective strategies for maintenance optimization could be quite different. Therefore, it could be impractical to seek an all-encompassing objective for participants' optimal maintenance scheduling in a secure power system environment.

Although applying a strategy similar to that of short-term operation by simply extending the number of scheduling intervals could optimize the system security in midterm operation planning, the high dimensionality of midterm problem could render the optimal solution infeasible. Note that the short-term operation (days or weeks) could impact midterm operation planning and the overall system security when considering limited resources, transmission facilities, and emission allowance. Consequently, it could be appealing to the midterm problem to develop a closer coordination strategy between midterm operation planning and short-term operation solutions.

Analytical methods proposed in the literature [61]–[68], for the coordination between midterm and short-term problems, focus mainly on fuel allocation constraints. Generally, contractual requirements such as take-or-pay, and supply chain limits such as limited gas pipeline capacity, could represent fuel consumption constraints. References [61] and [62] used a network flow algorithm to solve the fuel dispatch problem and applied a heuristic method to unit commitment. However, as generation constraints become more complicated, such heuristic solution strategies could fail. Decomposition is a practical scheme which divides the midterm problem into a master problem and several small-scale subproblems and develops a coordination strategy between the master problem and subproblems. Both primal (via resource targets) and dual (via pseudo-resource dispatch prices) approaches could be considered for the solution of decomposition problem [63].

The basic idea of the primal method for the coordination between the midterm and short-term problems is that the midterm fuel consumption limits are allocated to a sequence of fuel consumption constraints that are used directly by the short-term system operation scheduling. The short-term solution would feed back adjustment signals for the reallocation of midterm fuel resource constraints. The reserve capacity was used in [64] as a coordination indicator between the midterm fuel allocation and the short-term optimal operation. The midterm solution was updated if the available reserve capacity at any planning interval was less than a minimum threshold. Reference [65] used the cumulative energy supply mismatch representing daily planned energy and the actual daily supply of energy as a coordination indicator. If the cumulative error exceeded a prescribed value, the midterm optimization would be carried out further.

A lower pseudo-fuel dispatch price, which differs from contract price, could result in higher fuel consumptions and *vice versa*. So the dual method was introduced for the coordination between midterm and short-term problems. In this price-based coordination approach, the calculation of a pseudo-fuel dispatch price is the key task and fuel consumption constraints will not be taken into account at the short-term solution stage. Reference [66] used a linear fuel dispatch problem to obtain fuel dispatch prices. In addition, an adaptive fuel allocation decision was implemented in [67] to dispatch power generation by applying pseudo-fuel dispatch prices which were conditional on past realizations.

In this paper, a possible framework for the coordination problem is shown in Fig. 4 [68]. The ISO accepts participants' proposed maintenance schedules and optimizes the maintenance and operation cost while satisfying system security constraints.

The midterm operation planning algorithm in Fig. 4 is based on the following primal procedure.

Step 1) The optimization of MP2 is viewed as a discrete optimization with maintenance scheduling decision variables. MP2 encompasses numerous maintenance constraints for generating resources and crew availability.

Step 2) Based on the proposed maintenance schedule, an allocation subproblem (SP2) for limited fuel and emission allowance is considered to calculate their upper limits at each time interval of SCUC (e.g., one week). In addition, contract requirements on fuel usage and emission allowance are included in SP2. Accordingly, shadow prices of limited resources in SP2 are fed back to MP2 for the next iteration.

Step 3) The ISO's transmission security subproblem (SP1) is executed based on the given optimal maintenance schedule and allocation of fuel and emission allowance. If any system violations exist, an infeasibility cut will be introduced to MP1 for the next iteration.

Step 4) Once the optimal maintenance schedule and the optimal allocation of limited resources are calculated based on transmission security, a short-term SCUC will be executed. The penalty prices calculated by LR for each limited resource will be introduced to the midterm operation planning for recalculating the optimal maintenance schedule and resource allocation.

