J. Webster (ed.), *Wiley Encyclopedia of Electrical and Electronics Engineering*

POWER TRANSMISSION NETWORKS

The capability of a transmission line refers to its ability to transfer power between its terminating ends. Although many factors affect this capability, one limitation is the line's inherent losses, which are emitted as heat. Unlike pipeline analogies, electric power distribution obeys the physics of Ohm's Law, where power losses are proportional to the square of the current in a given transmission line multiplied by its complex (i.e., real and imaginary) characteristic impedance. Greater line losses relate to less actual power transfer through the line. Losses can be minimized in one of two ways—increasing transmission system voltage levels to decrease the current flow in a given conductor or minimizing or altering the transmission line characteristic impedance to reduce line losses. In either case, minimizing losses is a key component aimed at increasing transfer capabilities through system transmission lines. Phase-shifting transformers, various capacitor configurations, and Flexible AC Transmission Systems (*FACTS*) are applied routinely to relieve these constraints partially.

Because transmission line characteristic impedances are not totally resistive and motor loads contribute to reactive components, voltage support at determined delivery points is often required to maintain proper voltage levels at customer sites. These effects, which also decrease transfer capability, can be minimized by adding capacitor banks at strategic system locations. In addition to reactive effects, alternating currents generated by rotating machines further complicate power transfer capabilities through complex system stability relationships.

System losses, voltage concerns, and stability issues combine to make electrical transmission a dynamic and complicated aspect of electricity generation and distribution. The following sections describe why transmission modeling is necessary, how system operators control daily generation and interchange dynamics to meet the operational demands of a continuously changing electricity network, and what the more prevalent characteristics of electricity transmission are.

Transmission modeling is a necessary component of a realistic electric energy model. Adequate transmission capabilities support both economic system operation and increased system reliability. Therefore, if transmission constraints are neglected when developing a particular model, some very real limitations regarding the economic and operational aspects of the power system are overlooked. The importance of modeling transmission characteristics is illustrated in numerous technical papers and reports about studies being conducted by the Electric Power Research Institute (*EPRI*), universities, and corporate organizations.

Physical Transmission Limitations

A variety of physical transmission limitations dictate the actual transfer capabilities of specific transmission lines. These limitations directly influence the way in which control area operators react in various situations. Such actions can preserve system security, while sacrificing economic dispatch. A proper response by the control area operator to alternative exchange options and system contingencies ensures system integrity and availability. The following considerations represent some of the important physical constraints that influence daily operations:

- *Stability* refers to those generation resources that remain synchronized with respect to each other and system loads.
- *Thermal capacity* refers to the maximum amount of power capable of being transferred without causing thermal (i.e., conductor heating) damage in transmission lines as a result of line losses.
- *Loop flows or parallel flows* occur when the portion of power that flows on lines is not directly related to the contract path.
- *Voltage support* is required to ensure that system delivery points remain within a specified voltage tolerance as network dynamics vary.
- *Dependability of generation and transmission interconnections* is required because a slight change in unit generation can significantly alter the transfer capability of a particular transmission line.
- *Reliability issues* (e.g., first contingency incremental transfer capability, FCITC) refer to the study of the impact of various contingencies on transfer capability.

The ease of modeling these constraints varies greatly. Detailed system knowledge and commercial load flow and dynamic security assessment programs are presently used to model these physical characteristics to derive required base case studies. The results from these studies can be used in more abstract models that cannot rely on access to individual system parameters and operations expertise. Such generalized models can be sufficient to represent desired network characteristics and obtain reasonable and historically valid model results. The methods described later use data derived from dc and ac load flow analysis.

Deregulated Power Systems

The Public Utility Holding Company Act of 1935 (*PUHCA*) erected a barrier for the entry of nonutility generators (*NUG*s) into the electricity generation market. The market monopoly was breached by the Public Utility Regulatory Policies Act of 1978 (*PURPA*). It opened the door for cogeneration and for small power production technology based on hydro, wind, and biomass, allowing them to enter the electricity market without being burdened with PUHCA requirements. Electric utilities retained some avenue through rules that allowed up to 50% ownership share in a qualifying facility (*QF*). Since PURPA, many utilities have established subsidiaries to exploit the potential benefits of participation in QF projects as sources of lower-risk capacity compared to plants directly built by the utility. As a result of PURPA, more than 20,000 MW of QF capacity were brought into operation. The initial purchases, which were based on the avoided cost of the utility, soon gave way to competitive bidding among QFs. The competitive bidding has now expanded beyond PURPA facilities and in many states has become the mechanism for establishing merit among all producers of electricity (utility, QF, independent power, etc.).

Despite the competitive bidding, PUHCA acted as an effective barrier to the entry of many new power producers into the nationwide electricity market. As a result, the National Energy Policy Act of 1992 considers the amendment of PUHCA to promote greater competition in the supply of electric power by creating a new class of wholesale electricity generators who are exempted from the corporate and geographic restrictions of PUHCA. In another major change, the Federal Power Act (*FPA*) was also amended to provide the Federal Energy Regulatory Commission (*FERC*) with the authority to order transmission utilities to wheel power produced by the new exempt wholesale generators (*GENCO*s) if such wheeling is in the public interest and would not impair the reliability of the transmission system. Hence, the door is opened for NUGs and independent power producers (*IPP*s), qualified as GENCOs, to enter the wholesale electric power market. In principle, the competition will be on the production side, whereas network costs will be supplied for and through new monopolies. In fact, competition is not so easy. If power producers are tied together with jointly owned power stations, it is obvious that some strategic company information must be not only exchanged but also questioned by outsiders who desire increased competition.

