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The authors express their gratitude for the financial support of the MIT Energy Lab Consortium on New Concepts and Software for Deregulated Power Industry, EPRI/ARO contract number EPRI-W08333-03, the FOMEC fellowship from Ministry of Education of Argentina, and the doctoral fellowship from the Italian Ministry of University and of Scientific and Technological Research.

Assessing Reliability as the Electric Power Industry Restructures

Current criteria and methods for reliability assessment and provision do not provide the quality of service requested by regulators on behalf of consumers. Although some improvements can be envisioned, a new paradigm may be necessary in which reliability responsibilities are clearly assigned to suppliers and wire companies, with understanding of verifiable reliability-related products seen by the customer.

Marija D. Ilić, José R. Arce, Yong T. Yoon, and Elena M. Fumagalli

The growing pains of electric power industry restructuring are becoming quite visible to the general public. These are reflected either through undesired service interruptions and/or highly volatile wholesale electricity prices. In this article, we consider issues related to the continuity of service, describing major changes in fundamental principles underlying reliable electric power service as the industry restructures. We suggest that the service interruptions are to a large extent the result of a significant lack of regulatory incentives for maintaining and improving reliability of a grid and its efficient use. While this is true even in the regulated industry, the situation becomes critical as the evolving electricity markets require transmission service beyond the conditions for which it was originally designed. The implications are weak relations between current operating and planning practices and the reliability seen by the customers, as well as inadequate use of poten-

 1040-6190/01/$–see front matter PII S1040-6190(01)00170-1

tially powerful technologies, particularly software tools, for implementing a desired level of reliability.

I. Reliability Management under a Vertically Integrated Utility Structure

The operating and planning practices of a vertically integrated utility are defined and coordinated based on the reliability requirements, or criteria, defined by the regulators. This article reviews and assesses the reliability criteria currently used and the effectiveness of current industry practices (decision-making "technical standards" and supporting software) for meeting reliability requirements. We analyze the relation of the electricity tariffs in place and the incentives to meet the reliability requirements by analyzing technical standards used.

Regulatory requirements for reliable service are typically set at the state level because they are relevant for customers directly connected to a distribution network. The utilities are required to serve customers beyond a minimum interruption threshold; the customer average interruption duration index (CAIDI) and the customer average interruption frequency index (CAIFI) are typical of current regulatory requirements on behalf of customer.

In a vertically integrated utility, these requirements are implemented using "top-down" or system-type criteria (the technical standards) with the expectation that if these criteria are met, the indices measured at a customer site would also be met. The loss of load probability (LOLP) and the expected value of energy not served (EENS) are the typical indices used for measuring system-wide reliability level.

The LOLP computes the probability that the entire system load is higher than the generation supply available in the system for a given period by comparing the generation capacity with peak demand subject to possible equipment outages. Although the index provides information on service interruptions, the severity of the interruptions is not measured.

The situation becomes critical as the electricity markets require transmission service beyond conditions for which it was designed.

The EENS calculates the expected value of the energy not being served by looking (via simulation) at the magnitude and duration of load exceeding the available generation in case of generator and transmission line outages. The severity of interruption is captured in terms of magnitude and duration by this index.

In this article we use only LOLP to compare the results of operators' actions with their effect on reliability as seen by the customers.

II. Industry Practices for Meeting Reliability Requirements

Based on the LOLP, a vertically integrated utility determines the amount of generation capacity required. This capacity has historically been differentiated into generation needed for compensating small random fluctuations in demand around the forecasted load (automatic generation control, or AGC), and reserve generation for supplying customers under severe, unpredictable equipment outages (projected load demand). Long-term changes in projected demand are met by building new power plants and by designing enough transmission to deliver the power. This article does not discuss the AGC-related criteria and the need for their changes under restructuring.[1] Here we study operations planning criteria and methods, concentrating on reliability methods for the extra-high voltage transmission grid.

The short-term operating practices for meeting the LOLP for the anticipated (known) load are generally based on so-called $(N - 1)$ security criteria. The system operator dispatches available generation to minimize the total operating cost of providing the load in such a way that if any single large equipment outage (generator or transmission line) takes place, the load remains unaffected,

  PII S1040-6190(01)00170-1

at least for a certain duration of time. Many powerful software tools exist to assist system operators with this task. This criterion is entirely deterministic.

The critical issue to observe here, however, is that there is no direct relation between the LOLP and the deterministic (N − 1) security criterion as currently practiced. **Example 1** shows that the amount of reserve needed to meet a pre-specified LOLP depends on the actual energy dispatch, even when there is sufficient generation reserve, because the ability of the transmission system to deliver these reserves depends heavily on the likely status of the system. The inability to deliver could be caused either by so-called "congestion," i.e., an inability to deliver power even when the transmission system is intact, or by transmission line outages.

As a consequence, like it or not, current industry practices are not designed to guarantee a pre-specified LOLP needed on the customer side. This is true even in the simplest technical setup when "congestion" refers to the steady-state problems in delivering real power (MW), while voltage and stability constraints are not accounted for.[2]

In subsequent Examples, we suggest that it is indeed possible to define the optimal (least-cost) amount of reserve to ensure a pre-specified LOLP index as the energy dispatch changes. Unfortunately, as will be shown, the computational methods for doing this are quite involved and are not currently used by system operators in even the most advanced control centers. It is our suggestion that only with the right regulatory incentives will the effort be made to develop tools of this type.

III. Reliability Management by the Independent System Operators

Over the past several years we have witnessed a strong effort, particularly by the North Ameri-

Example 1

What Is a System Operator Doing to Meet Reliability?

The main objective of this example is to illustrate the criteria and methods underlying operating practices for providing reliable service by vertically integrated utilities. This example concerns methods used by the system operators of the EHV transmission system, and thus is relevant only for reliability assessment at the wholesale level. The reliability issues as seen by the small users at the distribution system level and the relations between the two are discussed briefly toward the end of this article.

Consider a small fictitious electric power system, shown in **Figure 1**, owned and operated by a vertically integrated LightCo.

The company has knowledge on availability of each transmission line ij. For purposes of numerical illustration, say that each line has availability $v_{ij} = 0.99$, or probability of failure $1 - v_{ij} = Pr(F)_{ij} = 0.01$. LightCo also knows the operating cost functions $C_i(Q_{Gi}) = a_i Q_{Gi}^2$ of its four generators.