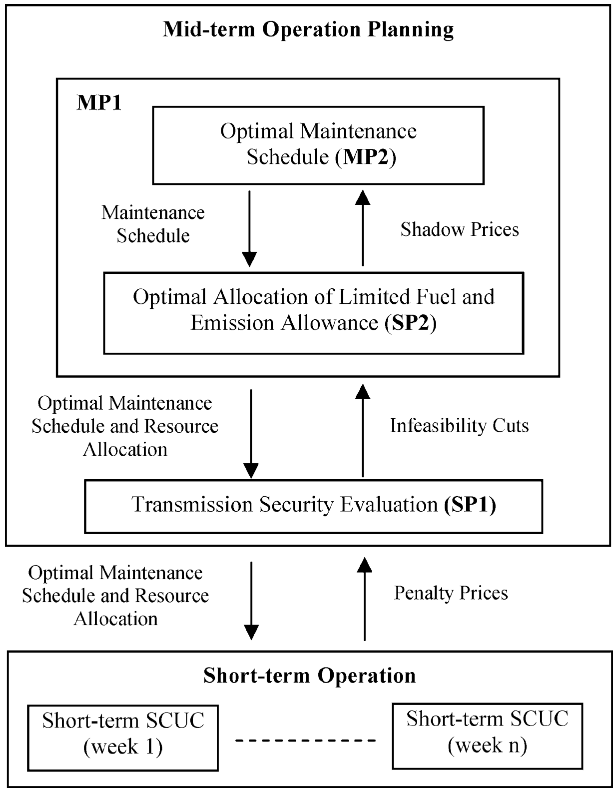

Fig. 4. Midterm operation planning for maintaining security.

Considering the water inflow distribution at each interval in the midterm operation planning problem, [69] showed that different forms of composite thermal cost functions can lead to the same optimal hydro production schedule. Consequently, a subproblem could be added to the model in Fig. 4 for maximizing the profit of hydroelectric units based on daily/weekly energy requirements of the system. The approach in Fig. 4 will make it possible for hydroelectric units to optimize their schedule without acquiring any information on thermal unit cost functions.

V. LONG-TERM PLANNING OF GENERATION AND TRANSMISSION FACILITIES

A. *Impact of Security on Generation Resource Planning*

It is conceivable that electric utility restructuring provides challenging options for generation resource planning in competitive electricity markets. GENCOs including IPPs, QFs, EWGs, and foreign utilities could invest independently in the generation expansion. In the mean time, transmission system security is challenged as GENCOs and other market participants make their investment decisions based on profit maximization. Indeed, the conflict between *economics* and *security* is inevitable in the restructured electricity planning.

In electric utility monopolies, the least-cost operation within a prespecified level of system security was the principle for applying conventional integrated resource planning algorithms [70]. Accordingly, conventional optimization techniques including dynamic programming [71], decomposition method [72], [73], fuzzy set theory [74], and genetic algorithm [75] were successfully applied to multiobjective planning problems. However, in electricity markets, GENCOs' objective for generation resource planning is to maximize expected payoffs over planning horizons, while a secure operation of competitive power systems is sought by the ISO through the cooperation among market participants. For instance, game-theoretic models could be applied to generation resource planning with perceived difficulties for obtaining optimal solutions in competitive electricity markets.

A proper generation resource planning algorithm should incorporate market price volatilities in electricity and fuel, annual load growth, fuel availability and transportation accessibility to generating plant sites, different financial loan incentives and construction lead times, construction costs, transmission rights availability and congestion constraints, expected payoff based on predicted market prices, fixed O&M costs, expected operation cost, as well as load curtailment costs as major incentives for deploying new and competitive generating resources in power systems. Generating resource planning algorithms should examine physical sites and markets for new generating units, various unit types and capacities (such as gas, hydro, oil, coal, combined cycle), timing for the addition of new units, steps for the closure or retrofitting of old generators, generation scheduling of potential units, and strategies for the timely returns on investment.

Fig. 5 depicts an optimal long-term generation resource planning algorithm [76]. The application of Benders decomposition algorithm decomposes the generation resource planning problem into a master problem (GENCO) and two ISO subproblems for transmission security evaluation and optimal operation scheduling. The MIP-based master provides an investment plan for generating units based on alternative types of units, potential payoffs for individual units, suitable investment options, and prospective generating unit sites based on proximity to fuel resources (such as gas pipelines).

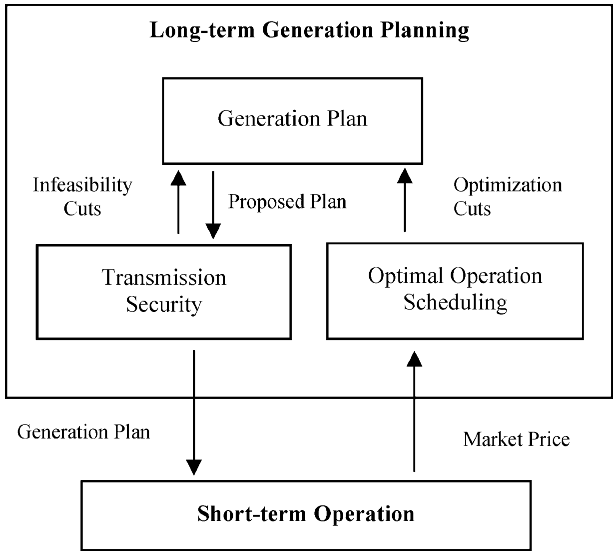

Fig. 5. Long-term generation planning.