Since early 1990, owners, operators, and users of interconnected transmission systems in the eastern United States and Canada have been voluntarily convening to discuss interregional transmission issues with the intent of enhancing cooperation and coordination. The participants refer to themselves as the Interregional Transmission Coordination Forum (*ITCF*). The ITCF recognized that significant parallel flow between utilities is inevitable and occasionally burdensome to transmission owners and operators who presently have little or no control over others' transactions and receive no compensation for parallel power flows across their systems. To address this issue, the ITCF formed the General Agreement on Parallel Paths (*GAPP*) Committee to explore the practicality of replacing the single contract path approach with a multiple contract path approach. In such cases, the transmission systems, which are impacted by specific transactions, will be appropriately involved from a contracting, scheduling, and operation perspective. Under the GAPP method, utilities will be compensated for what would previously have been an uncompensated parallel flow; parallel flow will largely become scheduled flow, and all scheduled flows will be priced by the providers of transmission service according to a public posting of their approved rates, whatever they may be. ITCF is planning to have the details of an up to 2-year experiment ready to present to FERC in 1994, which will include how the experiment will be conducted and how results will be evaluated.

Open Transmission Access. Open transmission access promoted the need for determining benefits and problems associated with regional power transfers. Therefore, determining the available power transfer capability to better using the transmission system constitutes an urgent need for electric utilities. Some government agencies have been involved in research concerning this issue. The Department of Energy (*DOE*) has sponsored the national power grid study addressing the benefits to system economics and reliability that can be achieved through more integrated utility planning and operation. In addition, Electric Power Research Institute (*EPRI*) has sponsored several studies related to open transmission access and increased future power transfer. One study considered numerous factors (control software and hardware) that affect transmission line capacity and limit electric power transfer, and a software package was developed to determine transmission line capability. Additionally, a study is planned to determine the actual cost of transmission access.

Nearly all electric utilities in the United States are interconnected in the form of power pools that make up the eastern and western systems. The ability to gain long-term access to wheeling services permits a utility to expand the geographical area from which it can seek new generation sources to meet its own load growth. Potential benefits from enhanced infertility cooperation in system operation and development coupled with arrangements that allow for transmission access and wheeling appear to be significant. To realize these benefits, several options have been presented ranging from the continuation of the present voluntary cooperation through the present voluntary action with federal monitoring and the voluntary regional coordination groups for least cost integrated resource planning to the establishment of regional coordination groups with mandated federal power. No matter what option is followed, the overriding factors for success require adherence to a set of principles to promote fairness, reciprocity, and net benefits to all parties.

Ideally, FERC will decide whether to grant a proposed transmission access to a NUG, which may be an IPP or a cogenerator, based on considerations that the proposed transaction would not unreasonably impair the operational integrity and the continued reliability of the host power systems and that such transactions are in the public interest. An unbiased opinion of these considerations requires refined analyses on the operational, security, and stability aspects of the host electrical system. NUGs may or may not be within the planning scope of transmitting utilities and are considered as nondispatchable by the energy control center coordinating the operation of the transmitting utility. Therefore, electric utilities may have a natural tendency to resist open transmission access as a result of perceived operational burden and potential negative impacts of NUGs on system reliability as well as potential economic impacts. Studies on transmission access have been focused on how NUGs should be charged for gaining access to a transmission network. Methods that can be used to calculate embedded costs of existing facilities, short-run marginal costs (*SRMC*) in system operation and long-run incremental costs (*LRIC*) for system expansion for the purpose of determining wheeling costs are presented in Refs. 24,25,26,27,28,29,30.

There are major factors and concerns that must be considered in open transmission access. Some of these concerns follow:

(1) *Security.* There are many questions as to how power systems security will be handled in open transmission access and among different power system entities. What procedures should be followed if a contingency occurs within the wheeling utility and a transmission line in use by various parties is to be disconnected? Can the transmitting utility be the sole decision maker and proceed to take the line out? Should the proposed control action be evaluated by other affected power systems to make sure that it would not endanger their security? How fast must the communication between different parties be in order to reach a secure procedure for all parties? What is the feasibility of such procedures? If the transmitting utility wants to reduce the amount of power transfer only over a transmission line that is shared with other power producers, then how would the procedure affect the total generation in the other utilities? Should the power generation curtailment be proportional to the existing amount of generated power in those utilities?

(2) *Unit commitment.* When IPPs, NUGs, and utilities are all involved in the process of power generation in a certain area, then how would the unit commitment and short-term power generation be scheduled? What are the major factors that are to be considered concerning whether a power system should generate power or buy it from other available sources?

(3) *Parallel paths.* One of the most significant issues regarding interconnected transmission systems is the operation of unscheduled or parallel power flows. When power is transferred from one utility to another, a path is arranged by contract for delivery of the power. However, a portion of the contracted power actually flows over other transmission lines and through other utility systems. The difference between the contracted power scheduled over an interconnection and the actual flow is known as parallel flow (also called loop flow or circulating flow). The issue, although not new, has received increasing attention over the past decade during which time substantial power transfers among utilities have routinely taken place, often to the reliable limit of transmission systems.