A typical approach to ensuring the (N − 1) security criteria is to provide a reserve requirement determined as $R(MW) = \max\{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}\}$, which corresponds to the capacity of the largest power plant. For the (radial) transmission topology of this example, and assuming that all generators are always functional, we analyze the role of transmission grid reliability. In this case the reliability requirement is equivalent to having generation reserve which corresponds to the $R(MW) = \max\{F_{15}, F_{25}, F_{35}, F_{45}\}$, where F_{ij} is a real power line flow between nodes i and j. Then, based on this requirement, this reserve R is allocated to different generators (R_1, R_2, R_3, R_4). The reserve determined this way results in some (not pre-specified) LOLP as seen by the load at bus 5.

To illustrate numerically the issues of interest, in increased order of complexity, consider first the simplest scenario when transmission lines have sufficient capacity, i.e., there is no congestion problem. In this case, the only scenario in which load does not get served is if a transmission line does not deliver because it is not there to make a connection between the supply and demand points. Two cases are analyzed, first when the cost

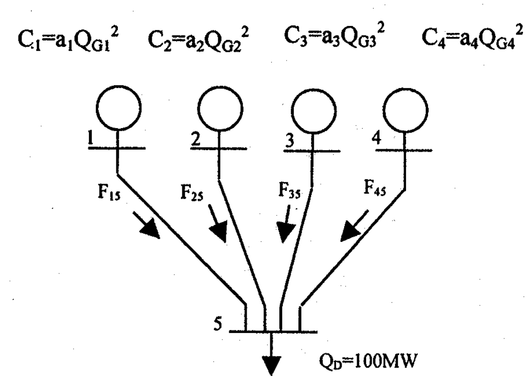

Figure 1: Example of a Small Power System

can Electric Reliability Council (NERC), to enforce the existing industry practices for ensuring reliable operation by independent system operators (ISOs), as these evolve. These efforts are possibly best illustrated in NERC documents concerning interconnected operating services.[3] The matter of the actual amount of reserve required, and the mechanisms for its implementation, have been the subject of major debates. For instance, the New England ISO does not have a separate market for reserve, whereas the California ISO does. The implementation of the required reserve is through the so-called single settlement system or a multi-settlement system.[4] The entire debate misses the issues highlighted in Example 1, namely, the conceptual impossibility of meeting a reliability level desired through the types of criteria and software methods currently in use.

Example 2 shows that, much the same way as a system operator in today's vertically integrated utility is incapable of delivering a pre-specified reliable service to a user because of the limitations of the criteria and methods used, this problem only gets enhanced as an ISO attempts to do the same. In addition to the problems illustrated above, the task is made more difficult by the fact that the reliability reserve gets dispatched through a market, without adjusting the amount of reserve needed to the conditions of the energy market and the transmission status.

IV. Possible Criteria and Methods for Ensuring Reliability at the Customer Level

It can be concluded from Examples 1 and 2 that in order to define the amount and allocation of reserve for ensuring a pre-specified level of reliability, it is necessary to consider explicitly the transmission capacity equations such that the reliability requirement is fulfilled. Solving this

Example 1

of all generators are the same and, second, when the power plants are vastly different in costs.

If the operating cost of all generators is the same, i.e., $a_1 = a_2 = a_3 = a_4 = 1$ \$/MW^2 per hour, the simple minimal total cost dispatch problem results in equal energy dispatch $Q_{G1} = Q_{G2} = Q_{G3} = Q_{G4} = 25$ MW necessary to meet the given load of 100 MW. In order to meet the reserve requirement R(MW) = $\max\{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}\} = 25$ MW, typical heuristic-based practice is to allocate reserve in the same proportion as energy dispatch subject to the constraint that the sum of reserve for three units be equal to 25 MW. This results in reserve allocation $R_1 = R_2 = R_3 = R_4 = 8.33$ MW.

A simple analysis of the implications of this reserve allocation shows that if one transmission line is out, the system has 3×8.33 MW reserve to replace the output of 25 MW that was affected, so load deficit is zero for any single contingency. Therefore, the corresponding probability that some deficit, or loss of load, occurs is computed by looking at the probability that two or more lines are out, in which case the deficit is no longer zero. This probability is computed based on the probability of line availability as LOLP = Pr(def > 0) = 1 − Pr(all lines operational) − Pr(any single line out). Given the specified line availabilities v_{ij} this results in:

$$\text{LOLP} = 1 - 0.99^4 - (4 \times 0.01 \times 0.99^3) = 5.9203\text{e-}004. \quad (1)$$

For purposes of further illustration, we now assume that this LOLP is both the value desired by customers and that set by regulators. Consider next, then, the situation where LightCo owns very different power plants with different cost structures. This is seen in the values $a_1 = 1, a_2 = 2, a_3 = 3, a_4 = 4$ \$/MW^2 per hour in the operating cost function. In this case, the result of least-cost energy dispatch to meet the desired 100 MW load results in energy schedules of $Q_{G1} = 48$ MW, $Q_{G2} = 24$ MW, $Q_{G3} = 16$ MW, and $Q_{G4} = 12$ MW. The corresponding reserve requirement R(MW) = $\max\{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}\} = 48$ MW could be allocated proportionally to the energy schedules, subject to the constraint that the sum of reserve for three units be greater than or equal to the Q_{Gi} affected. This leads to the reserve allocation of $R_1 = 0$ MW, $R_2 = 22.15$ MW, $R_3 = 14.77$ MW, and $R_4 = 11.08$ MW.

The implications of this energy schedule and reserve allocation are that if one line is not operational, the system still has enough reserve available. The criterion that under the most severe contingency load still does not see any deficiency leads to:

$$\begin{aligned}\text{LOLP} &= \Pr(\text{def} > 0) = 1 - \Pr(\text{all lines operational}) \\ &\quad - \Pr(\text{any single line one out}) = 1 - 0.99^4 \\ &\quad - (4 \times 0.01 \times 0.99^3) = 5.9203\text{e-}004. \end{aligned} \quad (2)$$

This is the same as in the case when all the power plants have the same cost structure.

Consider next a more complicated scenario for the same system, assuming congestion capacity of each line to be 30 MW. In this case, for equal energy cost, $a_1 = a_2 = a_3 = a_4 =$

problem requires determining the amount of adequate reliability reserve, and the allocation of adequate reserve, in order for the users to obtain reliable reserve as specified according to a pre-agreed reliability index.

Example 3 shows how a pre-specified LOLP can be determined by an ISO, given the right software. A similar example could be worked out to illustrate the same for a system operator in a vertically integrated utility. Example 3 shows the need for more adaptive methods of determining the amount of reserve and its allocation for the pre-specified reliability product. In terms of methods, this by orders of magnitude harder to do than what is currently practiced.