Once the candidate units are identified by the master problem, the ISO's transmission security subproblem checks whether the proposed generation plan can meet transmission security constraints (such as the line flow limits and maximum allowable load curtailments). If security violations persist, the subproblem will form Benders cuts that will be added to the master problem for the next iteration of generation planning. Once the security violations are mitigated, the ISO's optimal operation scheduling subproblem will select the one with the maximum payoff among the proposed generation planning options.

In this long-term generation planning algorithm, the coordination between long-term planning and short-term operation is of essence to simulate the pseudo-market price, which is either market-clearing price or locational marginal price. The salient feature of the proposed generation planning algorithm is that it treats GENCOs as independent agents which could compete in a volatile electricity market for maximizing payoffs while the transmission system security is monitored by the ISO.

Due to the volatile nature of electricity markets, uncertainties in operating conditions representing forecasted market price of electricity, load growth, financial risks, equipment availability, and the like are taken into consideration in generation resource planning algorithms. Facing uncertainties, power system planners apply certain techniques such as stochastic optimization [77], [78] to manage the probabilistic nature of generation planning. These proposed solutions are viewed as a tradeoff between economics and secure planning alternatives which could provide planners with a list of alternatives based on expected payoffs and system security in electricity markets.

B. *Impact of Security on Transmission System Planning*

Traditionally, the integrated planning of generation and transmission systems has been the responsibility of vertically integrated utilities under state regulatory oversights [79]–[82]. The common objective of integrated planning models is to find least-cost options for generation and transmission investment, system operation, and curtailment penalty charges.

However, in today's increasingly competitive electricity markets, self-interested players and competitors participate in the planning and operation of power systems. For instance, GENCOs, as independent and for-profit market entities, are freely and actively making plans for generation expansion, which could dramatically impact existing transmission flows and congestions. Customers can also select their own electric energy suppliers based on economics, power quality, and security. As a result, the transmission system planning is facing credible challenges for managing its operation economics and security [83]–[88].

The objective in market-based transmission planning is to maintain system security within an acceptable level while maximizing the social welfare (or minimizing the investment and operation costs). To realize the objective and determine when, where, and what type of new transmission facilities are to be installed, various models and algorithms are introduced [89]–[93] in which the system security remains the most important operation issue. The Monte Carlo simulation is used routinely in transmission planning algorithms [94].

The debate in the competitive electricity market focuses on the entity that should be responsible for transmission system planning. Some stakeholders believe that the transmission operation is regional and transmission planning should be controlled and monitored by regional regulating authorities, such as the regional transmission organization (RTO) [95]. The RTO could define transmission projects which are "essential" for satisfying customer demands and market requirements as expressed by load growth forecasts, new load and generation interconnection requests, long-term transmission service requests, improved operational security, mitigation of local and regional transmission congestion, replacement of old transmission and generation facilities, required operational and economical efficiency, and so on. Among prospective transmission investors, entities which command the least financial payoff and provide the highest level of security in the short-term operation should be rewarded with the rights for establishing and operating new transmission facilities.

It is conceivable that the LMP-based market pricing provides efficient and transparent economic signals for long-term transmission investments to improve the transmission network security and reliability of power supply. Because LMPs reflect the locational value of electricity when congestion charges arise, power grid users could compare long-term congestion charges against transmission investment costs. If accumulated congestion charges begin to exceed the cost of upgrading the transmission grid, then grid users could have an incentive for investing in grid upgrades.

VI. Conclusion

Recent blackouts in the United States and throughout the world provided a growing evidence that certain actions are urgently needed to ensure that the electricity sector will continue to provide secure and affordable energy to its customers. The restructuring of electricity and the creation of self-interested entities such as generating and transmission companies have surfaced many shortcomings of the existing electricity systems in an interconnected network. This paper reviewed some of the existing methodologies for enhancing the power systems security in vertically integrated utilities and proposed alternatives in various time scales for improving the security of restructured power systems. It was discussed in the paper that, from a physical operation viewpoint, a proper long-term planning and midterm operation planning could provide a wider range of options for managing the security in short-term and real-time power systems operations. In addition, power systems operation strategies over shorter periods (such as real-time and short-term operation) could yield useful security signals such that the operation scheduling over a longer time span (midterm and long-term) could be more efficient and practical. This paper concludes that the conflict between economics and security is inevitable in restructured power systems and a global analysis of security options could provide additional opportunities for seeking optimal and feasible states in various time scales.

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