(4) *Spinning reserve.* Because a great deal of wheeling transactions will take place between different parties, who is going to be responsible for maintaining a certain level of spinning reserve? If utilities are to provide the spinning reserve resulting from the insufficient power-generating capability of NUGs and IPPs, then how should they be compensated in an open transmission access environment and how will the required spinning reserve be allocated among different utilities?

(5) *Reactive power wheeling.* Wheeling is the transmission of real and reactive power from a seller to a buyer through a transmission network owned by a third party. The flow of reactive power within the wheeling utility will affect bus voltages and tap changing transformers setting. The concern focuses on the possibility of voltage collapse within the wheeling utility and the effect of this collapse on participating utilities. Another concern is related to an adequate supply of reactive power to all parties in a multiarea power system; the questions center around where to locate var sources and who will pay for them.

(6) *Loss of NUG.* IPPs and NUGs will provide a certain portion of the power generation in the open transmission access environment. The concern is that a NUG or an IPP may enter the market when prices are high and go bankrupt as prices fall. In such cases, who will provide the deficiency resulted from loss of NUGs or IPPs? This scenario is similar to that of a few years ago as saving and loans institutions across the country went out of business. In the power utility example, however, the federal government's assurance will not generate much extra power within a short period of time. What will happen if a number of IPPs supplying a portion of local loads go out of business and the transmission utility cannot come up with additional generating capacity in a short time to supply that extra load (generation expansion planning may be postponed by many utilities as they anticipate NUGs to supply part of the load growth in a particular area). The construction of new facilities may require a great deal of investment and take a long period of time; who will supply the load during this period?

(7) *Coordination.* As a result of increased regional power transfers, the possibility of contingencies and various control actions that can affect the utility's own system as well as other systems may get escalated. Hence, there must be a coordination between all control areas of different systems when a major action from a control area is going to be initiated. The question in this case is, what is the amount of information required within each area and among different control areas to ensure a safe operation through proper coordinations of systems' capabilities?

(8) *Transmission losses.* If a transmission line owned by a host utility is used for simultaneous power transfers caused by different wheeling scenarios, then transmission losses will increase because of these transfers. The question is, how will the transmission utility determine losses caused by each transaction in order to charge different parties accordingly? Will the charge rate be proportional to the amount of power transmitted? Should other methods be used as a result of the nonlinearity of power losses?

It should be emphasized that this list of problems and concerns is by no means complete. These problems are viewed as major problems that need to be addressed whenever open transmission access is mentioned.

California Market Structure. The investor-owned electric utility industry in California will be restructured to allow for wholesale and retail competition beginning in 1998. Under the plan, an independent system operator (*ISO*) will operate, as a single control area, the transmission systems that at present are owned and operated by the three largest utilities in the state—Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Co. (5).

The ISO will be responsible for ensuring that schedules for using the transmission system are feasible, operating the transmission system in real time, and for setting financially with parties who use the transmission system. It will guarantee open access to the transmission grid so that no particular group of market participants—wholesale or retail—is favored.

A separate power exchange (*PX*) will serves as a daily spot market for electricity with publicly posted prices. That is, an auction will be held daily in which bids will be taken for each hour of the next day's operation. The PX and ISO will work together not only to provide competitive generation markets but also to safeguard the reliable operation of the transmission network. Market participants will compete in day-ahead and hour-ahead physical energy and ancillary service market. Generation, load, and out-of state interchange can participate by making bids to the PX. In addition, market players are free to arrange bilateral trades through scheduling coordinators. The next-day market consists of 24 individual hourly markets. Load and generation bids are evaluated each hour, based on bid price. Responsibility for unit commitment (scheduling) resides with those who bid generation and not with the PX, which does perform any unit commitment.

The PX serves to match generation with load and to provide the resultant balanced energy schedules to the ISO. The ISO then evaluates the feasibility of the proposed schedules from a transmission network security standpoint. For the purposes of transmission management, the California network is divided into multiple zones. The ISO identifies the constraining interzonal transmission facilities and allocates their usage to the highest value users. The users of the constraining facilities then pay for the (redispatch) cost of congestion management, as determined by ISO.

Generation resources participate in redispatch process for congestion management by making energy adjustment bids. The ISO selects from among these bids, when required, based on their cost-effectiveness. Minor congestion within a zone is resolved by slight redispatch, with associated costs borne by all schedules within the zone by means of a zonal uplift charge.

In addition to energy in the next-hour and next-day markets, essential ancillary services are bid. These include frequency regulation, reactive support and spinning, nonspinning, and replacement reserves. Black start capability is contracted on an annual basis. The ISO manages real-time energy imbalance by dispatching a supplemental energy source, which bids into the next-hour market. The power exchange and scheduling coordi-

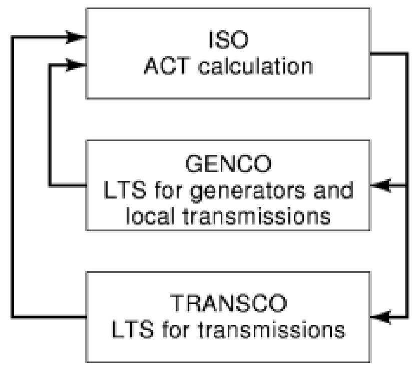

Fig. 1. Scheduling in deregulated power system.

nators communicate with the ISO using Internet-based communications protocols. The ISO also communicates with generators and dispatchable loads using dedicated real-time communications links.