V. Underlying Principles for Providing Reliable Service under Industry Unbundling

It is important to recognize that the entire industry is undergoing functional and corporate unbundling, and that it is no longer realistic to expect that risks associated with reliable service would necessarily be borne by just one entity. In order to address this important turning point, it would help to assess the approach to reliability services by different businesses, including power suppliers, wire (transmission and/or distribution) providers, and finally, the customers.

A. A Decentralized Approach to Reliability

As the industry restructures, it has become imminent that each entity will have its own business objectives, both short-term and long-term. Not all of these decentralized objectives will be consistent with the objectives of the vertically integrated utility in which decisions are made in a coordinated way under the assumption that generation, transmission, and distribution are all owned and managed by a single entity.

We suggest that it is extremely helpful to think of reliability pri-

Example 1

1 \$/MW^2 per hour, the optimal dispatch subject to the transmission line flow limits still results in the same least-cost energy dispatch $Q_{G1} = Q_{G2} = Q_{G3} = Q_{G4} = 25$ MW. If the reserve requirement $R(MW) = \max\{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}\} = 25$ MW gets allocated in proportion to the energy dispatch (subject to the sum of reserve for three units being equal to 25 MW), the result is the same reserve allocation, $R_1 = R_2 = R_3 = R_4 = 8.33$ MW, as when the transmission flow constraints did not exist.

In this case, however, an analysis of the resulting reliability as seen by the load shows that, whereas if one transmission line is not in service the system would have sufficient generation reserve of 3×8.33 MW to replace the 25 MW not delivered from one generator via the transmission line which has failed, the transmission lines are now congested at 30 MW, implying that the deficit is different from zero for any single contingency. Therefore, in this case the reliability seen by the load is significantly reduced to $LOLP = \Pr(\text{def} > 0) = 1 - \Pr(\text{all lines operational}) = 1 - 0.99^4 = 0.0394$.

Observe that even though the system has enough generation capacity reserve to support the single output of any of the generators (line outage–generation affected), the transmission system is not able to transfer the reliability-related redispatched power, and the load has less reliability than desired (LOLP of 0.0344 > LOLP of 5.9203e-004).

If the company owns power plants whose operating costs are different, characterized by $a_1 = 1$, $a_2 = 2$, $a_3 = 3$, $a_4 = 4$ \$/MW^2 per hour, and assuming that the transmission capacity limits are $F_{15} \le 50$ MW, $F_{25} \le 30$ MW, $F_{35} \le 50$ MW, $F_{45} \le 50$ MW, respectively, this results in the least-cost dispatch of $Q_{G1} = 48$ MW, $Q_{G2} = 24$ MW, $Q_{G3} = 16$ MW and $Q_{G4} = 12$ MW. Following the same current practice, the reserve requirement $R(MW) = \max\{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}\} = 48$ MW and its allocation in proportion to the energy schedules subject to the constraint that the sum of reserve for three units be greater than or equal to the Q_{Gi} affected, we obtain $R_1 = 0$ MW, $R_2 = 22.15$ MW, $R_3 = 14.77$ MW, and $R_4 = 11.08$ MW. However, line 25 now has a capacity limit of 30 MW, and for the case where line 15 is out, the system *cannot* supply completely the demand (deficit $= 48 - 6 - 14.77 - 11.08 = 16.15$ MW). Consequently:

$$\begin{aligned} LOLP = \Pr(\text{def} > 0) &= [1 - \Pr(\text{all lines operational}) \\ &\quad - \Pr(\text{any line out except line 15})] = 1 - 0.99^4 \\ &\quad - 3 \times 0.01 \times 0.99^3 = 0.0103. \end{aligned} \tag{3}$$

This scenario shows that even though the system has enough generation capacity reserve to support the single output of any of the generators (line outage-generation affected), the transmission system is not able to transmit the redispatch for the case that line 15 is out; consequently, the system is less reliable than desired (LOLP of 0.0103 > LOLP of 5.9203e-004). ■

marily as a risk-taking and management process, because one deals with the problem of ensuring uninterrupted service despite unexpected changes.[6] In vertically integrated utilities these uncertainties are caused by the unpredictable demand deviations and by equipment outages. In an unbundled industry, the uncertainties also derive from incomplete information about other parts of the industry. For example, it is well known that it is very difficult to plan a new power plant without knowing plans for transmission enhancements, and vice versa. Similar concerns arise in light of shorter-term operations planning for meeting a desired LOLP.

A particularly difficult aspect of industry unbundling concerns dependence of risk management on the industry structure in place. For example, in a vertically integrated industry the risk is seen by the customer, who is not guaranteed to be delivered a pre-specified service quality, as shown in Examples 1, 2, and 3.

In an industry structure characterized by a full corporate unbundling of generation, transmission, and distribution, responsibilities for risk-taking have to be clearly defined through the contractual agreements among different entities. This requires, first of all, a definition of reliability-related products for which there are sellers and buyers. In this environment, technical "standards" are replaced by contractual expectations. In a rare case that the contracts are breached, there ought to be a well-understood penalty mechanism.

B. Approach of Generation-Serving Entities to Reliability

Much literature exists on the objectives of competitive power suppliers and their methods.[7] Without getting into specifics, their major objective is to sell the product (power) in order to make the most profit while minimizing the risk that the profit will not materialize.

The power suppliers view the risk associated with reliability as

Example 2

What Is an ISO Doing to Meet Reliability?

One of the qualitative changes in applying current operating practices for reliable service under competition is the fact that the reliability reserves are offered in some ISO structures in a way that the generators bid separately into a reserve market according to some bid function for providing reserve. If the cost of reserve is considered to be different than the energy cost, this reserve is sometimes allocated at least (reserve) cost subject to the constraints on available reserve (R_i^{min}, R_i^{max}). Let us assume for simplicity that this bid curve is linear; i.e., $C_i(R_i) = b_iR_i$. (This is used just as an illustration of the issues of interest, and therefore any other bid function could be chosen.) In our example, the energy market is cleared first, and then the reserves are provided through a separate market so that the total cost of reserve bids purchased is minimized, and also each reserve bid has a reserve capacity limits (R_i^{min}, R_i^{max}).