The California model collectively implements the nondiscriminatory open access requirements without the need for any Open Access Same-time Information System (*OASIS*) and transmission providers. In the deregulated environment, there are mainly three players—*GENCO*s (the generating companies), *DISCO*s (the distribution companies), and *TRANSCO*s (transmission providers). The GENCOs are the companies that own the generation and sell the power.

DISCOs are typically companies that buy the power from the GENCOs and sell it to the customers in their area. TRANSCOs are companies which own and operate the transmission networks. The GENCOs and DISCOs enter into negotiations to finalize the power deals. After a deal is finalized, one of the parties must book the transmission capacity so that the power can be "shipped" from the delivery point to the receipt point. This process of reserving transmission capacity is done through the Internet. This brings the OASIS into the picture. It provides the Web interface for checking out the available transfer capacities between two buses and to reserve transmission capacity.

There is an additional entity, which acts as the go-between for a GENCO and a DISCO. That is the Power Marketer (*PM*), a power trader. It negotiates a lower price from the various GENCOs, consolidates the power, and sells it off at a higher price to a DISCO. Conversely, it can combine small demands of various DISCOs and, after consolidating, buy in bulk from a GENCO.

Because all the deals are market-based, there is an entity known as the Independent System Operator, which in charge of the operations of the grid. The ISO takes care that the deals that are finalized and can, in fact, be allowed to go through the system without having any abnormal effects on the grid. In this connection, the following functions of transmission and generation scheduling are identified in Figure 1.

Long-Term Scheduling (*LTS*) and Short-Term Scheduling (*STS*) may be used by GENCOs to schedule generating units and local transmission lines within an area. LTS and STS tools are used by TRANSCO to schedule the availability of major transmission lines. The availability of generating units provided by GENCO and transmission lines by TRANSCO are given to ISO for the Available Transfer Capability (*ATC*) calculation. The ATC is the measurement of the ability of interconnected electric system to reliably move or transfer electric power from one area to another by way of all lines between those areas under specified conditions. If it is found by ISO that the system does not reliably meet certain criteria, then GENCO and TRANSCO are to modify their schedules.

Maintenance Scheduling

The move toward a market competition in the near future is creating more pressure on power companies to choose an optimal maintenance schedule for transmission lines and generating units. This choice must take into account complex cost tradeoffs and constraints that are involved in evaluating the impact of maintenance schedule on GENCO, TRANSCO and DISCO operations. Power companies spend millions of dollars per year on maintenance. Additionally, they must pay for such hidden costs as purchased energy when a generating unit is out and loss of revenue. These hidden costs are attributed to maintenance. The system reliability and operating costs of electric power systems are affected by maintenance outages of generation and transmission facilities (1). Additionally, carefully optimized maintenance schedules could potentially defer capital expenditures on new plants in times of tightening reserve margin and allow critical maintenance, which might not otherwise be done, to be performed. Maintenance scheduling can be a significant part of the overall operation scheduling in a deregulated system.

Generation and Local Network Maintenance. Accounting for the interaction between fuel restrictions, allowable emission, and system constraints greatly increases the complexity of LTS, resulting in a large optimization problem. The LTS problem has discrete decision variables related to maintenance scheduling and continuous variables representing fuel allocations and utilization levels of units. The first objective is to minimize the maintenance cost of generators, the second is to minimize transmission line maintenance cost, the third is to minimize the energy production cost, and the forth is to minimize the cost of energy purchased from outside. The production cost itself is a probabilistic optimization that takes into account the derated capacity of each generating unit. Sets of constraints may be considered subsequently (14,15,16).

Maintenance Window. These constraints represent the maintenance window and include generating units and lines available before their earliest possible period of maintenance and after their latest possible period of maintenance. Additional constraints consisting of crew and resource availability, seasonal limitations, and favorable schedules can be incorporated.

System Emission Limit. In the past, large coal-burning units could be treated as if their fuel consumption was unconstrained, and the only limits on fuel were those imposed by contractual obligations and fuel prices. The Clean Air Act of 1990 further complicated the picture in United States. The emission control makes it more difficult to plan off-line maintenance and on-line fuel allocation. Although emission control has less impact on oil- or gas-burning units, fuel for these units is considerably more expensive and always limited by fuel contracts. The two primary power plant emissions are SO_2 and NO_x, given in our model as a function of unit generations. The emission can be modeled as either linear or quadratic function. In the case of a quadratic function, a piecewise linear emission function can be adopted. Emission caps for certain areas and the total system emission may also be considered.

Network Constraints. Generating units are distributed in different regions and interconnected by transmission lines. Generating unit maintenance should consider transmission forced and planned outages, which may lead to different composite reliability levels for a given maintenance capacity outage. The task of maintenance scheduling involves specifying dates at which manpower is to be allocated to overhaul a major functional element or group of elements in a power system. The maintenance should be scheduled such that the overall system security level is acceptable, costs to the utility are minimized, and all or most system constraints are met. The GENCO's local network can be modeled as either the transportation model or a linearized power flow model. These constraints should represent system operation limits, balance generation and demand, and generating and line capacity limits.

Fuel Constraints. For some utilities, contractual obligations limit the amount of fuel burned at a unit. During the actual operation, units are loaded in decreasing order of operating cost. If the fuel for a particular unit is scarce, then the unit's operating cost will be effectively higher. If the maximum amount of fuel is allocated to that unit in one time period, that fuel may become scarce in some other time period when its availability is even more important. The long-term resource scheduling function observes restrictions that arise as a result of contractual agreements with fuel suppliers. These restrictions include the maximum amount of fuel that can be delivered during the day, month, and the year. These restrictions are represented in fuel constraints (13).

Production Costing. The energy production cost is a function of the amount of fuel burned by a unit. The energy purchased for period t, denoted as F_t, depends on the use of available units to satisfy demand constraints in each time period subject to maintaining reliability above a certain level. We use each unit to its capacity starting with the cheapest unit until the reliability constraint is satisfied (merits order). If there are not enough available units to meet the reliability requirement, then energy purchase from outside is considered.

Solution Methodology. Because of the discrete nature of maintenance scheduling, mathematical programming approaches have fallen into two broad categories: integer programming (branch and bound) and dynamic programming. Integer programming was devised by a number of authors (18,19,20); however, there are some difficulties with this approach. First, the approach cannot consider uncertainties. Second, it may require excessive computational time and memory. To alleviate these problems, some researchers have implemented branch and bound approach in integer programming. In theory, dynamic programming (*DP*) is most suitable to the solution of maintenance problems because maintenance scheduling is a sequential decision process problem. However, the "curse of dimensionality" limits the application of this method. Zurn and Quintana (21) used a successive approximation approach in DP and grouped the units to reduce the state space.

More recently, Benders decomposition (6) has been applied to decompose the problem into a master problem and a series of subproblems. The coordination of master problem and subproblems results in the solution of generator maintenance scheduling (9,10,22,23). The problem can be broken down into three subproblems. There is the maintenance subproblem, operation subproblem, and fuel dispatch subproblem. First, we solve maintenance and operation subproblems using Benders decomposition. This first decomposition is a relaxation of the original problem in that it contains only maintenance window, emission, and network constraints. When this portion of the problem produces a maintenance schedule that meets network constraints (assuming unlimited fuel), the maintenance schedule and unit generation level are then sent to the fuel dispatch subproblem. When this subproblem is solved, fuel cost can be calculated for the master problem. For this strategy to be successful, additional cuts between subproblems must be efficiently generated. Figure 2 is a natural extension of the LTS problem to treat fuel constraints. The trial maintenance schedule from MP1 is used to check the feasibility of fuel constraints over all time periods and to calculate unit fuel price (dual or shadow prices) as necessary. This iteration between MP1 and SP1 problems continues until no further cost improvement is possible and the maintenance schedule satisfies all constraints.

The MP1 itself is decomposed into master problem (MP2) and operation subproblems (SP2). The MP2, which is an integer-programming problem, is solved to generate a trial solution for maintenance schedule decision variables. This master problem is a relaxation of the original problem in that it contains only a subset of constraints that are maintenance window and emission constraints. Its optimal value is a lower bound on the optimal value of original problem. After x_{it} or N_{kt} variables are fixed by MP2, the resulting operation subproblem (SP2) can be treated as a set of independent subproblems, one for each time period t, because there is no constraint across time periods. The set of operation production cost subproblems in SP2 is then solved using the fixed maintenance schedule obtained from the solution of MP2. At each iteration, the subproblem SP2 calculates unit generation level and cost of purchasing energy while satisfying network constraints. SP2 also generates dual multipliers, which measure the change in unserved energy or energy cost resulting from marginal changes in the maintenance schedule. These dual multipliers are used to form one or more constraints (known as cuts), which are added to the master problem MP2 for the next iteration. The process continues until a feasible solution whose cost is sufficiently close to the lower bound is found [see Marwali and coauthors (9,10) for a detailed analysis].

The critical point in this decomposition is the revision of MP2 based on the solution of fuel dispatch subproblem. Associated with the solution of the fuel dispatch subproblem is a set of shadow prices that measure changes in system operating costs caused by marginal changes in the trial maintenance. These shadow prices are used to form a linear constraint, written in terms of maintenance variables. This constraint, known as

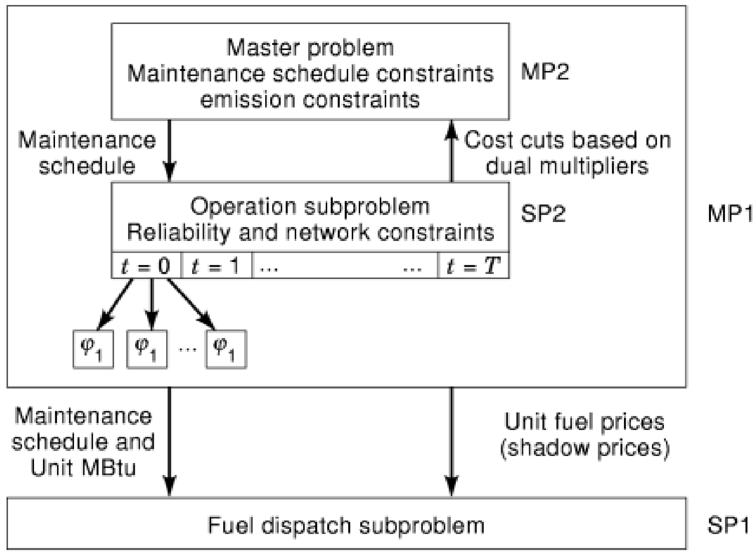

Fig. 2. Long-term scheduling decomposition.