To recognize the sensitivity of the reliability outcome as seen by the customer on the amount of reserve chosen, we recognize here that this generally heuristic (operating conditions independent standard) could vary with a market design. A slightly different heuristic standard for the total reserve required could be something like $R(MW) = \max\{20\%Q_D, \max\{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}\}\} = \max\{20\ MW, 25\ MW\} = 25\ MW$. The amount 20 percent Q_D is used as an example only. Assume for purpose of illustration that $b_i = 0.5$ \$/MW and $R_i^{max} = 15$ MW for all four generators. This problem has no unique solution (because of the linear cost function chosen); one possible solution is again to allocate reserve equally among all four generators. Numerically, $R_1 = R_2 = R_3 = R_4 = 6.25$ MW. If one line is out, the system has 3×6.25 MW redispatched to replace the output of 25 MW that was affected, so the demand sees 6.25 MW of deficit for any single contingency, having a LOLP = Pr(def > 0) = 1 − Pr(all lines operational) = $1 - 0.99^4 = 0.0394$, which is worse reliability than the desired (LOLP = 5.9203e-004).

In another scenario, power plants have different cost functions. This is translated into different bids for both energy and reserve. If we consider values $a_1 = 1$, $a_2 = 2$, $a_3 = 3$, $a_4 = 4$ \$/MW^2 per hour in the operating cost function, the least-cost energy dispatch to meet the desired 100 MW load results in energy schedules of $Q_{G1} = 48$ MW, $Q_{G2} = 24$ MW, $Q_{G3} = 16$ MW, and $Q_{G4} = 12$ MW. The reserve requirement $R(MW) = \max\{20\%Q_D, \max\{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}\}\} = \max\{20\ MW, 48\ MW\} = 48$ MW is often implemented by minimizing the total cost of reserve, subject to the limits of available reserve of each generator (R_i^{min}, R_i^{max}). For the reserve cost of $b_1 = 0.5$, $b_2 = 1$, $b_3 = 1.5$, $b_4 = 2$ \$/MW and the reserve limits of $R_i^{max} = 15$ MW, the least-cost reserve allocation results in $R_1 = 15$ MW, $R_2 = 15$ MW, $R_3 = 15$ MW, and $R_4 = 3$ MW. With this allocation the system has enough reserve for any single contingency except for the case when line 15 is out. The system LOLP is equal to [1 − Pr(all lines operational) − Pr (any single contingency except line 15)] = $1 - 0.99^4 - (3 \times 0.99^3 \times 0.01) = 0.0103$—that is, worse reliability than the desired (LOLP = 5.9203e-004).

  PII S1040-6190(01)00170-1

being that they would not be able to sell their product. This could happen either because their power plant fails, or because it is not possible to physically deliver power to the buyer. Power suppliers are developing a variety of methods for managing risk created by their failure to produce. They are hedging their risk by having a contract with some other producer to send power in case of failure. Hedging against generation failures remains a difficult problem, because it is best done when all generators share their risks, namely through a separate market for reserve. As is well known, these markets are in their rudimentary stages.

The other, even more difficult aspect of risk-taking as seen by the power suppliers concerns transmission problems: when an agreed-upon contract cannot be executed because it is not physically deliverable. Currently, this step requires permission to use the transmission at the desired time and location, as well as paying for its use. Depending on the type of methods used by the ISOs and/or system operators in charge of the system being used, and also depending on the type of transmission tariffs, this risk could be very different. The tariffs could range from just paying an access charge, to paying for congestion, various types of transmission rights, etc. It could be seen from the methods illustrated in the prior Examples that a system operator and/or ISO do not differentiate between those classes of congestion arising when the status of all equipment is normal, and those amounting to transmission reliability, as in the case of a line failure when system users still wish to use the system.

Seen by a generator, there is no difference between not being served because congestion occurred or not being served because a transmission line failed. To the generator, this is a single risk. Therefore, generators wish to have well-defined market mechanisms for hedging against transmission status uncertainties.

The risks described here apply to

Example 2

Consider next a more interesting scenario on the same system, assuming congestion capacity of each line to be 30 MW. In this case, for equal energy cost, $a_1 = a_2 = a_3 = a_4 = 1$ \$/MW^2 per hour, the optimal dispatch subject to the transmission line flow limits still results in the same least-cost energy dispatch $Q_{G1} = Q_{G2} = Q_{G3} = Q_{G4} = 25$ MW. Say the reserve requirement R(MW) = max{20%Q_D, max{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}}} = max{20 MW, 25 MW} = 25 MW gets allocated based on the reserve bids subject to the reserve requirement and to the technical constraints $R_i^{max} = 15$ MW. Due to the fact that $b_i = 0.5$ \$/MW, the problem has no unique solution and a criterion is to allocate equally $R_i = 6.25$ MW. If one line is out, the system has 3×6.25 MW ready to be used, but the transmission system allows only $3 \times (30\text{ MW} - 25\text{ MW})$, implying that deficit not only is different from zero but also greater than the first case for any single contingency. For this scenario the LOLP is [1 − Pr(all lines operational)] = $1 - 0.99^4 = 0.0394$, which means worse reliability than the desired (LOLP = 5.9203e-004).

Another scenario is when power plants are different, characterized by $a_1 = 1$, $a_2 = 2$, $a_3 = 3$, $a_4 = 4$ \$/MW^2 per hour. Assuming that the transmission capacity limits are $F_{15} \leq 50$ MW, $F_{25} \leq 30$ MW, $F_{35} \leq 50$ MW, $F_{45} \leq 50$ MW, respectively, this produces a least-cost dispatch of $Q_{G1} = 48$ MW, $Q_{G2} = 24$ MW, $Q_{G3} = 16$ MW, and $Q_{G4} = 12$ MW. Following the same current practice, the reserve requirement R(MW) = max{20%Q_D, max{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}}} = max{20 MW, 48 MW} = 48 MW and its allocation is implemented based on minimization of the cost of providing reserve subject to the reserve requirement (MW) and the technical constraints (R_i^{min}, R_i^{max}). The result of the reserve dispatch is $R_1 = 15$ MW, $R_2 = 15$ MW, $R_3 = 15$ MW, and $R_4 = 3$ MW. Even though the system has enough reserve to fulfill the reserve requirement, the transmission capacity limits introduce other issues, with the result of having only enough reserve to support the single contingency of line 45. Consequently,

$$\text{LOLP} = \Pr(\text{def} > 0) = 1 - \Pr(\text{all lines operational}) - \Pr(\text{contingency line 45}), \qquad (1)$$

or

$$\text{LOLP} = 1 - 0.99^4 - 0.99^3 \times 0.01 = 0.0297, \qquad (2)$$

which value is worse than the desired (LOLP = 5.9203e-004). ■

both short-term horizons as well as the long-term horizons relevant to building new plants. It is for this reason that it is necessary that transmission providers offer a range of transmission products, provided on a daily basis, running through seasons and even years.