Benders cut, is returned to the maintenance problem, which is modified and solved again to determine a new trial maintenance plan.

Transmission Constrained Unit Commitment

Unit commitment is one of the critical issues in the economic operation of a power system. It determines a unit generation schedule for minimizing the operating cost and satisfying the prevailing constraints such as load balance, system spinning reserve, ramp-rate limits, fuel constraints, multiple emission requirements, and minimum up and down time limits over a set of time periods (2–4, 8). With the unit commitment schedule, generating companies satisfy customer load demands and maintain transmission flows within their permissible limits. However, for power supplies that must use heavily loaded lines and transformers located far from loads, transmission flow limits throughout the system may become troublesome. Unit generation and phase shifter controls could be used to change real power distribution and alleviate transmission overflows in the system after unit commitment. But, as the system becomes more constrained by line flows, generation levels by these controls may deviate significantly from those given by the unit commitment. Furthermore, the optimal power flow or constrained economic dispatch based on unit commitment may have no solution as a result of overloaded transmission flows in the power system.

Transmission flow limits have been represented in unit commitment formulation as linear constraints in the problem [see Rahman *et al.* (2) and Ma, Marwali, and Shahidehpour (7) for detailed analysis]. Batut and Renaud (3) ignore transmission constraints in unit commitment but account for these constraints in economic dispatch. However, the approach may not be efficient because it attempts to determine unit commitment strictly based on its generation cost characteristic and then schedules the generation allocation according to the commitment schedule, which may require immense computation to adjust the commitment to conform to transmission constraints. Ruzic and Rajakovic (4) relax transmission constraints by adding them to the objective function. But, computation results are limited to one or two transmission lines. Computation time increases considerably when two transmission lines are added. For a medium-sized system with 100 transmission lines, the computation time is not acceptable for practical application, and the convergence may become a serious problem in unit commitment. Because approximate unit generation levels are available during unit commitment process, which could lead to inaccuracy in the modeling of transmission flows, the inaccuracy may invalidate the unit commitment schedule.

Transmission capacity constraints present a challenge to researchers in the unit commitment. Usually, linear dc transmission constraints are considered in unit commitment formulation for system security purposes. The unit commitment schedule may not be able to keep the system in a normal state after a major transmission contingency. Unit generation and phase shifter controls could be used to change power distribution and alleviate transmission overflows in the system (preventive control). But, as the system becomes more constrained, optimal power flow or constrained economic dispatch based on unit commitment may have no solutions as a result of overloaded transmission lines in power systems. This leads to the concept of system security. The corrective control is needed for unit commitment rescheduling. The objective of unit commitment with transmission security constraints is to obtain a unit commitment schedule with minimal production cost that also ensures system security on the occurrences of transmission contingencies.

One common approach is to consider the problem in two steps. This approach ignores transmission constraints in the unit commitment but then accounts for the constraints in economic dispatch. However, this approach may not be efficient because it attempts to determine unit commitment based strictly on its generation cost characteristic rather than schedule the generation allocation according to the commitment, which may require many computations to adjust the commitment to conform to transmission constraints. Another approach by Ruzic and Rajakovic (4) and Rahman *et al.* (2) is to consider transmission constraints by relaxing them and adding them to the objective function. However, the computation time increases considerably when transmission lines are added. For a medium-sized system with about 100 transmission lines, the computation time is not acceptable for practical applications, and the convergence may become a serious problem in unit commitment. Another problem with modeling transmission constraints in unit commitment is that only approximate unit generation levels are available during unit commitment process (i.e., the exact generation will be determined by economic dispatch). The approximate solution could lead to inaccuracy in modeling line flows. It means that transmission constraints could be violated in economic dispatch even though they were satisfied in calculating unit commitment; the inaccuracy may invalidate unit commitment schedule.

Batut and Renaud (3) presented an augmented Lagrangian technique to deal with generation scheduling with transmission constraints. This method allows us to control the oscillation effectively and improve iteration convergence in Lagrangian relaxation solutions for unit commitment. However, inequality (system spinning reserve and transmission) constraints as well as equality (system load demand) constraints are added as quadratic penalty terms. For each inequality, a heuristic method introduces equality constraints by applying slack variables. Because there are many transmission lines in large-scale power systems, this implementation will introduce a large volume of new variables and increase the dimension of the problem inevitably, thus making the model very difficult to solve. The iterative solution procedure for the decomposed problem is depicted in Fig. 3 and provides a minimum cost generation schedule while satisfying transmission constraints. Because these two problems are easier to solve and require less complicated and smaller computing capabilities, the generating scheduling becomes more accurate and faster.

Transmission Line Maintenance

In an increasingly competitive environment, the risk of lost sales caused by maintenance must be taken more seriously. A common integrated planning decision that confronts transmission providers is the line maintenance scheduling during which the transmission provider may be unable to sell as much service as it would if all lines were fully operational. Scheduling line maintenance during a low wheeling period would be a smart move, but it might also mean paying overtime to contractors and suppliers to work at late hours. In addition, transmission

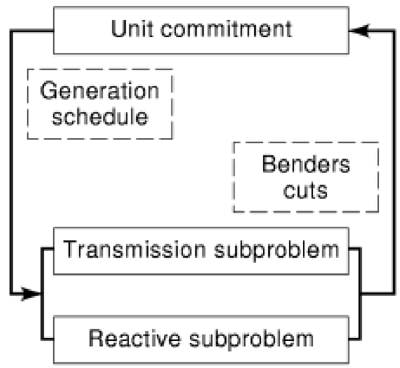

Fig. 3. The solution procedure for transmission security constrained unit commitment.

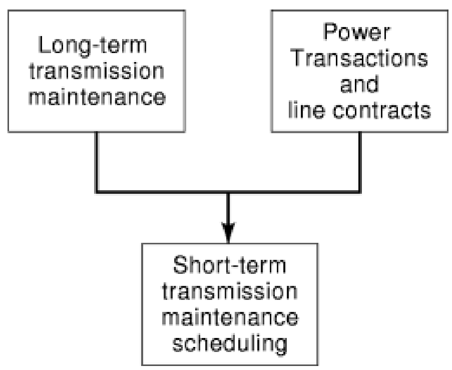

Fig. 4. Transmission maintenance schedule.

providers must maintain the service quality and system reliability when transmission lines are on maintenance by considering voltage and transmission capacity limits. The maintenance schedule of transmission lines spans over different time periods (given in Fig. 4). In this connection, the following functions are identified:

(1) *Long-term transmission maintenance scheduling.* The long-term period (one year) is divided into intervals (weeks) and a maintenance scheduling strategy for the intervals is derived.
(2) *Power transaction and transmission contracts.* In dealing with power transactions, generation providers can sell power to any retailer or direct-access customers through bilateral contracts, as well as to power exchange. Transmission line contracts, such as network services based on time usage or path service based on reservations, will follow after the power transactions process.
(3) *Short-term transmission maintenance scheduling.* Given the maintenance window by scheduling in Step 1, and generation schedules and line contracts in Step 2, the hourly line maintenance is formulated to maximize transmission providers' revenues while satisfying the system reliability.

Long-Term Maintenance Scheduling. The objective function to be minimized consists of two terms. The first term is the weekly transmission line maintenance cost and the second term is the expected loss of revenue caused by line maintenance. The expected loss of revenue is proportional to the scheduled energy that cannot be delivered to receiving buses as a result of line maintenance.

The constraints are maintenance and network constraints. We use a maintenance window (time interval) approach to represent maintenance constraints (e.g., lines must be available before their earliest possible period of maintenance and after their latest possible period of maintenance). Additional constraints consisting of crew and resources availability, seasonal limitations, and favorable schedules are incorporated into maintenance constraints. The network constraints are relaxed for satisfying convexity conditions so that an optimal solution can be obtained for the long-term horizon. The relaxed constraints are then gradually reintroduced as we get to the short-term horizon. Thus, in the long-term horizon, we solve a relaxed problem using a transportation model in which Kirchhoff's laws are ignored. The transportation model is employed to represent operational limits, the peak load balance equation, and generating and line capacity limits. In order to avoid overoptimistic planning, generation and transmission outages are taken into account (composite reliability evaluation).

Power Transactions. Transmission providers may offer firm and nonfirm reservations. In firm reservations, transmission curtailment does not occur for economic reasons. Transmission service is to be curtailed only in cases where system reliability is threatened or in emergency conditions. Firm transmission service is mostly provided to utilities' native loads and, under contract, to firm wheeling transactions. In nonfirm reservations, the transmission provider has the right to interrupt all or part of the transmission service for any reason including economic. To formulate the firm and nonfirm reservations, we include them in real power flow constraints and objective functions. To accommodate the flexibility of canceling nonfirm reservations, we introduce slack variables (load curtailment) into the network formulation. Canceling transaction or purchasing reactive power to support the voltage profile is related to the loss of revenue.

Short-Term Maintenance Scheduling. The objective function consists of three terms. The first term is the hourly transmission line maintenance cost. The second term is the loss of revenue caused by line maintenance (recallable contracts). The third term relates to additional reactive power requirements (either recallable or purchased power) to support the voltage profile caused by line maintenance.

The sets of constraints included in the formulation are maintenance and network constraints. Maintenance constraints are determined by the long-term maintenance scheduling. Network constraints consist of limits on real and reactive power flows. In the short-term horizon, real power flows obey Kirchhoff's laws to represent load balance and other operational constraints. Additional reactive power may be available by canceling some reactive power transactions, purchasing additional reactive power, and adjusting tap-changing transformers.

Solution Methodology. We coordinate long-term and short-term transmission maintenance problems. First, we solve long-term transmission scheduling. Given the maintenance window by long-term scheduling, generation schedules, and line contracts, the hourly line maintenance is formulated to maximize transmission providers' revenues while satisfying the system reliability. The long-term and short-term are solved using Benders decomposition (12).

Test Cases. We use a 186-line system with an IEEE-118 bus network to test the proposed method. A 3-month study period, weeks 18 to 29 in summer, is considered. Figure 5 shows the weekly peak load pattern with an annual peak load of 7202 MW. For long-term scheduling, line maintenance cost is assumed ($\$0.45 \times 10^2$/km) and outage duration is assumed (11 h). Transmission lines have a 300 MW capacity (11).