C. Approach of Transmission Providers to Reliability

Transmission providers are obligated by law to provide "open access" to all users, offering direct connection to their grid on an equal basis. In this setting they are generally being paid as much as they are used. Given the fact that transmission remains to be viewed by most as a fully regulated monopoly with a guaranteed rate of return on all capital investments, this only determines how the transmission charges of local users are affected; if the system built only for them is now being used by others, local users end up contributing less. The transmission provider, for its part, is indifferent in many ways with regard to who is being served. The only real effort on the transmission side is to do this at the minimum possible cost.

Given the very uncertain regulatory climate, transmission providers have not considered making any significant investment in enhancing their systems. Under strict environmental constraints it is very difficult to make the case for transmission upgrades given that there is much small-scale (distributed) generation on its way to being built, which partly offsets the need for enhanced transmission. This situation has resulted in transmission providers having no serious impact on system reliability, except for the requirements to maintain their existing equipment (by cutting trees, in particular).

It appears that, instead, the main system burden is placed on the evolving ISOs to provide system reliability and to manage the associated system risks. As shown in the previous examples, there is only so much that ISOs can do under current operation practices and with their typical software.

Example 3

What Can an ISO Do with the Right Software?

A tentative proposal to deal with both the reserve requirement and reserve allocation problems are to consider explicitly transmission capacity equations for each scenario, so that the reliability requirement is fulfilled.

To illustrate this idea, consider first the case when lines have 30 MW as a transmission capacity, and power plants have equal costs, $a_1 = a_2 = a_3 = a_4 = 1$ \$/MW^2 per hour. The optimal dispatch subject to the transmission line flow limits still results in the same least-cost energy dispatch $Q_{G1} = Q_{G2} = Q_{G3} = Q_{G4} = 25$ MW, as in Example 1.

For the reserve market, we assume that reserve bids are equal for generators and are characterized by $b_i = 0.5$ \$/MW in the bid function subject to the technical constraint $R_i^{max} = 15$ MW. The objective is to have at least the same or better reliability level than the pre-specified (LOLP = 5.9203e-004), and to allocate reserve considering the transmission limits.[5] As a result, the optimal reserve allocation is $R_1 = R_2 = R_3 = R_4 = 5$ MW. For any single contingency the system is only able to redispatch up to the line capacity, so it cannot allocate more than 5 MW to each unit, as the most economic of the possibilities. The system has now LOLP = Pr(def > 0) = 1 − Pr(all lines operational) = $1 - 0.99^4 = 0.0394$, which is a worse reliability level than the pre-specified in Example 1.

To meet the pre-specified LOLP of supporting any single contingency with zero deficit, the transmission system needs to be enhanced. Due to the symmetry of the example, with equal energy and reserve costs, enhancing any of the four lines is the same.

Let us assume first that the investment is in line 15 such that $F_{15} \leq 60$ MW. The energy dispatch does not change, but the reserve dispatch changes to $R_1 = 15$ MW, and $R_2 = R_3 = R_4 = 5$ MW. Now the system has enough reserve to support any single contingency except when line 15 is out. Consequently, LOLP = Pr(def > 0) = 1 − Pr(all lines operational) − Pr(any single contingency except line 15 out), or LOLP $= 1 - 0.99^4 - (3 \times 0.99^3 \times 0.01) = 0.0103$.

If, additionally, line 25 is improved to $F_{25} \leq 60$ MW, the reserve dispatch is $R_1 = R_2 = 15$ MW, and $R_3 = R_4 = 5$ MW, and the system finally supports any single contingency having a LOLP of 5.9203e-004.

A second, more interesting case is when both energy and reserve costs are different for different generators and transmission capacity limits ($F_{15} \leq 50$ MW, $F_{25} \leq 30$ MW, $F_{35} \leq 50$ MW, $F_{45} \leq 50$ MW). With $a_1 = 1$, $a_2 = 2$, $a_3 = 3$, $a_4 = 4$ \$/MW^2 per hour, the dispatch results $Q_{G1} = 48$ MW, $Q_{G2} = 24$ MW, $Q_{G3} = 16$ MW, and $Q_{G4} = 12$ MW.

For the reserve part of the problem, let us assume that each generator has different reserve bids, $b_1 = 0.5$, $b_2 = 1$, $b_3 = 1.5$, $b_4 = 2$ \$/MW, and the same technical constraint $R_i^{max} = 15$ MW. The objective is to have at least the same or better reliability

Given the fact that an ISO does not own generation, this could be done in some way by creating reserve markets for both generation and transmission reliability. This is unlikely to be carried out by ISOs who do not view their function as risk-taking or profit-making. (An exception would be for-profit, performance-based ISOs, which would be genuinely interested in coming up with the most adequate criteria and software for their performance.)

Another possible approach is to create performance-based transmission providers, whose products and incentives for risk management would be defined through market rules, rights, and responsibilities.[8] In this scenario, a transmission provider would quickly learn that it requires a different contract for serving a generator for energy than a generator who has a hedging contract for power in case this generator fails. It is quite plausible for a transmission provider of the future to offer an unbundled transmission product, one for congestion management and a second one when a generator participates in a reserve market. On the other hand, it is possible that a transmission provider would offer a single product for delivering transactions under well-defined terms, but at a different price. It is of critical importance that a transmission provider offer only products over which he has control, such as the improved reliability related only to transmission line failures. Based on the demand for these products, a transmission provider might, over time, dare to invest in the right places, without any guarantee that the investment would generate an adequate return. Creating a market of this type, together with the right tariffs and the right objectives of providing reliable transmission, is a difficult subject.[9]

D. Approach of Distribution Providers to Reliability and Customer Choice

It is important not to forget that generation and transmission reli-

Example 3

level than the requirement (LOLP = 5.9203e-004) and allocate reserve considering transmission limits $F_{15} \leq 50$ MW, $F_{25} \leq 30$ MW, $F_{35} \leq 50$ MW, $F_{45} \leq 50$ MW. In order to illustrate the necessary procedure, each scenario will be considered explicitly, and then the final reserve dispatch will be defined such that $R_i = \max\{R_i \text{ for each scenario}\}$.

When line 15 is out, the system needs to have enough reserve to substitute the output of generator located at bus 1, so $R_2 + R_3 + R_4 = 48$ MW, and at the same time the transmission capacity limits need to be considered, resulting in

$$Q_{G2} + R_2 \leq 30 \text{ MW} \rightarrow R_2 \leq 6 \text{ MW},$$
$$Q_{G3} + R_3 \leq 50 \text{ MW} \rightarrow R_3 \leq 34 \text{ MW, and}$$
$$Q_{G4} + R_4 \leq 50 \text{ MW} \rightarrow R_4 \leq 38 \text{ MW}.$$

Finally, the reserve is allocated economically based on the reserve bids and technical constraints, resulting in $R_2 = 6$ MW, $R_3 = 34$ MW, and $R_4 = 8$ MW.

In a similar way, when line 25 is out, the system needs to have reserve $R_1 + R_3 + R_4 = 24$ MW and each transmission capacity limit needs to be considered explicitly.

$$Q_{G1} + R_1 \leq 50 \text{ MW} \rightarrow R_1 \leq 2 \text{ MW},$$
$$Q_{G3} + R_3 \leq 50 \text{ MW} \rightarrow R_3 \leq 34 \text{ MW, and}$$
$$Q_{G4} + R_4 \leq 50 \text{ MW} \rightarrow R_4 \leq 38 \text{ MW}.$$

The optimal result for this scenario is $R_2 = 2$ MW, $R_3 = 22$ MW, and $R_4 = 0$ MW.

Similar analysis is needed for scenarios when line 35 and line 45 are out of service. For line 35, we have $R_1 + R_2 + R_4 = 16$ MW,

$$Q_{G1} + R_1 \leq 50 \text{ MW} \rightarrow R_1 \leq 2 \text{ MW},$$
$$Q_{G2} + R_2 \leq 30 \text{ MW} \rightarrow R_2 \leq 6 \text{ MW, and}$$
$$Q_{G4} + R_4 \leq 50 \text{ MW} \rightarrow R_4 \leq 38 \text{ MW};$$

i.e., $R_1 = 2$ MW, $R_2 = 6$ MW, and $R_4 = 8$ MW. Finally, for line 45 out, it is necessary to have $R_1 + R_2 + R_3 = 12$ MW, and

$$Q_{G1} + R_1 \leq 50 \text{ MW} \rightarrow R_1 \leq 2 \text{ MW},$$
$$Q_{G2} + R_2 \leq 30 \text{ MW} \rightarrow R_2 \leq 6 \text{ MW, and}$$
$$Q_{G3} + R_3 \leq 50 \text{ MW} \rightarrow R_3 \leq 34 \text{ MW};$$

i.e., $R_1 = 2$ MW, $R_2 = 6$ MW, and $R_4 = 4$ MW.

The optimum reserve allocation considering $R_i = \max\{R_i \text{ for each scenario}\}$ is therefore, $R_1 = 2$ MW, $R_2 = 6$ MW, $R_3 = 34$ MW, and $R_4 = 8$ MW. With this formulation, the system has, for any single contingency, not only enough generation reserve but also transmission capacity. This is possible as a result of the correct consideration of the transmission equations. The reliability level is measured by the LOLP = $[\Pr(\text{def} > 0) = 1 - \Pr(\text{all lines operational}) - \Pr(\text{any single line out})] = 1 - 0.99^4 - (4 \times 0.01 \times 0.99^3) = 5.9203\text{e-}004$, which means that the system fulfills the desired reliability level. ■

PII S1040-6190(01)00170-1

ability comprise only part of the total picture. The ultimate test of reliability is seen by consumers. The reliability seen by the users will be a combination of reliability at the *interface* between transmission (EHV) and distribution (high-voltage, medium-voltage) grid and the *distribution* reliability within a distribution network. Before one even considers the notion of distribution reliability, the fact that consumers might request an improved (above minimum reliability) and a differential reliability (different for different loads) needs to be taken into account. First of all, one could show that consumers should play an active role in the setting of a reliability level at the interface, and not take it as simply a given input. Second, one needs to recognize that the reliability at the interface could be provided in various ways and at different levels from the minimum reliability. **Example 4** illustrates these ideas.

VI. Conclusions

The criteria and software methods for determining total amount of reliability reserve by a system operator in the vertically integrated utilities were never designed to be universal and to apply unconditionally to an arbitrary system. In this sense, none of the rules, or technical "standards," can be used for guaranteed reliability as requested by a customer and/or regulator in the new industry. Utilities have made efforts over time to do their best to develop rules most applicable to their particular systems, within the general guidelines of the type of criteria illustrated in this article. In particular, it is illustrated here that the availability of generation reserve (adequacy) will not ensure that this reserve gets delivered to the users under certain contingencies. This is mainly because, when an attempt is made to deliver reserve under transmission contingency, a transmission grid often becomes a bottleneck, often at some other path.

Example 4

Improved and Differential Reliability at a Consumer Level

In the example shown in **Figure 2** we added to bus 5 of Figure 1, which becomes the interface bus, a MV network with 3 loads (one of which, load 1, demands reliability above minimum) and one distributed generator (DG). The improved reliability requested by load 1 is such that for all double line contingencies at the transmission level, load 1 needs to be supplied.

As stated, let us assume that load 1 demands N − 2 reliability, and that it would be curtailed according to its demand in case of deficit at bus 5. In fact, any double contingency on the transmission side results in a deficit at the interface (bus 5), which needs to be redistributed based on the curtailment criterion of the distribution company. This means that, according to the needs of load 1, the reserve requirement at bus 5 changes.

Various alternatives exist to provide load 1 with the reliability asked for, i.e., to reduce the value of the deficit at load 1 to zero even in case of double contingencies. We consider four such alternatives.

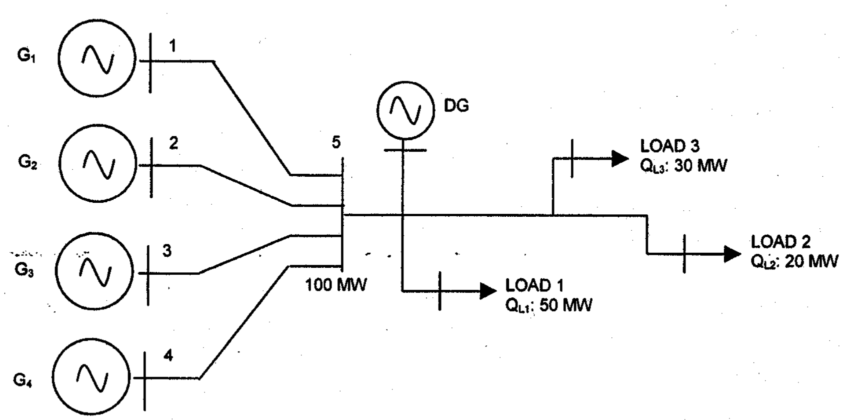

Figure 2: Customer Choice of Reliability

Generally, the ability to meet a required reserve at a user site strongly depends on the level of load, energy dispatch made to meet this load under normal operations, capacity of the transmission grid, and reliability of the transmission lines. Technical standards, such as maintaining maximum capacity of the largest power plant and the like, are only capable of guaranteeing adequacy of total supply, at best.