Table 1 shows optimal maintenance windows within the study period for long-term maintenance scheduling. Most of the lines are scheduled for maintenance in the lowest peak load (week 27 in Fig. 5) during the 12-week horizon.

Next, we proceed to short-term maintenance scheduling. The task of short-term maintenance scheduling is to determine the optimal maintenance hour within maintenance week. The maintenance duration of each line is an hour per-day for one week, and the maintenance cost are given in Fig. 6.

We consider week 27 as a case of short-term maintenance scheduling. Lines 1 to 10 are considered to be on maintenance in week 27 with a daily transaction pattern given in Fig. 7. The transmission contingency analysis indicated that worst transmission contingency is the outage of line 37 to 38. Transmission provider may relieve

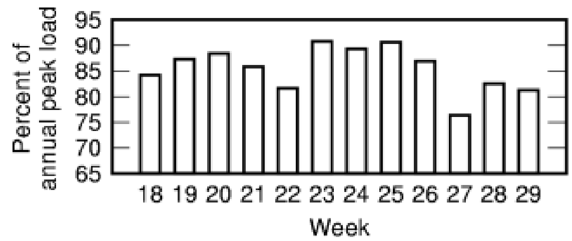

Fig. 5. Weekly peak load.

Table 1. Transmission Maintenance Windows

Line	Week	Line	Week
1–10	27	17–21	22
11–16	29	22–24	28

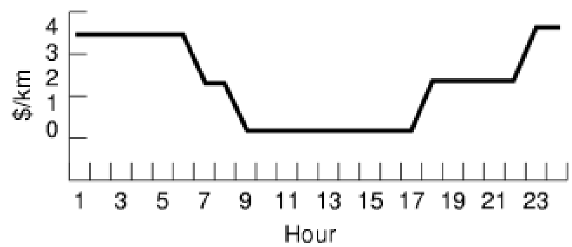

Fig. 6. Hourly line maintenance cost in week 27.

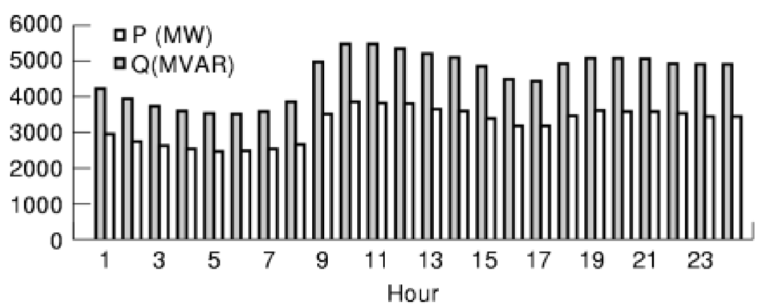

Fig. 7. Daily transactions in week 27.

the violations resulting from the worst contingency by interrupting recallable contracts with perceived loss of revenue given in Table 2.

In addition, a transmission provider may consider two options to provide additional reactive power caused by line maintenance. The first option is to cancel reactive power delivery with a loss of revenue given in Table 2. The second option is to purchase reactive power from ancillary service providers. The cost of purchasing additional reactive power is given in Table 3.

Table 2. Cost of Recallable Contracts in Week 27

Bus	Percent of Total Load	Loss of Revenue ($/MWh)	Loss of Revenue ($/MVAR)
15	2.12	11.87	1.18
42	2.26	8.40	0.84
49	2.05	16.21	1.62
54	2.66	18.47	1.84
59	6.53	8.98	0.90
74	1.6	27.88	2.79
80	3.06	21.40	2.14
89	3.84	17.96	1.80
112	1.60	19.28	1.93
116	4.34	9.53	0.95

Table 3. Cost of Ancillary Services for Reactive Power in Week 27

Bus	Load (MVAR)	Cost ($/MVAR)
65	277	1.3
66	277	1.2
69	465	1.1
80	390	1.0
89	550	0.8
100	230	0.9

Table 4. Line Maintenance Schedule Without Network Constraints

Line	Hour	Line	Hour
1	12	6	9
2	16	7	13
3	17	8	14
4	10	9	17
5	11	10	15

If transmission and voltage constraints are not included, there will be flow violations on lines 8 to 30, 69 to 3, and 89 to 92, and voltage violations in buses 107 and 112. Most of these violations occur during heavy transaction periods. The corresponding hourly line maintenance schedule is shown in Table 4. It is obvious that the schedule gives the minimum maintenance cost because most lines are scheduled to be on maintenance between hours 9 and 17, which according to Fig. 7 represents the cheapest maintenance cost during these hours.

Table 5. Line Maintenance Schedule with Transmission and Voltage Constraints

Line	Hour	Line	Hour
1	9	6	17
2	19	7	7
3	21	8	8
4	16	9	22
5	15	10	18

After transmission and voltage constraints are considered, 110.6 MW contract at bus 42 is interrupted at hours 19 and 21, 205 MVAR contract at bus 59 is also interrupted at hours 14 and 15. Transmission provider has to purchase 138 MVAR at hour 1 and 187 MVAR at hours 14, 15 and 16 through bus 89. The maintenance schedule which satisfied transmission security and voltage constraints is given in Table 5. The maintenance cost increases to $8244.08 in Table 5, as compared to $4655.64 in Table 4, in order to avoid flow and voltage violations in the network.

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