We stress that the regulatory rules for vertically integrated utilities have always been biased toward capital investments and not toward the most effective technology choice. Today's industry tariffs based on guaranteed rate of return on capital investment offer effectively no incentives for advanced software development of the type needed to overcome the reliability issues illustrated in this article. This has been a major obstacle to progress in the electric power industry, when compared to many other industries.

In the later part of this article we tried to show how a system operator and/or ISO could overcome the issue raised here. The fact that it has not been done as of this writing is attributable to the lack of incentives to do so.

Furthermore, based on the illustrations in Example 2, we suggest that there is no real reason to believe that an ISO could do any better or worse than a system operator as seen by the customers. Both a system operator and an ISO are using similar criteria for determining the amounts of reserve required and the software tools for their allocation. While there are some differences depending on the type of reserve implementation (bundled with energy versus unbundled, separate reserve market, etc.) and on the type of settlement systems in place, we suggest that tools that account explicitly for transmission constraints and line failures are not used by either system operators or ISOs. Because of this, one cannot look to an ISO to deal with the basic problem pointed out in this article either.

Example 4

A first way to improve reliability at the interface is to change the reserve requirement at the transmission side: A transmission provider has to provide additional reserve. We calculated the necessary amount and allocation of this additional reserve using the same assumptions as in Example 1 for cases (A) equal energy and reserve costs (no congestion), and (B) different energy and reserve costs (no congestion).

In Case A, generator operating costs are $a_1 = a_2 = a_3 = a_4 = 1$ \$/MW^2 per hour. The simple minimal total cost dispatch problem results in equal energy dispatch $Q_{G1} = Q_{G2} = Q_{G3} = Q_{G4} =$ 25 MW to meet the load of 100 MW at bus 5. According to this, the system needs to have enough reserve to perform the reserve requirement of $R(MW) = \max\{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}\} = 25$ MW. As a result, the optimal allocation of reserve is $R_1 = R_2 = R_3 = R_4 =$ 8.33 MW.

For any double contingency, the 100 MW load at bus 5 cannot be supplied, resulting in the system deficit of 33.34 MW, which needs to be redistributed based on the curtailment criterion of the distribution company. If we assume that the curtailment is proportional to the demand, for load 1 this means a curtailment of 16.67 MW.

Therefore, in order to serve load 1, even in the case of a double contingency, a transmission provider needs to allocate an additional 16.67 MW at the transmission level. Following a procedure similar to that in Example 1, the system reserves for the second contingency $R_1 = R_2 = R_3 = R_4 = 8.33$ MW just for load 1, which has now a reliability level of LOLP = Pr(def > 0) = Pr(three lines out) + Pr(four lines out of service) = $(4 \times 0.99 \times 0.01^3) + 0.01^4 = 3.9700\text{e-}006$.

In Case B, the system power plants have mutually different operating costs, $a_1 = 1$, $a_2 = 2$, $a_3 = 3$, $a_4 = 4$ \$/MW^2 per hour. In this case, the result of least-cost energy dispatch to meet the desired 100 MW load results in $Q_{G1} = 48$ MW, $Q_{G2} = 24$ MW, $Q_{G3} = 16$ MW, and $Q_{G4} = 12$ MW, and the corresponding reserve requirement $R(MW) = \max\{Q_{G1}, Q_{G2}, Q_{G3}, Q_{G4}\} = 48$ MW could be allocated proportionally to the energy schedules subject to the constraint that the sum of reserve for three units be greater than or equal to the Q_{Gi} affected. This leads to the reserve allocation of $R_1 = 0$ MW, $R_2 = 22.15$ MW, $R_3 = 14.77$ MW, and $R_4 =$ 11.08 MW.

For any double contingency, the 100 MW load at bus 5 can no longer be fully supplied. In this case, the amount of deficit depends on the lines that are out of service. In order to calculate the optimal reserve allocation, it is necessary to simulate each scenario, calculate the deficit at bus 5, and then redistribute this deficit to each load based on the curtailment criteria of the distribution company. The reserve requirement for the second contingency is the amount of reserve that makes curtailment at load 1 for each scenario equal to zero.

A transmission provider needs to allocate additionally reserve defined as the maximum of the reserve allocation for each scenario such that the curtailment for any second contin-

Again, the real reasons for this failure to use the most effective software go back to regulatory disincentives. Everything said earlier about the disincentives for adequate technologies in the vertically integrated industry continues to hold.

Finally, current operating practices (both among vertically integrated utilities and ISOs) for determining the total amount of reliability reserve and its allocation to different power plants are contrasted on the same example power system with an alternative proposal suggested here, in which the reserve is computed in order to meet a pre-specified LOLP, or some other reliability criteria verifiable at the customer locations.

We suggest that regulators need to take the leading role in supporting new paradigms for implementing reliability under competition. It is no longer prudent to expect the remnants of utilities of the past to take all the risks created by energy markets. Reliability goes hand in hand with risk, and needs business and regulatory structures that financially reward risk-taking. The imbalance with respect to risk-taking among competitive suppliers, system providers, and consumers cannot co-exist in a sustainable way. As long as suppliers willing to take risks can profit, the system providers ought to be encouraged to do the same and, in addition, be rewarded for doing it. Only then will system providers engage in developing the technological tools necessary for making the most out of the existing (wire) resources.

On the consumer side, one must ensure at least a minimal level of reliability, and understand who is providing it and at what price. It is essential to understand the basis for how this minimal reliability level is provided and the meaning of technical standards for supporting its implementation. Differentiated reliability at higher prices is also plausible, as indicated in one of the Examples in this article. In order to achieve this, it is

Example 4

gency at load 1 is zero. As a result, the goal is satisfied with R_1 = 11.57 MW, R_2 = 10.19 MW, R_3 = 13.19 MW, and R_4 = 9.889 MW, and load 1 sees a LOLP equal to Pr(def > 0) = Pr(three lines out) + Pr(four lines out of service) = $(4 \times 0.99 \times 0.01^3) + 0.01^4$ = 3.9700e-006.

A second way to improve reliability at the interface is by obtaining additional generation from a generator on the MV side (DG). The additional amount of reserve needed from the DG will be 16.67 MW in Case A. Load 1 has in this case a reliability of LOLP = 3.9700e-006. In Case B, the amount of reserve needed from the DG will be defined for the worst-case scenario (lines 15 and 25 out of service), which is R(MW) = deficit at bus 5 seen by load 1 = 46.15 MW ÷ 2 = 23.08 MW. As a result, load 1 has a LOLP of 3.9700e-006.

A third way to provide a certain level of reliability at the interface, again, through the transmission network is with a bilateral contract for reserve between a load 1 and a generator at the wholesale level. A consumer pays the generator directly to be available for providing reserve. Therefore, a transmission provider, when purchasing reserve, can count on an already-available generator, and will allocate the remaining reserve requirement accordingly. On the other hand, the consumer will receive a discount from a transmission provider for the reliability service. It is worthwhile observing that probably the most efficient way to do this is by a transmission provider calculating reserve requirement in the optimal way as in shown in the previous Examples—for the entire network—and for the consumer to pay directly one of the generators.

Finally, a different way to provide improved, differential reliability at the consumer's site is the following: Consider a particular agreement between load 1 and a distribution provider. If the load requests N − 2 reliability, this can be achieved through different curtailment criteria: In case of deficit at bus 5, load 1 will be the last one to be interrupted. This means that load 1 will not see any curtailment, while the other two loads absorb this deficit. As a result, in Case A for any double line contingency, at bus 5 the system sees a deficit of 33.34 MW, which is distributed to the loads as 0 MW curtailment for load 1, 13.4 MW curtailment for load 2, and 20 MW curtailment for load 3.

In Case B, for any double line contingency, at bus 5 the system sees a deficit at bus 5 (the magnitude depends on the scenario), which is absorbed by both load 2 and load 3 proportionally to their demands. This means that load 1 will not see any curtailment while the other two loads absorb this deficit having a reliability of LOLP = 3.9700e-006.

It is important to emphasize that all the analysis, except for the last case, was done considering the reliability at the interface. The last case opened the door for further analysis. In fact, the analysis is valid only if the distribution system is completely available, which is a very hard assumption. ■

essential to have a well-defined regulatory process that encourages performance by means of the most effective technologies.

We point out that it is extremely helpful as one goes through this assessment exercise to think of reliability primarily as a risk-taking and management process, because one deals with the problem of ensuring reliable service despite unexpected changes in demand and equipment conditions. This is generally helpful when assessing modeling, analysis, and decision-making tools used by the utilities in order to meet regulatory requirements. It is furthermore helpful for understanding the shift in risk-taking responsibilities and opportunities brought about by the willingness to take the risk on behalf of others, and particularly its dependence on the regulatory structure in place.

We finally recommend a possible framework for assessing and providing reliable service in accordance with the industry restructuring. The basic idea is to introduce verifiable measures of reliable service under functional industry unbundling. This calls for separable and verifiable reliability criteria for transmission, distribution, and power suppliers.

It is, furthermore, suggested that the reliability provision by different entities ought to have financial incentives, much in the same way that supply and demand currently have in the electricity markets. We further suggest that a market-based provision of reliable service may be the only guarantee that reliability-related risks would be handled adequately. This calls for careful development of markets for this purpose. Performance-based regulation is a must for reliable service in the future.

It is worthwhile mentioning that some utilities with advanced R&D departments, such as Electricité de France, have developed software tools that are more adequate for what is needed. Most of these tools, however, are primarily employed for planning rather than for the purpose described here, where the operator must guarantee reliable service to the users as energy dispatch varies. Much of the fundamental research on dynamic security assessment, in particular, can also be related to the need in place. The right tariff incentives would provide a solid basis for much of the technology transfer of these methods. In this article, we have restricted our analysis to the basic issues of steady-state problems in delivering available generation to the users without considering voltage-related problems and assuming no dynamic problems. All data used in the examples are hypothetical and do not reflect industry practices. ■

Endnotes:

1. For this, see M. Ilić, P. Skantze, C.N. Yu, L. Fink, and J. Cardell, *Power Exchange for Frequency Control (PXFC)*, IEEE Power Engineering Society 1999 Winter Meeting, Vol. 2, 1999, at 809–19. A detailed treatment of planning for reliability is given in M. Ilić, K. Collison, and Y. Yoon, *Development of Recommendations for the Collection of Information Describing Reliability of the Electric Power Industry during its Transition into a Competitive Market that Includes Regulated Transmission Operations and other Service Relationships*, interim report to the Energy Information Administration, July 2000. See also M. Ilić, J. Arce, and Y. Yoon, *Reliability Revisited*, MIT Energy Laboratory Technical Report EL 00-003, Aug. 2000.

2. For a more complex treatment of system constraints, see M. Ilić and J. Zaborszky, Dynamics and Control of Large Electric Power Systems (New York: Wiley & Sons, 2000), ch. 13 and 14.

3. These can be accessed at the North American Electric Reliability Council's Web site, http://www.nerc.com.

4. H. Chao and R. Wilson, *Multi-Dimensional Procurement Auctions for Power Reserves: Incentive-Compatible Evaluation and Settlement Rules*, Oct. 1999 (draft).

5. A complete mathematical formulation of this is presented in M. Ilić, J. Arce, and Y. Yoon, *Reliability Revisited*, *supra* note 1.

6. M. Ilić, *What Is System Reliability and Who Pays for It in the New Industry?* Energia (Bologna, Italy), Sept. 1998 (Available in English as MIT Energy Laboratory Working Paper EL 96004, June 1996).

7. See The US Power Market—Restructuring and Risk Management (London, Risk Publications, 1997); and P. Skantze and J. Chapman, *Price Dynamics in the Deregulated California Energy Market*, IEEE Power Engineering Society 1999 Winter Meeting, Vol. 1, 1999, at 287–93.

8. Y. Yoon and M. Ilić, *Transmission Expansion in the New Environment*, in Power System Restructuring And Deregulation: Trading, Performance And Information Technology (L. Lai, ed. New York: Wiley & Sons, 2000), ch. 5.

9. Y. Yoon, *Electric Power Network Economics: Designing Principles for For-Profit Independent Transmission Companies and Underlying Architecture for Reliability*, Ph.D. thesis, Cambridge, Massachusetts Institute of Technology, Mar. 2001.